Commentary | First Quarter 2024

Investment Research Update

From the desk of

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Market Strategy

Performance Summary: Cyclical stocks made solid gains

Investors continued a rotation toward cyclical stocks in the fourth quarter of 2023, with 10 of the 11 sectors in the S&P 500 index posting a positive return. Real estate, information technology, and financials led the way. Energy, consumer staples, and health care lagged the S&P 500.

Sector	Performance as of 12/31/23				Weight in S&P 500®
	Latest Quarter	1-Year	3-Year Annualized	Dividend Yield	
Communication Services	11.0%	55.8%	4.4%	0.7%	8.6%
Consumer Discretionary	12.4%	42.4%	3.7%	0.8%	10.9%
Consumer Staples	5.5%	0.5%	5.8%	2.6%	6.2%
Energy	-6.9%	-1.3%	36.2%	3.7%	3.9%
Financials	14.0%	12.1%	10.7%	1.7%	13.0%
Health Care	6.4%	2.1%	8.1%	1.6%	12.6%
Industrials	13.1%	18.1%	10.6%	1.5%	8.8%
Information Technology	17.2%	57.8%	15.1%	0.7%	28.9%
Materials	9.7%	12.5%	7.9%	1.9%	2.4%
Real Estate	18.8%	12.3%	6.6%	3.4%	2.5%
Utilities	8.6%	-7.1%	3.6%	3.4%	2.3%
S&P 500®	11.7%	26.3%	10.0%	1.4%	

Past performance is no guarantee of future results. Sectors defined by the Global Industry Classification Standard (GICS®); see Index Definitions for details. Performance metrics reflect S&P 500 sector indexes. Changes were made to the GICS framework on 9/24/18; historical S&P 500 communication services sector data prior to 9/24/18 reflect the legacy telecommunication services sector. The top three performing sectors over each period are shaded green; the bottom three are shaded red. It is not possible to invest directly in an index. All indexes are unmanaged. Percentages may not total 100% due to rounding.

Source: Haver Analytics, Morningstar, FactSet, Fidelity Investments, as of 12/31/23.

Scorecard: Cyclicals may still have an edge

Relative valuations provided a higher margin of safety for several cyclically oriented sectors, including materials, industrials, and financials. Also, lower rates and high valuation spreads suggested potentially attractive risk-reward for the real estate sector. Conversely, defensive characteristics could hold back communication services and utilities.

	Strategist View	Longer	Time Horizon View	Shorter	
Sector	🟩 Overweight ⬜ Neutral 🟥 Underweight	**Fundamentals**	**Valuations**	**Relative Strength**	**Comments**
Communication Services	🟥	–	–	+	Defensive characteristics may hinder performance
Consumer Discretionary	🟩		–	+	Increasingly constructive contrarian indicators, median valuation compelling
Consumer Staples	🟥	+			Earnings growth likely to lag in a broader recovery
Energy	🟥	+	+	–	Indicators suggest a negative risk-reward
Financials	🟩	–	+	–	Relative valuation may limit further deterioration
Health Care	🟩				Good combination of fundamentals and valuation
Industrials	🟩	+			Other predictive valuation indicators still compelling
Information Technology	🟩		–	+	Earnings increasingly likely to recover
Materials	🟩			–	Valuation and economic indicators are supportive
Real Estate	🟩 New	–	+		Lower rates and high valuation spreads suggest attractive risk-reward.
Utilities	🟥				Defensive characteristics may hinder performance

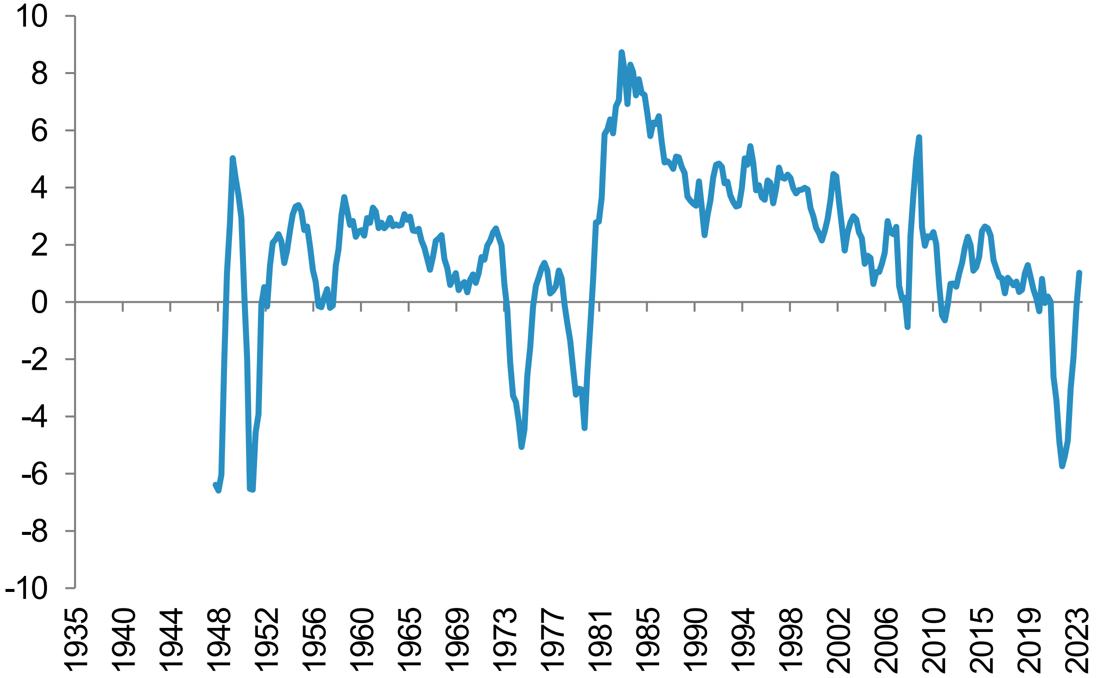
Past performance is no guarantee of future results. Strategist view, fundamentals, valuations, and relative strength are based on the top 3,000 U.S. stocks by market capitalization. Sectors defined by the GICS; see Index Definitions for details. Historical communication services data has been restated back to 1962 to account for changes to the GICS framework made on 9/24/18. **Strategist view** is as of the date indicated based on the information available at that time and may change based on market or other conditions. This is not necessarily the opinion of Fidelity Investments or its affiliates. Fidelity does not assume any duty to update any of the information. Overweight and underweight views represent opportunistic tilts in a hypothetical portfolio relative to broad market sector weights. Sector weights may vary depending on an individual's risk tolerance and goals. Time horizon view factors are based on historical analysis and are not a qualitative assessment by any individual investment professional. The top three sectors based on each time horizon view metric are shaded green; the bottom three are shaded red. See Glossary and Methodology for details. It is not possible to invest directly in an index. All indexes are unmanaged. "New" indicates a changed strategist view since 9/30/23. Source: Haver Analytics, FactSet, Fidelity Investments, as of 12/31/23.

How much will previous rate hikes weigh down the economy?

It’s possible that the lagging impacts of recent policy interest-rate hikes, which boost borrowing costs, could tax economic growth this year. However, real (inflation-adjusted) interest rates rose only to about the middle of their historical range through the third quarter of 2023 (left). Also, higher rates tend to happen when the economy is healthy. Going back to 1935, real GDP growth has been stronger in 12-month periods after rates were higher, on average (right).

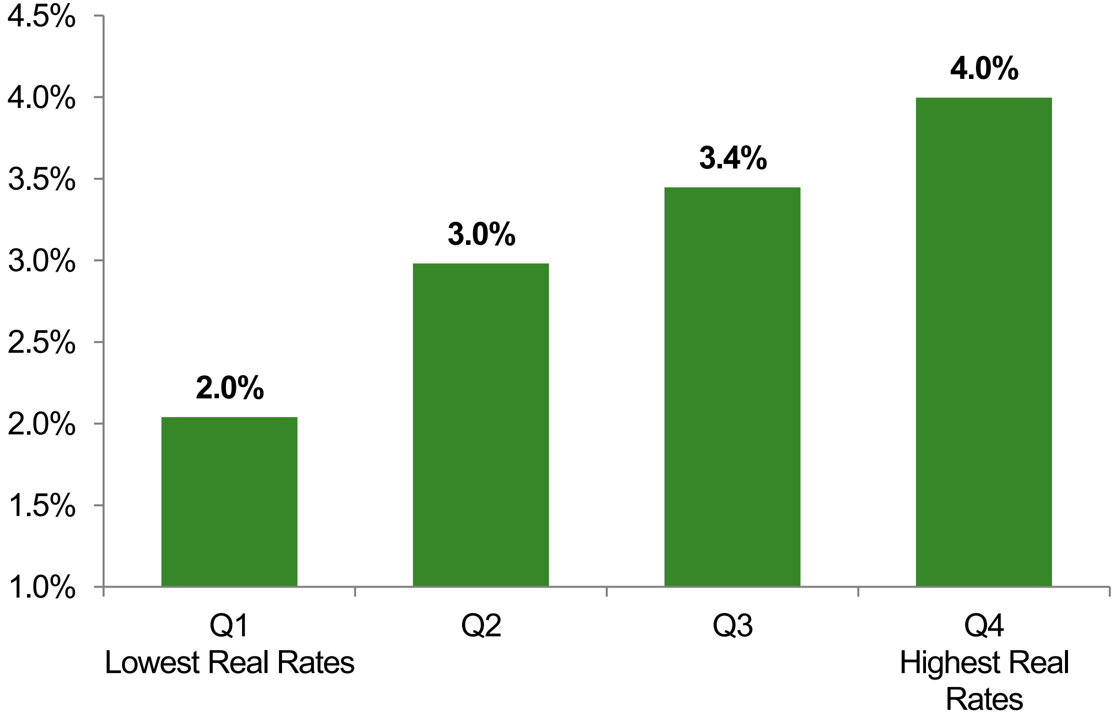
Real interest rates are in the middle of their historical range

Long-Term Treasury Composite Minus Trailing CPI, 1935–Present



Economic strength has followed higher rates

Average Real GDP Growth in Quartiles of Real Long Rates, 1935–Present.



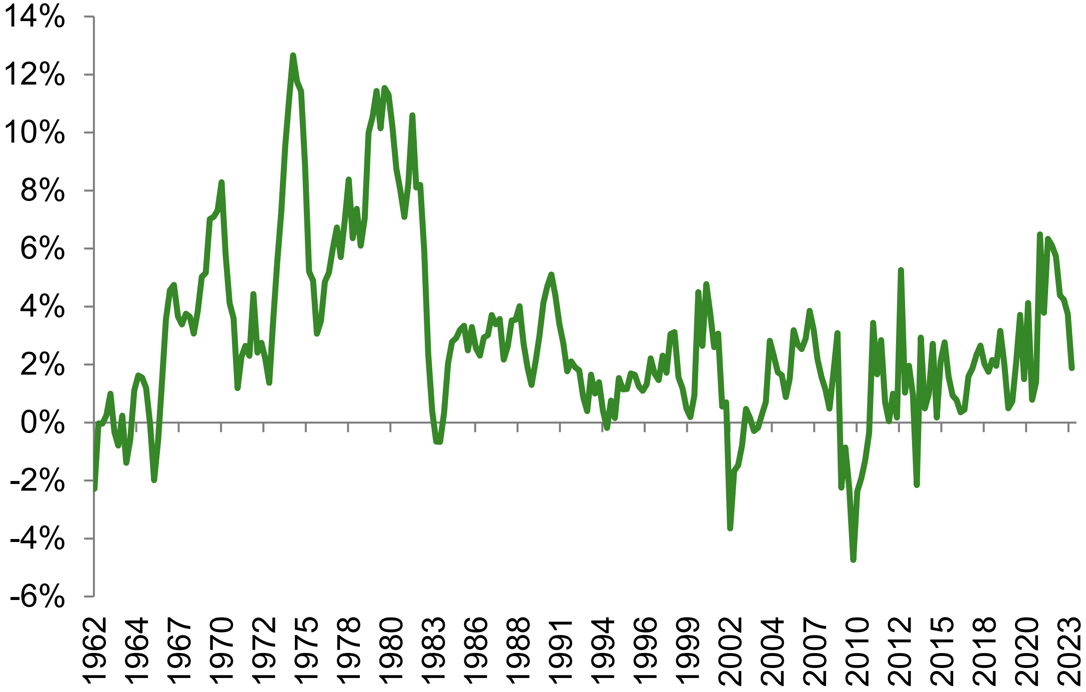
Past performance is no guarantee of future results. Sources: Haver Analytics, FactSet, Fidelity Investments, as of 9/30/2023. **LEFT**: CPI: Consumer Price Index. Real interest rates calculated as the average yield in Fidelity’s long-term Treasury composite index minus the 12-month change in the CPI. Data analyzed quarterly since December 1935. **RIGHT**: Real GDP growth calculated as nominal GDP growth minus the 12-month change in the CPI. Data analyzed quarterly since December 1935.

Falling unit labor costs have aided corporate profit margins

There's reason for optimism about corporate profit margins in 2024, partly due to the potential for increases in worker productivity. Unit labor costs—the price of the labor needed to produce one unit of output—slowed between June 2022 and September 2023 as productivity rose, reaching the bottom decile of its historical range since 1962 (left). When unit labor costs fell to comparable levels in the past, corporate operating margins grew an average of 6% over the next 12 months (right).

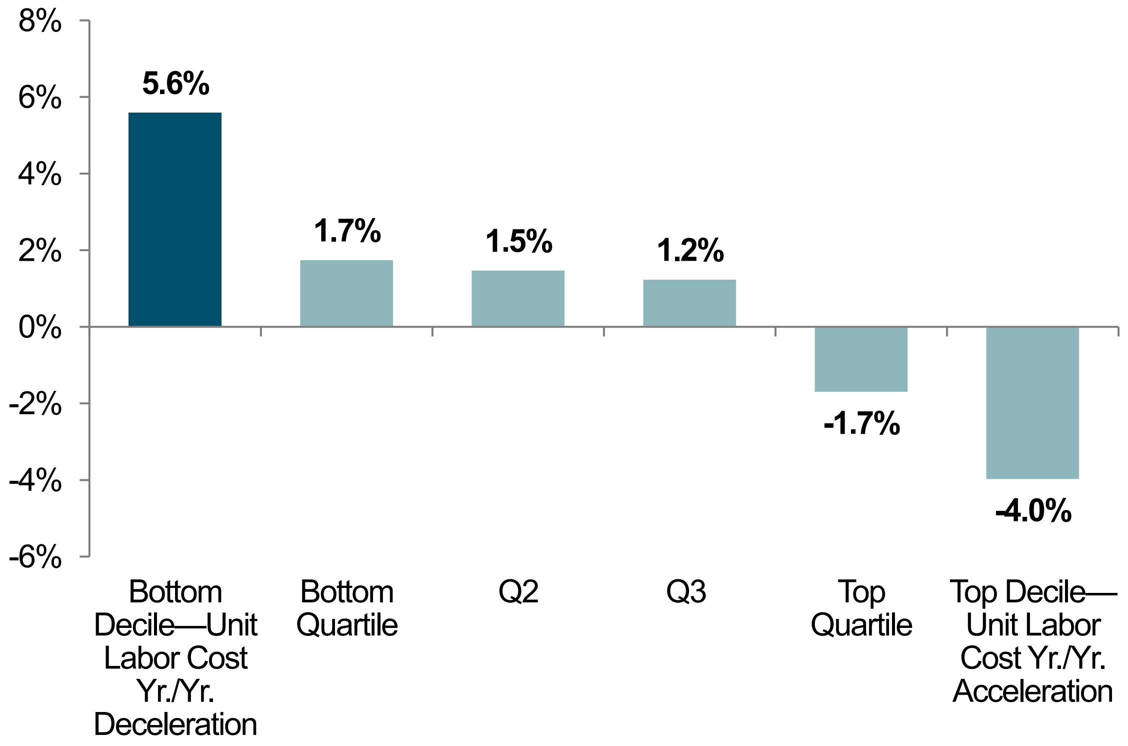
Unit labor cost growth slowed

Percent Year-to-Year Change in Nonfarm Business Sector Unit Labor Cost, 1962–Present



Decelerating unit labor costs benefited margins in the past

Average NTM Percent Change in Operating Margins in Quartiles & Deciles of LTM Acceleration of Unit Labor Costs, 1962–Present.



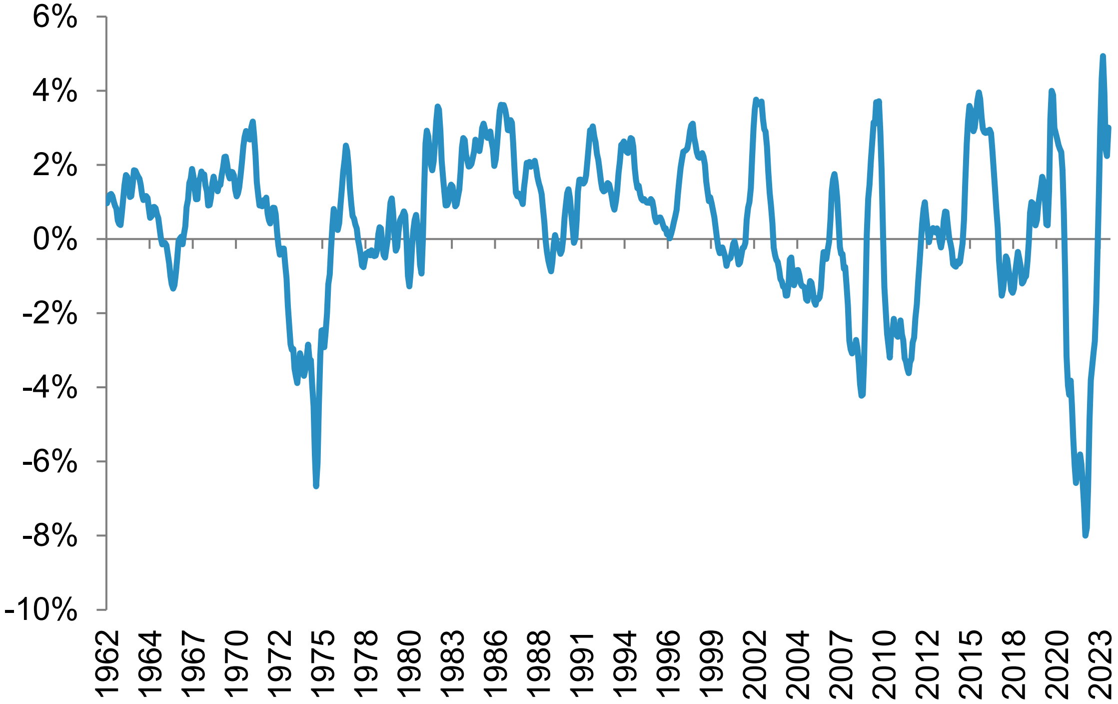
Past performance is no guarantee of future results. Data analyzed quarterly since January 1962. Analysis based on the S&P 500. Sources: Haver Analytics, FactSet, Fidelity Investments, as of 9/30/23. **RIGHT**: NTM: Next 12 months. LTM: Last 12 months. Yr/Yr is year-over year.

Margins rose when producer costs rose less than consumer prices

Here's another potential boon for earnings and profit margins: Consumer inflation has fallen a lot in recent months—and inflation for producers has come down even more (left). The difference between the two—with consumer inflation higher than producer inflation—recently reached its top decile, historically. Going back to 1962, corporate profit margins increased an average of 2.2% in the 12 months after similar top-decile gaps between these metrics (right).

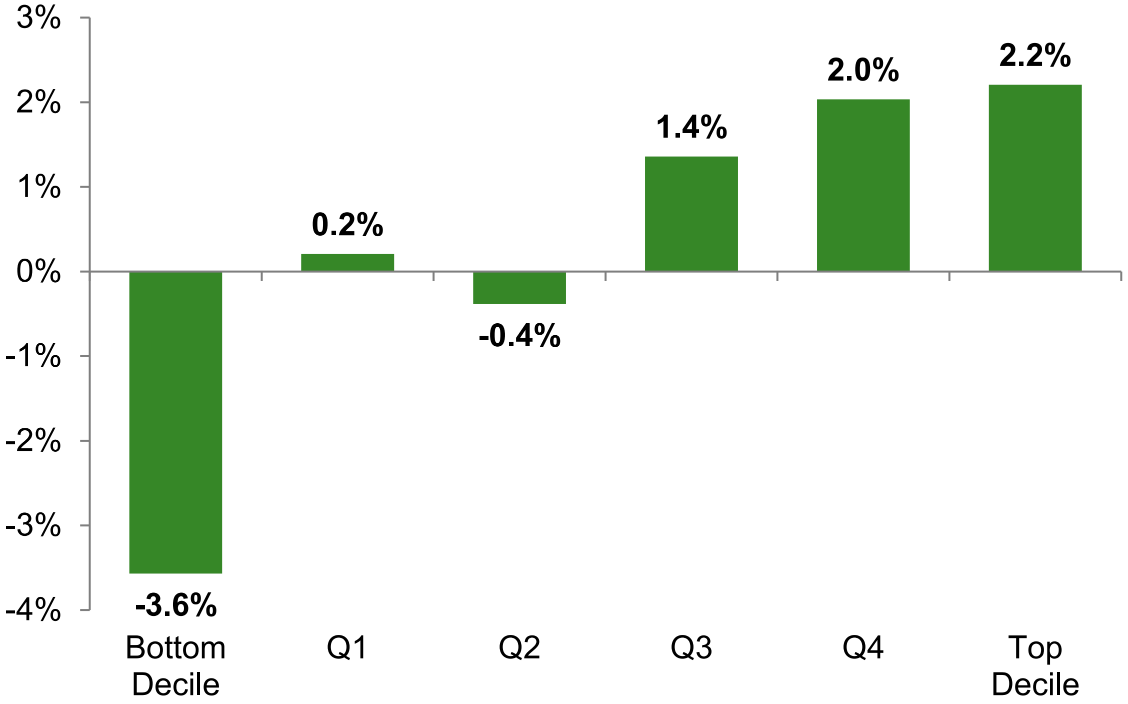
Inflation is higher for consumers than for producers

CPI All Items Year-Over-Year Minus PPI Finished Goods Year-Over-Year, 1962–Present



This has been good for margins in the past

NTM Change in Operating Margins By Cohort of Relative Consumer and Producer Inflation, 1962–Present



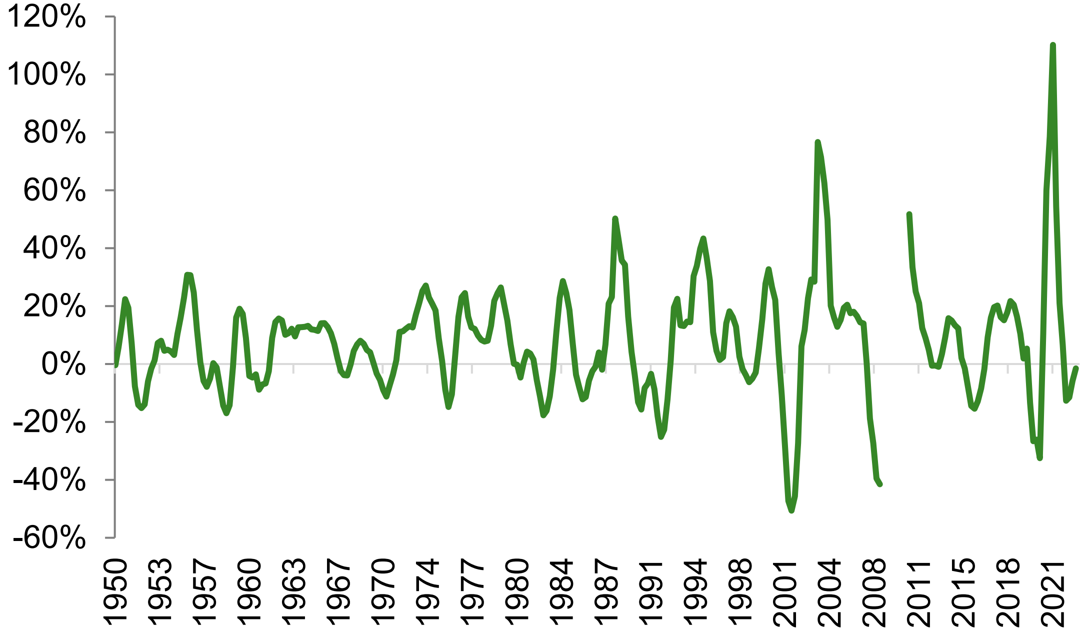
Past performance is no guarantee of future results. Analysis based on Fidelity top U.S. 3,000 stocks by market capitalization. Data analyzed monthly since January 1962. Sources: Haver Analytics, FactSet, Fidelity Investments, as of 10/30/23. **LEFT**: CPI: Consumer Price Index. PPI: Producer Price Index. PPI measures the average change over time in selling prices received by domestic producers of goods and services. **RIGHT**: For the given time frame, Q1 marks the worst quartile of operating margin change and Q4 marks the best.

Earnings recoveries historically boosted stocks

The drop in earnings growth since 2021 was comparable to those seen in recessions and the height of the pandemic (left). Analysts expect earnings growth to recover in 2024,* and earnings comebacks historically have been very good for investors: Between 1950 and September 2023, stocks gained an average of 16.2% during 12-month periods when earnings recovered after declining over the previous 12 months (right).

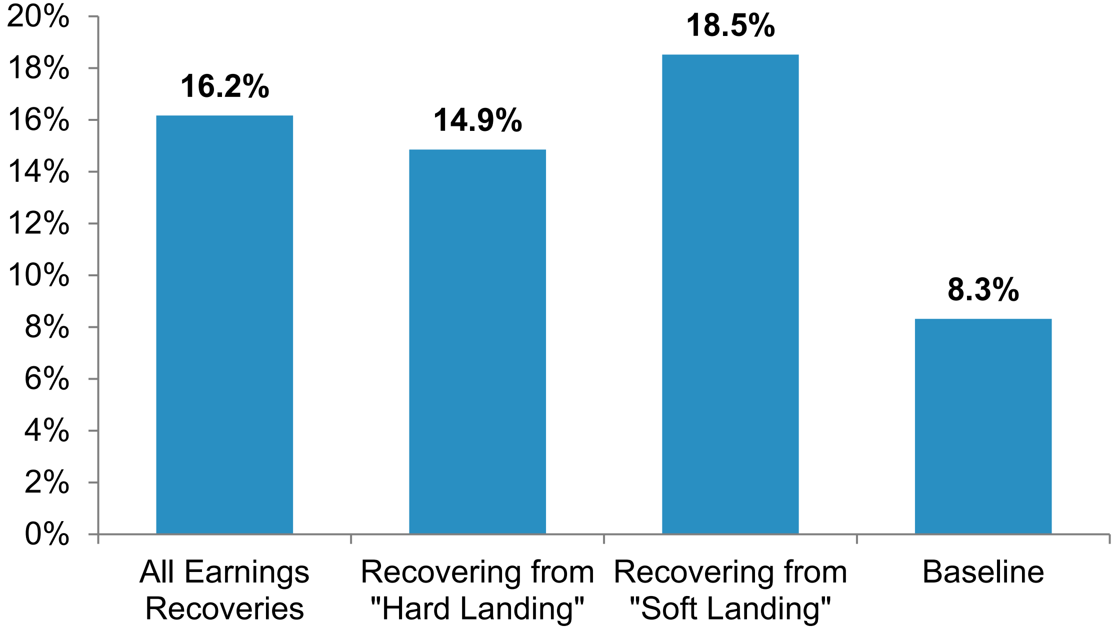
Earnings growth plummeted in recent years

Percent Year-to-Year Change in S&P 500 Composite Diluted Earnings, 1950–Present



Earnings recoveries have been good for stocks

Stock Returns During 12-Month Periods with Earnings Recoveries Versus Baseline, 1950–Present



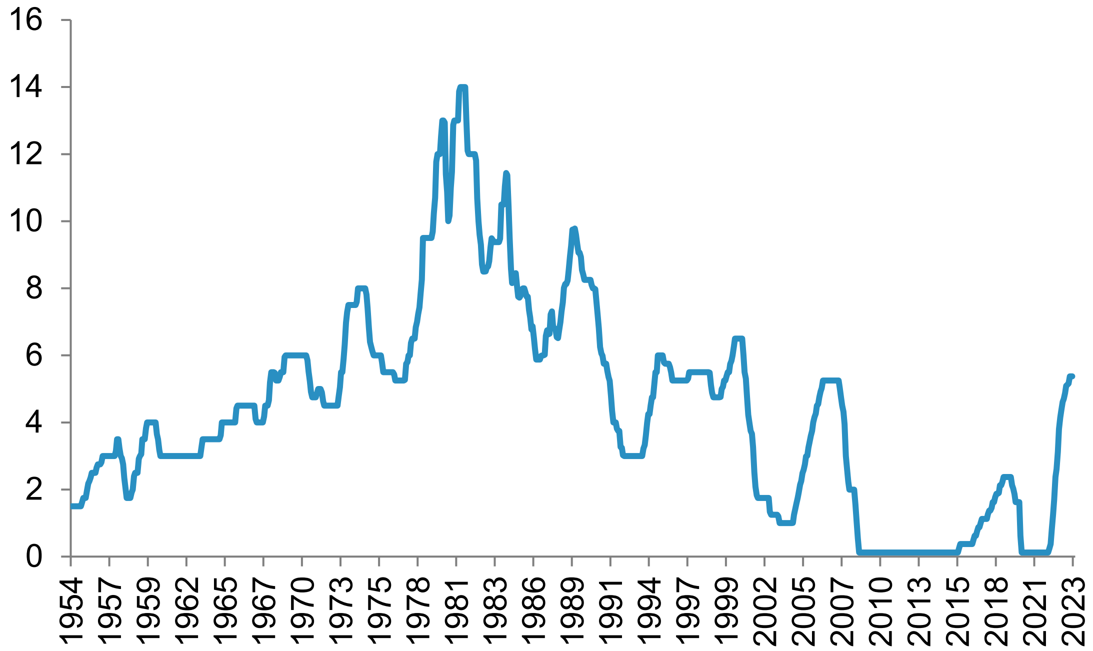
Past performance is no guarantee of future results. Data analyzed quarterly since January 1950. Analysis based on the S&P 500. * Earnings recovery expectation based on consensus analyst estimates of companies in the S&P 500 index (all analyst estimates for each company are amalgamated to compose an S&P 500 earnings growth rate). Recessions determined by the National Bureau of Economic Research (NBER) Business Cycle Dating Committee. **LEFT:** The chart excludes extreme data inputs around the time of the 2007–2009 Global Financial Crisis that would have distorted the chart. **RIGHT:** Hard landing refers to a cyclical economic slowdown associated with a recession. Soft landing refers to a cyclical economic slowdown that avoids a recession. Sources: Haver Analytics, FactSet, Fidelity Investments, as of 9/30/23.

How have stocks fared near the start of rate cuts?

After hiking interest rates since early 2022 (left), the U.S. Federal Reserve in December said it expects to start policy rate cuts in 2024. In the absence of recession, stocks have gained an average of 9% during the 12 months leading up to the first rate cut of a cycle and more than 12% the following 12 months (right). In the same periods with recessions, stocks fell 5%, on average, during the 12 months before the cut, then gained almost 14% over the following year.

Is the Fed done hiking?

Federal Open Market Committee Federal Funds Target Rate, July 1954–Present



First rate cuts have been good for stocks

12-Month Stock Returns Before and After First Rate Cuts, With or Without Recessions, July 1954–Present

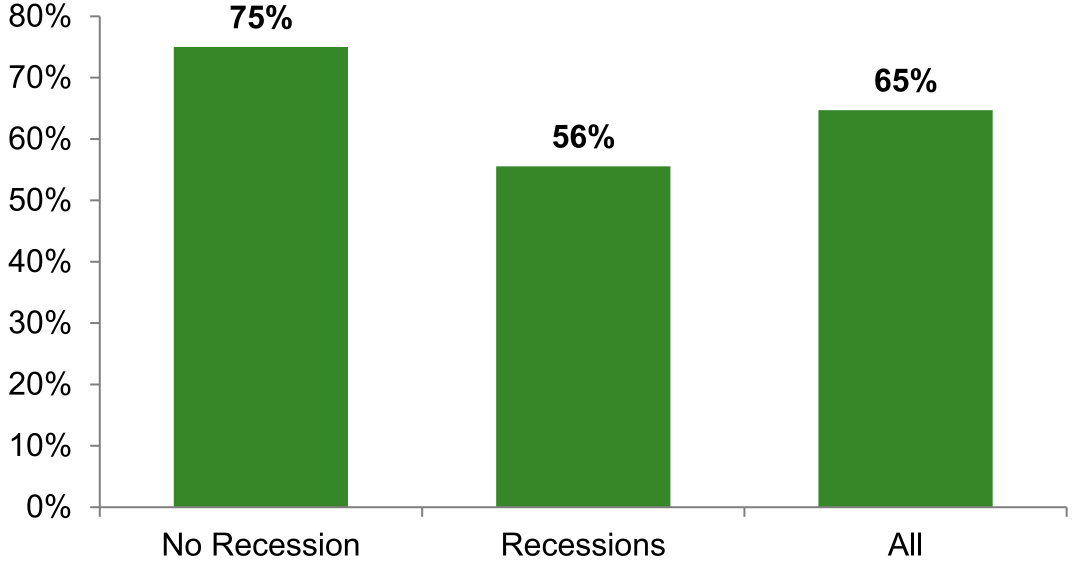
Past performance is no guarantee of future results. Data analyzed monthly since July 1954. Recessions determined by the National Bureau of Economic Research (NBER) Business Cycle Dating Committee. Sources: Haver Analytics, FactSet, Fidelity Investments, as of 10/31/23. **RIGHT**: Analysis based on the S&P 500.

Falling rates and accelerating earnings has benefited cyclicals

The yield on the 10-year Treasury note fell from 4.99% on October 19, 2023, to 3.98% in early January 2024. It's typical for bond yields to decline before the first rate cut of a cycle, especially in the absence of a recession (left). This is notable because yield declines coupled with earnings recoveries have helped cyclical stocks in the past: Going back to 1962, when 10-year yields fell and earnings accelerated, cyclicals outperformed the market (right).

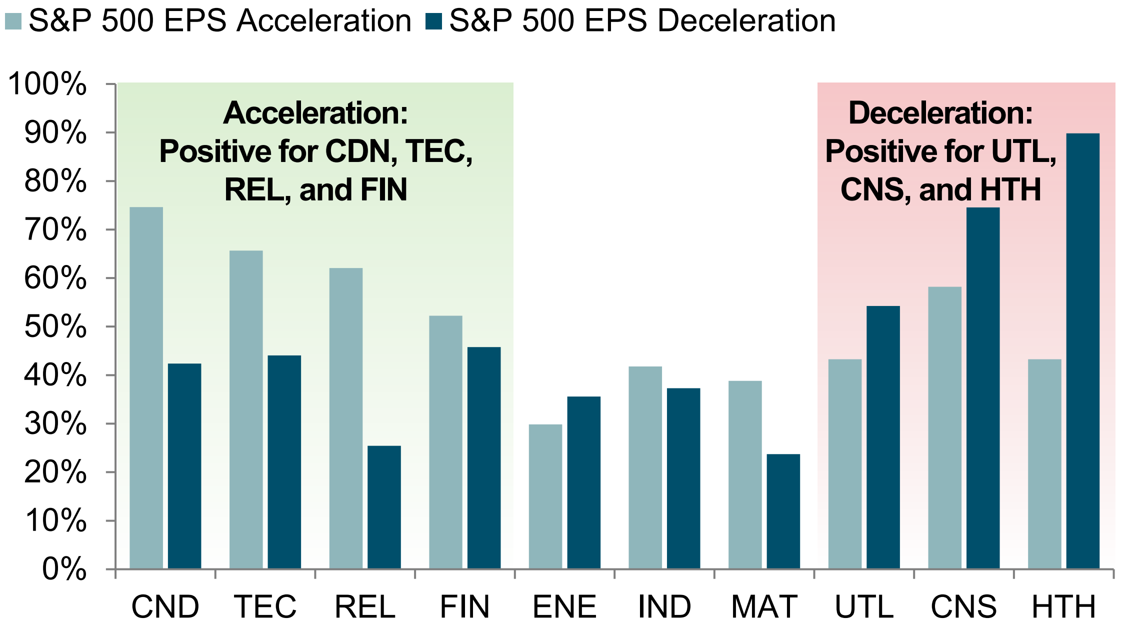
10-Year Treasury yields have fallen before first Fed cuts

Percent of Time 10-Year Yields Fell in Six Months Before Initial Rate Cuts, 1955–Present



Cyclicals outperformed when 10-year rates fell and earnings rose

Sector Relative Performance Odds, 10-Yr Rates Falling with Coincident Accelerating or Decelerating EPS Growth, Rolling 12M Periods, 1962–Present



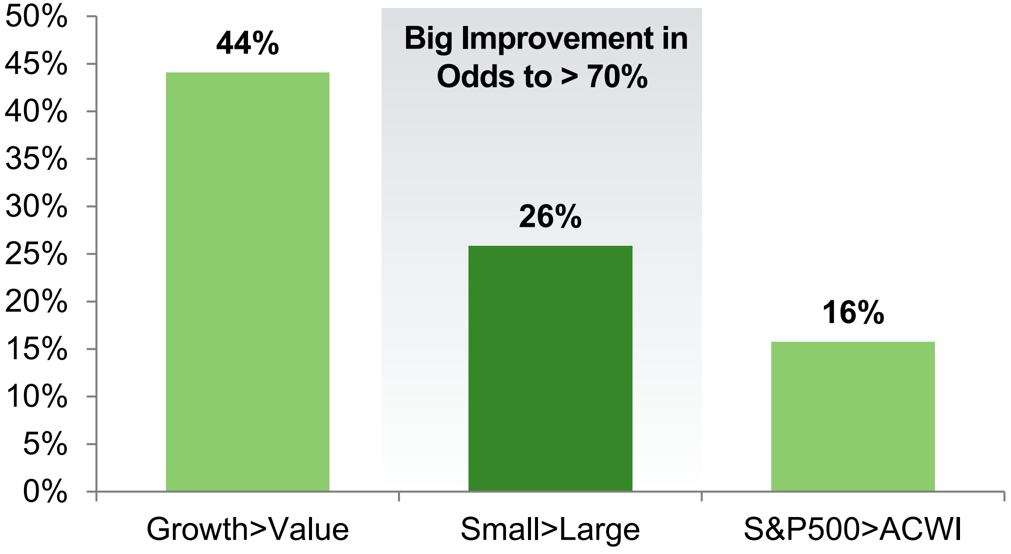
Past performance is no guarantee of future results. **LEFT**: Data analyzed monthly since July 1954. Sources: Haver Analytics, FactSet, Fidelity Investments, as of 10/31/23. **RIGHT**: CND: Consumer discretionary. TEC: Technology. REL: Real estate. FIN: Financials. ENE: Energy. IND: Industrials. MAT: Materials. UTL: Utilities. CNS: Consumer staples. HTH: Health care. EPS: Earning per share. Cyclical sectors include communication services, consumer discretionary, energy, financials, industrials, materials, real estate, and technology.
Defensive sectors include consumer staples, health care, and utilities. Data analyzed quarterly since January 1970. Analysis based on the S&P 500.
Recessions determined by the National Bureau of Economic Research (NBER) Business Cycle Dating Committee. Sources: Haver Analytics, FactSet, Fidelity Investments, as of 9/30/23.

Small caps have benefited in periods of falling rates and rising earnings

Early in 2024, the consensus calls for earnings to accelerate and policy interest rates to fall. In the past, this combination has tended to eventually lead to outperformance for small cap stocks. Going back to 1970, small caps outperformed large caps 76% of the time in the 12 months after earnings rose and rates fell (left). Also, the wide valuation spread within the small cap universe near the end of 2023 may be suggesting that the market has discounted a lot of bad news for smaller companies (right).

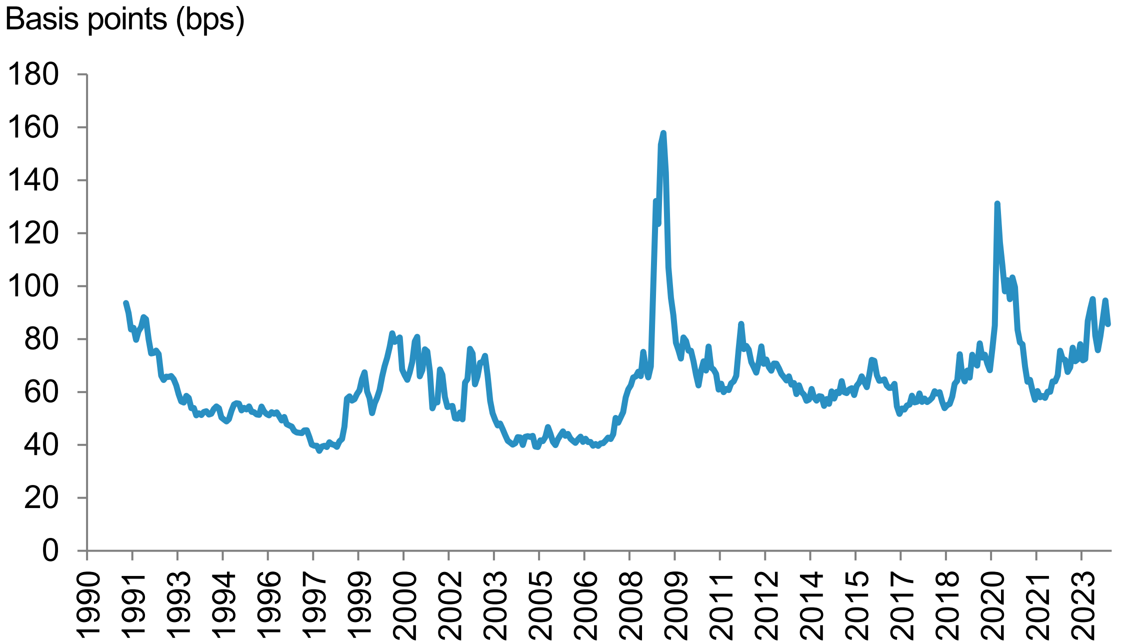
Faster earnings growth with lower rates has been meaningful for small caps

Increase in Odds of Small Caps Outperforming Large Caps 12 Months After Periods of Earnings Acceleration and Lower Rates vs. 12 Months After Periods of Earnings Deceleration and Higher Rates, 1970–Present



The market may be discounting fear in small caps

Spread between the Russell 2000's Highest and Lowest Book Yield Quartiles, April 1991–Present



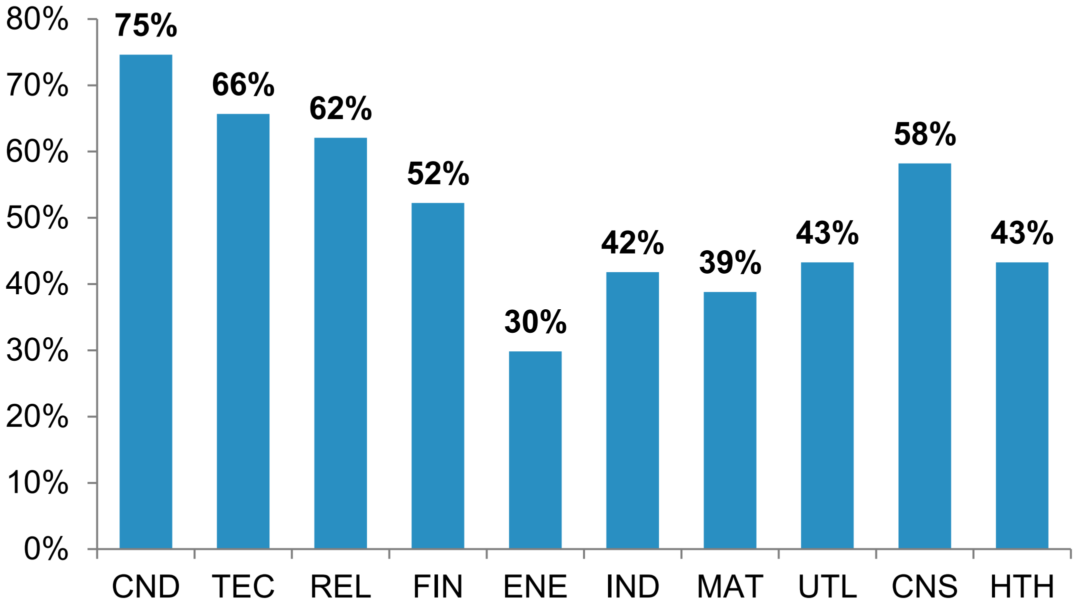
Past performance is no guarantee of future results. LEFT: Data analyzed quarterly since January 1970. Sources: Haver Analytics, FactSet, Fidelity Investments, as of 9/30/23. **RIGHT**: Valuation spread: The difference between the average book yield of the Russell 2000's most-expensive and least-expensive quartiles. Data analyzed monthly since April 1991. Analysis based on Fidelity top U.S. 3,000 stocks by market capitalization. Sources: Haver Analytics, FactSet, Fidelity Investments, as of 11/30/23.

Falling rates and rising earnings have helped other sectors too

Since 1970, the consumer discretionary, technology, and real estate sectors have had the best odds of outperforming the market for the 12-month periods in which interest rates fell and earnings accelerated (left). Over the same time frame, the real estate sector's odds of outperformance improved the most compared with 12-month periods of rising rates and falling earnings (right).

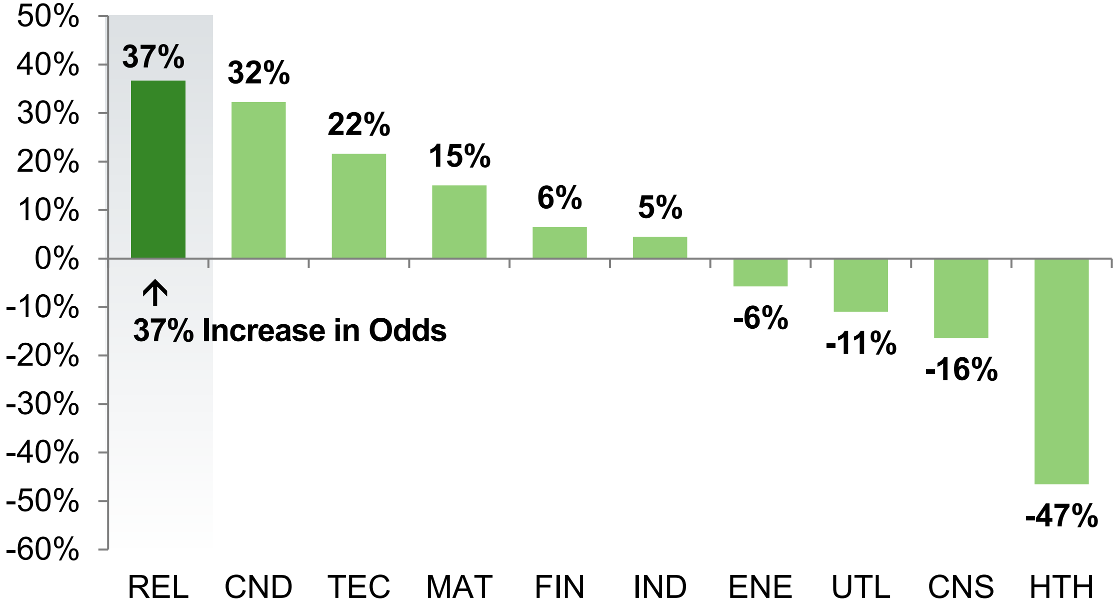
Cyclicals outperformed when rates fell, earnings rose

Sector Relative Performance Odds When 10-Year Rates Fell and S&P 500 Earning Growth Accelerated, Rolling 12-Month Periods, 1970–Present



Real estate's odds of outperformance improved most of any sector when moving to periods of lower rates and faster EPS

Odds of Outperformance by Sector in Periods of Lower Rates, Accelerating EPS, compared with Periods of Rising Rates and Slowing EPS, 1970–Present



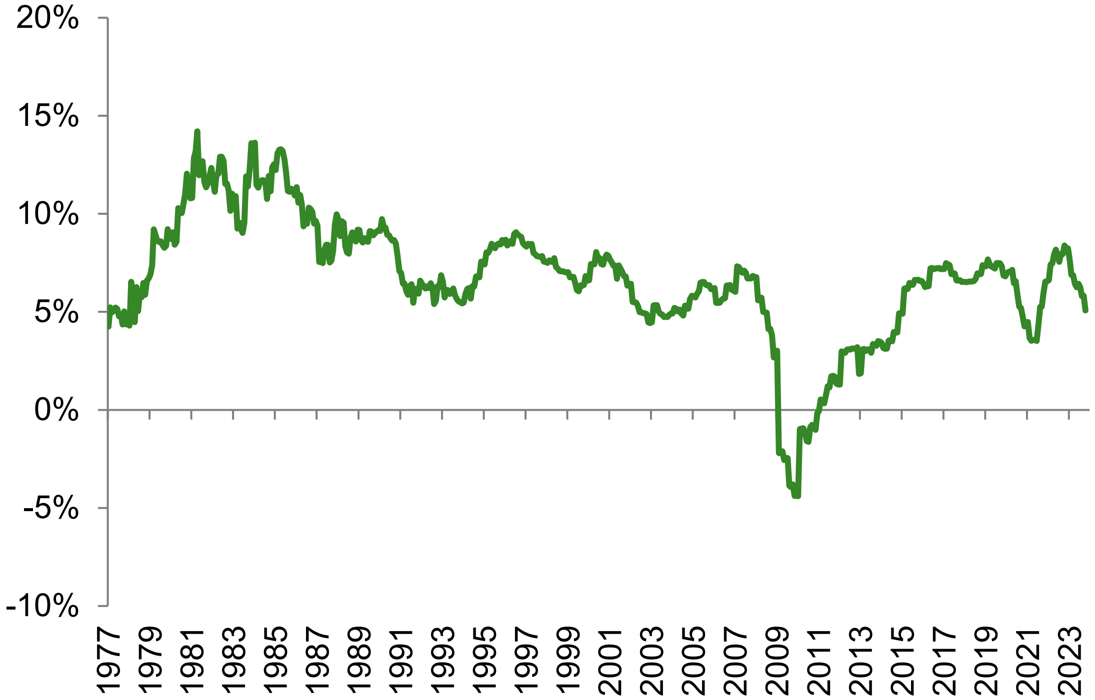
Past performance is no guarantee of future results. Cyclical sectors include communication services, consumer discretionary, energy, financials, industrials, materials, real estate, and technology. CND: Consumer discretionary. TEC: Technology. REL: Real estate. FIN: Financials. ENE: Energy. IND: Industrials. MAT: Materials. UTL: Utilities. CNS: Consumer staples. HTH: Health care. Data analyzed quarterly since January 1970. Analysis based on the S&P 500. Sources: Haver Analytics, FactSet, Fidelity Investments, as of 9/30/23. RIGHT: EPS: Earnings per share.

Bad ROEs have been good for real estate outperformance

Real estate lagged the market in 2023 and the sector's return on equity (ROE) recently reached the bottom quartile of its historical range (left). Going back to 1977, this has been good news for the sector's future relative performance. After real estate's ROE hit bottom-quartile levels in the past, the sector outperformed the market by an average of 4.59% over the next 12 months (right)—possibly because the market had priced in a lot of bad news by then.

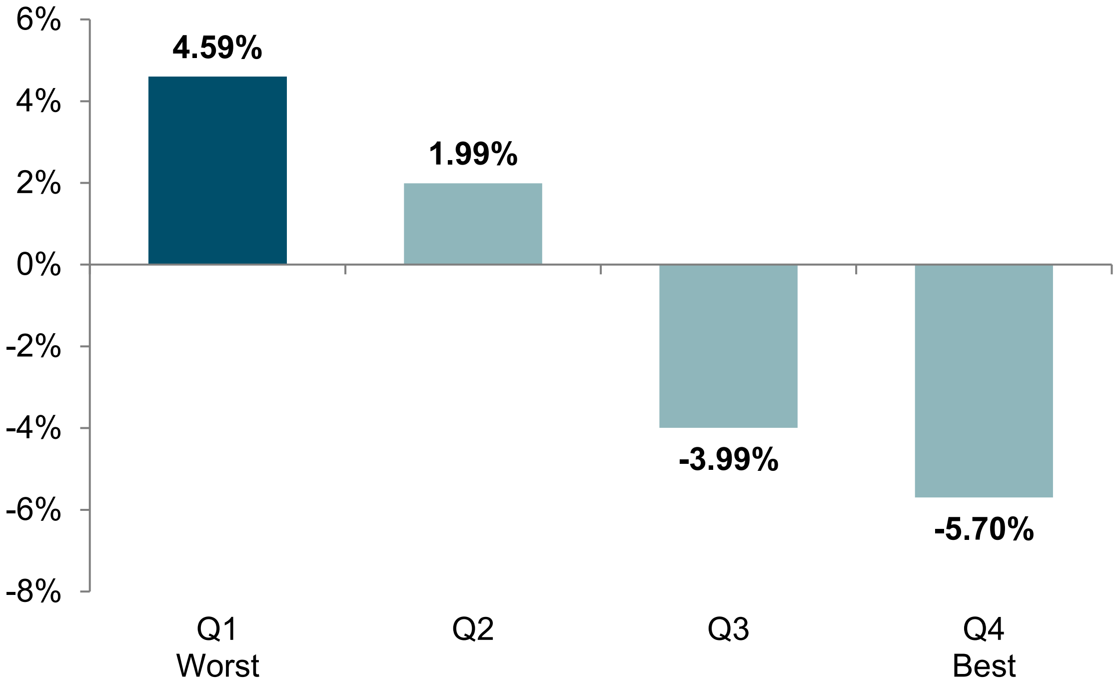
Real estate fundamentals have been weak

Real Estate Return on Equity, 1977–Present



Real estate has outperformed after bottom-quartile ROEs

Real Estate NTM Relative Performance from ROE Quartiles, 1977–Present



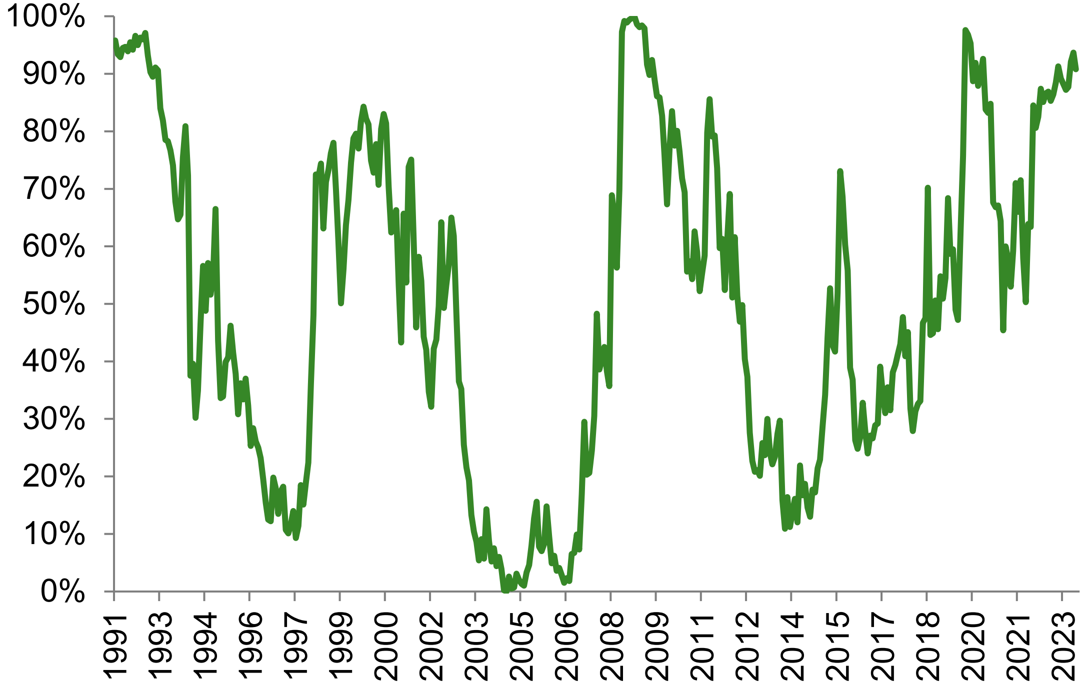
Past performance is no guarantee of future results. ROE: Return on equity. Data analyzed monthly since January 1977. Analysis based on Fidelity top U.S. 3,000 stocks by market capitalization. **RIGHT:** NTM = next 12 months. Sources: Haver Analytics, FactSet, Fidelity Investments, as of 10/31/23.

High real estate valuation spreads have been bullish

A wide range of prices for stocks within a sector can sometimes be a bullish signal. As of the end of 2023, valuation spreads in the real estate sector stood within the top decile of their historical range based on price-to-book value (left). This may suggest investors have low expectations for the sector. Since 1991, real estate stocks beat the market over the next 12 months 83% of the time when the sector reached top-decile valuation spreads (right).

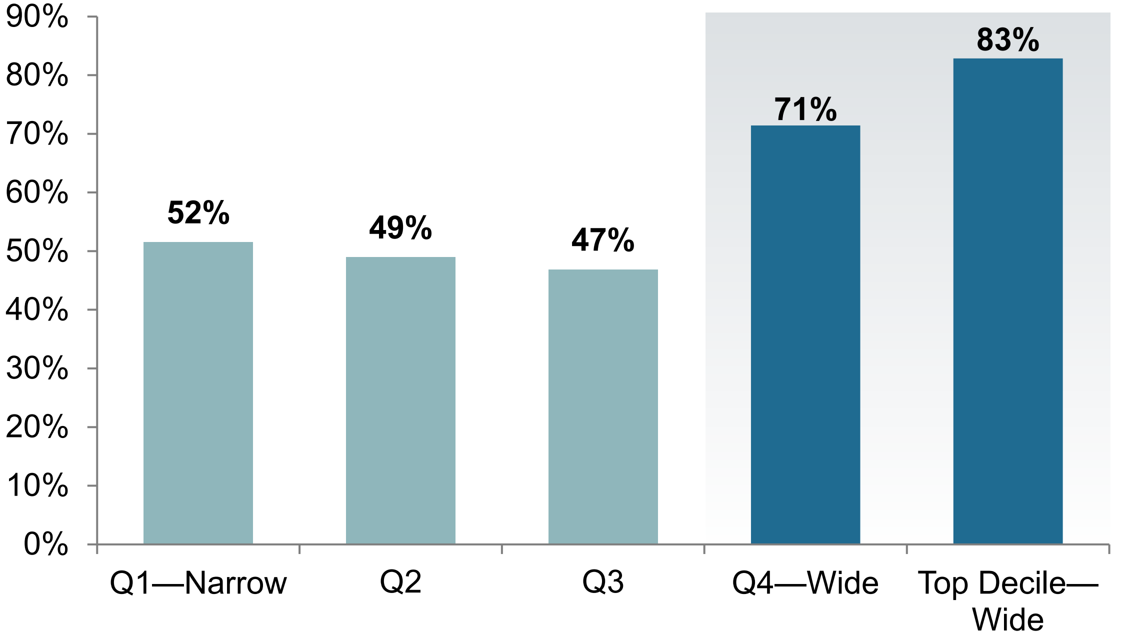
Real estate valuation spreads are historically high

Percentile Rank of Price-to-Book Spread Versus History, December 1991–Present



Larger valuation spreads have increased real estate's outperformance odds

Real Estate Relative Odds of NTM Outperformance in Quartiles and Top Decile of Book Valuation Spreads, December 1991–Present



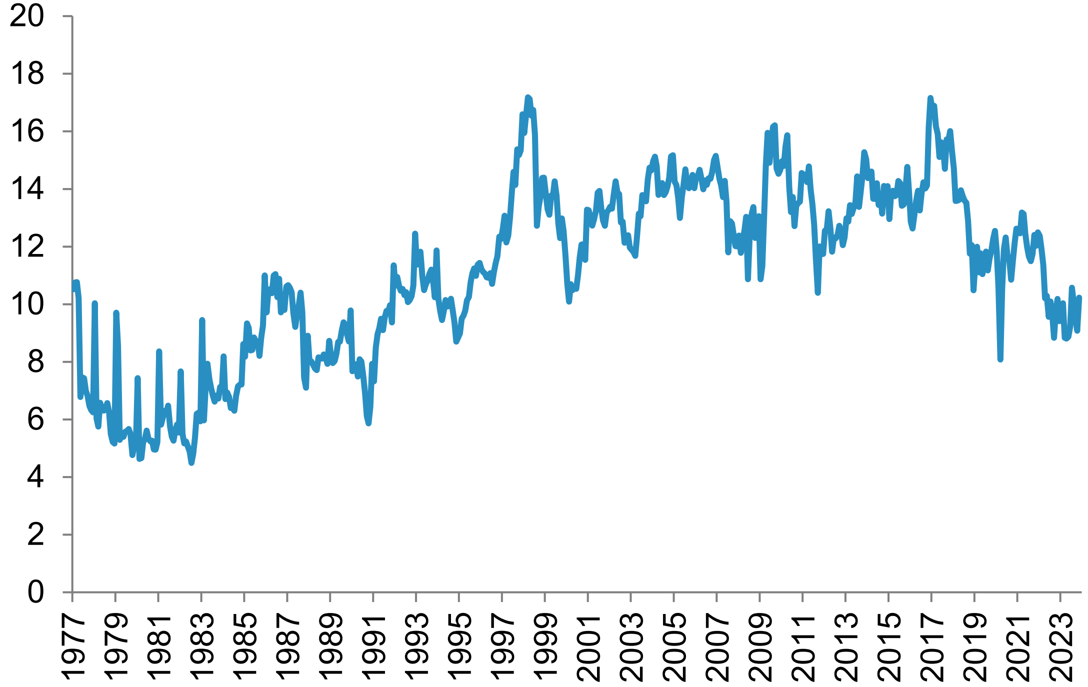
Past performance is no guarantee of future results. Data analyzed monthly since December 1991. Analysis based on Fidelity top U.S. 3,000 stocks by market capitalization. Valuation spread: The difference between the average price-to-book of the most-expensive and least-expensive quartiles. Sources: Haver Analytics, FactSet, Fidelity Investments, as of 11/30/23. **RIGHT**: NTM: Next twelve months. Narrow = the quartile of narrowest book valuation spreads over the given period. Wide = the quartile and decile of widest book valuation spreads, respectively.

Financials trade at low valuations, historically a bullish sign

Valuations within the financials sector recently reached extremes as well, and the sector appears historically inexpensive. Going back to 1977, financial stocks are priced in the bottom quartile of their range based on a median forward price-to-earnings ratio (left). Historically, the cheaper the financial sector has been, the better its odds of outperformance over the next 12 months—especially when interest rates fell (right).

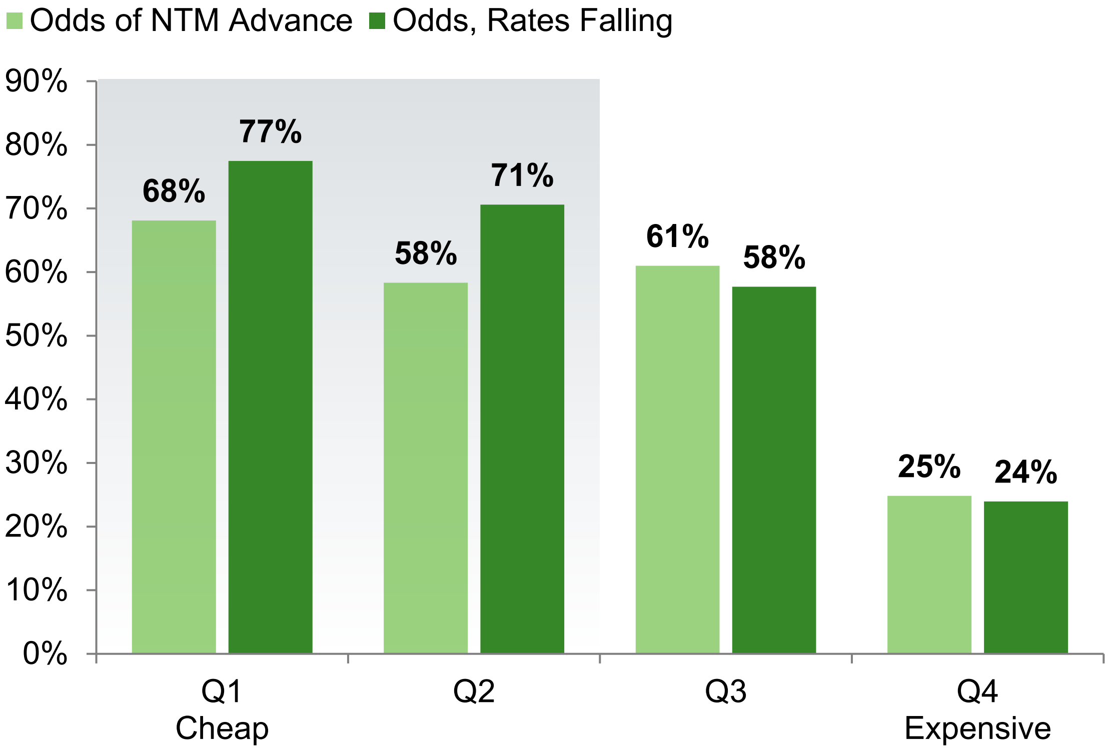
Financials are historically cheap

Median Forward P/E Ratio for Financials, 1977–Present



Financials have outperformed, on average, following low valuations

Odds of Financials Outperformance in Quartiles of Forward P/E, 1977–Present



Past performance is no guarantee of future results. Fwd P/E: Forward price-to-earnings ratio. A forward P/E ratio typically uses an average of analysts' published earnings estimates for the next 12 months. Data analyzed monthly since January 1977. Analysis based on Fidelity top U.S. 3,000 stocks by market capitalization. Sources: Haver Analytics, FactSet, Fidelity Investments, as of 11/30/23. **RIGHT**: NTM: Next 12 months.

Glossary and methodology

Glossary

Cycle Hit Rate: Calculates the frequency of a sector outperforming the broader equity market over each business cycle phase since 1962.

Dividend Yield: Annual dividends per share divided by share price.

Earnings before Interest, Taxes, Depreciation, and Amortization (EBITDA): A non-GAAP measure often used to compare profitability between companies and industries, because it eliminates the effects of financing and accounting decisions.

Earnings-per-Share Growth: Measures the growth in reported earnings per share over the specified past time period.

Earnings Yield: Earnings per share divided by share price. It is the inverse of the price-to-earnings (P/E) ratio.

Enterprise Value: A measure of a company's total value that includes its market capitalization as well as short- and long-term debt and cash on its balance sheet.

Free Cash Flow (FCF): The amount of cash a company has remaining after expenses, debt service, capital expenditures, and dividends. High free cash flow typically suggests stronger company value.

Free-Cash-Flow Margin: The amount of free cash flow as a percentage of revenue. High FCF margin often denotes strong profitability.

Free-Cash-Flow Yield: Free cash flow per share divided by share price. A high FCF yield often represents a good investment opportunity, because investors would be paying a reasonable price for healthy cash earnings.

Full-Phase Average Performance: Calculates the (geometric) average performance of a sector in a particular phase of the business cycle and subtracts the performance of the broader equity market.

Median Monthly Difference: Calculates the difference in the monthly performance of a sector compared with the broader market, and then takes the midpoint of those observations.

Price-to-Book (P/B) Ratio: The ratio of a company's share price to reported accumulated profits and capital.

Price-to-Earnings (P/E) Ratio: The ratio of a company's current share price to its reported earnings. A forward P/E ratio typically uses an average of analysts' published earnings estimates for the next 12 months.

Price-to-Sales (P/S) Ratio: The ratio of a company's current share price to reported sales.

Relative Strength: The comparison of a security's performance relative to a benchmark, typically a market index.

Return on Equity (ROE): The amount, expressed as a percentage, earned on a company's common stock investment for a given period.

Risk Decomposition: A mathematical analysis that estimates the relative contribution of various sources of volatility.

Methodology

Strategist View: Our sector strategist, Denise Chisholm, tracks key indicators that have influenced the historical likelihood of outperformance of each sector. This historical probability analysis informs the Strategist Views.

Fundamentals: Sector rankings are based on equally weighting the following four fundamental factors: EBITDA growth, earnings growth, ROE, and FCF margin. However, we evaluate the financials and real estate sectors only on earnings growth and ROE because of differences in their business models and accounting standards.

Relative Strength: Compares the strength of a sector versus the S&P 500 index over a six-month period, with a one-month reversal on the latest month; identifying relative strength patterns can be a useful indicator of short-term sector performance.

Relative Valuations: Valuation metrics for each sector are relative to the S&P 500. Ratios compute the current relative valuation divided by the 10-year historical average relative valuation, eliminating the top 5% and bottom 5% values to reduce the effect of potential outliers. Sectors are then ranked by their weighted average ratios, weighted as follows: P/E: 37%; P/B: 21%; P/S: 21%; and FCF yield: 21%. However, the financials and real estate sectors are weighted as follows: P/E: 65% and P/B: 35%.

Appendix

Information presented herein is for discussion and illustrative purposes only and is not a recommendation or an offer or a solicitation to buy or sell any securities. Views expressed are as 12/31/23, based on the information available at that time, and may change based on market and other conditions. Unless otherwise noted, the opinions provided are those of the authors and not necessarily those of Fidelity Investments or its affiliates. Fidelity does not assume any duty to update any of the information.

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This piece may contain assumptions that are "forward-looking statements," which are based on certain assumptions of future events. Actual events are difficult to predict and may differ from those assumed. There can be no assurance that forward-looking statements will materialize or that actual returns or results will not be materially different from those described here.

Past performance is no guarantee of future results.

Investing involves risk, including risk of loss.

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Appendix

Sectors are defined as follows: **Communication Services:** companies that facilitate communication or provide access to entertainment content and other information through various types of media. **Consumer Discretionary:** companies that provide goods and services that people want but don't necessarily need, such as televisions, cars, and sporting goods; these businesses tend to be the most sensitive to economic cycles. **Consumer Staples:** companies that provide goods and services that people use on a daily basis, like food, household products, and personal-care products; these businesses tend to be less sensitive to economic cycles. **Energy:** companies whose businesses are dominated by either of the following activities: the construction or provision of oil rigs, drilling equipment, or other energy-related services and equipment, including seismic data collection; or the exploration, production, marketing, refining, and/or transportation of oil and gas products, coal, and consumable fuels. **Financials:** companies involved in activities such as banking, consumer finance, investment banking and brokerage, asset management, and insurance and investments. **Health Care:** companies in two main industry groups: health care equipment suppliers and manufacturers, and providers of health care services; and companies involved in the research, development, production, and marketing of pharmaceuticals and biotechnology products. **Industrials:** companies whose businesses manufacture and distribute capital goods, provide commercial services and supplies, or provide transportation services. **Materials**: companies that are engaged in a wide range of commodity-related manufacturing. **Real Estate:** companies in two main industry groups—real estate investment trusts (REITs), and real estate management and development companies. **Technology:** companies in technology software and services and technology hardware and equipment. **Utilities:** companies considered to be electric, gas, or water utilities, or companies that operate as independent producers and/or distributors of power.

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171 FERC ¶ 61,154
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Neil Chatterjee, Chairman;
Richard Glick, Bernard L. McNamee,
and James P. Danly.

Association of Businesses Advocating Tariff Equity Coalition of MISO Transmission Customers Illinois Industrial Energy Consumers Indiana Industrial Energy Consumers, Inc. Minnesota Large Industrial Group Wisconsin Industrial Energy Group	Docket No. EL14-12-004

v.

Midcontinent Independent System Operator, Inc.
ALLETE, Inc.
Ameren Illinois Company
Ameren Missouri
Ameren Transmission Company of Illinois
American Transmission Company LLC
Cleco Power LLC
Duke Energy Business Services, LLC
Entergy Arkansas, Inc.
Entergy Gulf States Louisiana, LLC
Entergy Louisiana, LLC
Entergy Mississippi, Inc.
Entergy New Orleans, Inc.
Entergy Texas, Inc.
Indianapolis Power & Light Company
International Transmission Company
ITC Midwest LLC
Michigan Electric Transmission Company, LLC
MidAmerican Energy Company
Montana-Dakota Utilities Co.
Northern Indiana Public Service Company
Northern States Power Company-Minnesota
Northern States Power Company-Wisconsin
Otter Tail Power Company
Southern Indiana Gas & Electric Company

Arkansas Electric Cooperative Corporation
Mississippi Delta Energy Agency
Clarksdale Public Utilities Commission
Public Service Commission of Yazoo City
Hoosier Energy Rural Electric Cooperative, Inc.

Docket No. EL15-45-013

v.

ALLETE, Inc.
Ameren Illinois Company
Ameren Missouri
Ameren Transmission Company of Illinois
American Transmission Company LLC
Cleco Power LLC
Duke Energy Business Services, LLC
Entergy Arkansas, Inc.
Entergy Gulf States Louisiana, LLC
Entergy Louisiana, LLC
Entergy Mississippi, Inc.
Entergy New Orleans, Inc.
Entergy Texas, Inc.
Indianapolis Power & Light Company
International Transmission Company
ITC Midwest LLC
Michigan Electric Transmission Company, LLC
MidAmerican Energy Company
Montana-Dakota Utilities Co.
Northern Indiana Public Service Company
Northern States Power Company-Minnesota
Northern States Power Company-Wisconsin
Otter Tail Power Company
Southern Indiana Gas & Electric Company

OPINION NO. 569-A

ORDER ON REHEARING

(Issued May 21, 2020)

1. On November 21, 2019, the Commission issued Opinion No. 569.[1] In that order, the Commission acted on the then-pending rehearing requests and the Initial Decision, as well the Order Directing Briefs,[2] in the above-captioned proceedings. In brief, Opinion No. 569 applied a revised methodology for analyzing the base return on equity (ROE) component of public utility rates under section 206 of the Federal Power Act (FPA) that used the discounted cash flow (DCF) model and capital-asset pricing model (CAPM), instead of only the DCF model, and established a range of presumptively just and reasonable ROEs based on the quartiles of the zone of reasonableness. Multiple parties request rehearing of Opinion No. 569.[3] In this order, we grant in part and deny in part the requests for rehearing.

2. In particular, in Opinion No. 569, the Commission used the DCF model and CAPM in its determinations under the first and second prongs of section 206, giving each model equal weight under both prongs, and did not use the expected earnings (Expected Earnings) or risk premium (Risk Premium) models, as proposed in the Briefing Order. In addition, the Commission used the ranges of presumptively just and reasonable ROEs in its analysis under the first prong of section 206, as the Commission proposed in the Briefing Order, used the high-end outlier test as proposed in the Briefing Order, used the Institutional Brokers' Estimate System (IBES) as the source of short-term earnings growth estimates in the DCF and CAPM, and used a revised low-end outlier test that eliminates DCF and CAPM proxy group ROE results that are less than the yields of generic corporate Baa bonds plus 20% of the CAPM risk premium. In this order, we are granting rehearing of Opinion No. 569 to use the Risk Premium model under both prongs of our section 206 analysis, to give the short-term growth rate 80% weighting and the long-term growth rate 20% weighting in the two-step DCF model, to modify the high-end outlier test to treat any proxy company as high-end outlier if its cost of equity estimated under the model in question is more than 200% of the median result of all of the potential proxy group members in that model[4] before any high or low-end outlier test is applied, subject to a "natural break" analysis, to consider the use of *Value Line* short-term earnings growth estimates in the CAPM in future proceedings, and to calculate the ranges

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[1] *Ass'n of Bus. Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.*, Opinion No. 569, 169 FERC ¶ 61,129 (2019).

[2] *Ass'n of Bus. Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.*, 165 FERC ¶ 61,118 (2018) (Briefing Order).

[3] *See infra* PP 23-24.

[4] As noted below, the high-end outlier test only applies to the DCF model and CAPM because they utilize results of the relevant analysis applied to a proxy group, while the Risk Premium model is derived from actual ROEs.

of presumptively just and reasonable base ROEs by dividing the overall composite zone of reasonableness into equal thirds.

3. Applying this revised methodology to the facts of the November 12, 2013, complaint filed in Docket No. EL14-12-000 pursuant to section 206 (First Complaint), we review the Midcontinent Independent System Operator, Inc. (MISO) transmission-owning members' (MISO TOs) 12.38% base ROE that was the existing ROE reviewed in Opinion No. 551, which was pending on rehearing before the Commission when it issued Opinion No. 569, and continue to find that this base ROE is unjust and unreasonable. Having found that MISO TOs' 12.38% ROE is unjust and unreasonable, we then find that a just and reasonable replacement ROE for the MISO TOs in the First Complaint proceeding is 10.02%. As discussed further below, in the second section 206 complaint (Second Complaint) proceeding in Docket No. EL15-45-000, the ROE to be reviewed is the 10.02% base ROE established in the First Complaint proceeding that is effective prospectively from September 28, 2016—the date of the issuance of Opinion No. 551. Under the revised base ROE methodology applied in this order, the 10.02% base ROE that the Commission is reviewing for purposes of the Second Complaint proceeding falls within the applicable range of presumptively just and reasonable base ROEs, therefore, the Commission presumes it to be just and reasonable. As discussed below, we find that this presumption has not been rebutted by the evidence in the Second Complaint proceeding. Accordingly, we affirm the Commission's decision in Opinion No. 569 to dismiss the Second Complaint, and its finding that no refunds should be issued as a result of the resolution of that complaint.

I. Background

A. Opinion No. 531 *et seq.*

4. In Opinion No. 531, the Commission adopted certain changes to its use of the DCF methodology for evaluating and setting the Commission-allowed ROE for the New England transmission owners (New England TOs). In particular, the Commission elected to replace the "one-step" DCF model, which considers only short-term growth projections for a public utility, with a "two-step" model that considers both short- and long-term growth projections.[5] The Commission also departed from its typical practice of setting the just and reasonable ROE of a group of utilities at the midpoint of the zone of reasonableness. The Commission explained that evidence of "anomalous" capital

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[5] *See generally Coakley Mass. Attorney Gen. v. Bangor Hydro-Elec. Co.*, Opinion No. 531, 147 FERC ¶ 61,234, at PP 8, 32-41, *order on paper hearing*, Opinion No. 531-A, 149 FERC ¶ 61,032 (2014), *order on reh'g*, Opinion No. 531-B, 150 FERC ¶ 61,165 (2015), *rev'd, Emera Maine v. FERC*, 854 F.3d 9 (D.C. Cir. 2017) (*Emera Maine*).

market conditions, including "bond yields [that were] at historic lows," made the Commission "less confiden[t] that the midpoint of the zone of reasonableness . . . accurately reflects the [ROE] necessary to meet the *Hope* and *Bluefield* capital attraction standards."[6] The Commission therefore looked to four alternative benchmark models: three financial models—the Risk Premium model, CAPM, and Expected Earnings model[7]—as well as a comparison with the ROEs approved by state public utility commissions.[8] In considering those models, the Commission emphasized that it was not departing from its long-standing reliance on the DCF model, but rather relying on those models only to "inform the just and reasonable placement of the ROE within the zone of reasonableness established . . . by the DCF methodology."[9] Based on these alternative models, the Commission determined that an ROE of 10.57%, the midpoint of the upper half of the zone of reasonableness produced by the two-step DCF model, would be just and reasonable. Because that figure differed from New England TOs' existing 11.14% ROE, the Commission concluded that the existing base ROE had become unjust and unreasonable and it therefore set New England TOs' base ROE at 10.57%, pending a paper hearing concerning the long-term growth projection to use in the DCF analysis. Following that hearing, in Opinion No. 531-A the Commission reaffirmed its conclusion that New England TOs' existing ROE was unjust and unreasonable and that 10.57% was the just and reasonable ROE. The Commission required New England TOs to submit a compliance filing to implement their new ROEs effective October 16, 2014—the date of issuance of Opinion No. 531-A.

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[6] Opinion No. 531, 147 FERC ¶ 61,234 at PP 144-145 & n.285. "*Hope*" and "*Bluefield*" refer to a pair of U.S. Supreme Court cases that require the Commission "to set a rate of return commensurate with other enterprises of comparable risk and sufficient to assure that enough capital is attracted to the utility to enable it to meet the public's needs." *Boroughs of Ellwood City, Grove City, New Wilmington, Wampum, & Zelienople, Pa. v. FERC*, 731 F.2d 959, 967 (D.C. Cir. 1984) (citing *FPC v. Hope Nat. Gas Co.*, 320 U.S. 591, 603 (1944) (*Hope*) and *Bluefield Waterworks Improvement Co. v. Pub. Serv. Comm'n of W.V.*, 262 U.S. 679 (1923) (*Bluefield*)).

[7] As discussed further below, the Risk Premium model estimates cost of equity using the implied premium that provided over Baa-rated utility bonds by regulatory decisions and settlements. The CAPM derives the ROE through the risk premium observed from the risk premium of a DCF analysis of S&P 500 dividend-paying companies. The Expected Earnings model is a method of calculating the earnings that an investor expects to receive on the book value of a particular stock.

[8] Opinion No. 531, 147 FERC ¶ 61,234 at PP 147-149.

[9] *Id.* P 146.

B. Opinion No. 551 *et seq.*

5. On November 12, 2013, multiple complainants[10] filed the First Complaint in Docket No. EL14-12-000 pursuant to section 206 of the FPA, alleging, among other things, that the MISO TOs' base ROE reflected in MISO's Open Access Transmission, Energy and Operating Reserve Markets Tariff was unjust and unreasonable.[11] At the time of the First Complaint, MISO TOs had a base ROE of 12.38% (except for the ATCLLC zone which had a 12.20% ROE),[12] and their total ROE (i.e., the base ROE plus any ROE adders approved by the Commission) was not permitted to exceed 15.96%. The Commission established the MISO TOs' preexisting 12.38% ROE in a 2002 decision.[13] That ROE was based on a DCF analysis using financial data for the

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[10] The complainants consist of a group of large industrial customers: Association of Businesses Advocating Tariff Equity (ABATE); Coalition of MISO Transmission Customers (Coalition of MISO Customers); Illinois Industrial Energy Consumers (IIEC); Indiana Industrial Energy Consumers, Inc. (INDIEC); Minnesota Large Industrial Group (MLIG); and Wisconsin Industrial Energy Group.

[11] The following MISO transmission owners were named in the First Complaint: ALLETE, Inc. for its operating division Minnesota Power (and its subsidiary Superior Water, L&P); Ameren Services Company, as agent for Union Electric Company, Ameren Illinois Company, and Ameren Transmission Company of Illinois; American Transmission Company LLC (ATC); Cleco Power LLC; Duke Energy Corporation for Duke Energy Indiana, Inc.; Entergy Arkansas, Inc.; Entergy Louisiana, LLC; Entergy Gulf States Louisiana, L.L.C.; Entergy Mississippi, Inc.; Entergy New Orleans, Inc.; Entergy Texas, Inc.; Indianapolis Power & Light Company; International Transmission Company; ITC Midwest LLC; METC; MidAmerican Energy Company; Montana-Dakota Utilities Co.; Northern Indiana Public Service Company; Northern States Power Company, a Minnesota corporation, and Northern States Power Company, a Wisconsin corporation, subsidiaries of Xcel Energy Inc.; Northwestern Wisconsin Electric Company; Otter Tail Power Company; Southern Indiana Gas & Electric Company; and Wolverine Power Supply Cooperative, Inc. Intervenor Xcel Energy Services Inc. did not join certain of the MISO TOs' pleadings in this proceeding, but generally supported the brief on behalf of respondents Northern States Power Company, a Minnesota corporation, and Northern States Power Company, a Wisconsin corporation.

[12] For the sake of clarity, we refer to this ROE of the MISO TOs as 12.38% in this order, without separately identifying that the ATCLLC zone had a 12.20% ROE. Our discussion and decisions with respect to the MISO TOs' 12.38% ROE also apply to the 12.20% ATCLLC ROE.

[13] *See Midwest Indep. Transmission Sys. Operator, Inc.*, 99 FERC ¶ 63,011, *initial decision affirmed as to base ROE*, 100 FERC ¶ 61,292 (2002), *reh'g denied*, 102 FERC

six-month period ending February 2002.[14] On October 16, 2014, the same date that the Commission issued Opinion No. 531-A, it set the First Complaint for hearing before an Administrative Law Judge and established a refund effective date of November 12, 2013.[15]

6. Following the hearing, the Presiding Judge issued an Initial Decision,[16] and the Commission subsequently issued Opinion No. 551.[17] In Opinion No. 551, the Commission calculated the just and reasonable ROE using the two-step DCF methodology from Opinion No. 531 and financial data for the period January 1 through June 30, 2015. The Commission affirmed the conclusions of Initial Decision (I), finding that the Presiding Judge correctly applied the two-step DCF analysis required by Opinion No. 531.[18] The Commission also affirmed the Presiding Judge's determination that, as in Opinion No. 531, there were anomalous capital market conditions such that the Commission had less confidence that the midpoint of the zone of reasonableness produced by a mechanical application of the DCF methodology satisfied the capital attraction standards of *Hope* and *Bluefield*.[19] The Commission found that the Presiding Judge reasonably considered evidence of alternative methodologies for determining the

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¶ 61,143 (2003), *order on remand*, 106 FERC ¶ 61,302 (2004). The ATCLLC zone base ROE of 12.20% was established as part of a settlement agreement that was filed with the Commission on March 26, 2004. In Docket No. ER04-108-000, the Commission approved the uncontested settlement. *Am. Transmission Co. LLC*, 107 FERC ¶ 61,117 (2004).

[14] *Midwest Indep. Transmission Sys. Operator, Inc.*, 99 FERC ¶ 63,011, app. A.

[15] *Ass'n of Bus. Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.*, 149 FERC ¶ 61,049, at P 188 (2014) (MISO I Hearing Order), *order on reh'g*, 156 FERC ¶ 61,060 (2016) (MISO I Rehearing Order). In the MISO I Rehearing Order, the Commission denied requests for rehearing and clarification of the MISO I Hearing Order and clarified that non-public utility transmission owners are subject to the outcome of that proceeding. MISO I Rehearing Order, 156 FERC ¶ 61,060 at PP 47-48.

[16] *Ass'n of Bus. Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.*, 153 FERC ¶ 63,027 (2015) (Initial Decision (I)).

[17] *Ass'n of Businesses Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.*, Opinion No. 551, 156 FERC ¶ 61,234 (2016) (affirming Initial Decision (I), 153 FERC ¶ 63,027).

[18] *See generally* Opinion No. 551, 156 FERC ¶ 61,234 at P 9.

[19] *Id.*

ROE and the ROEs approved by state regulatory commissions, for purposes of deciding to set the ROE at the central tendency of the upper half of the zone of reasonableness, setting the base ROE for MISO TOs at 10.32%.[20] The Commission required MISO TOs to submit a compliance filing to implement their new ROEs effective September 28, 2016, the date of Opinion No. 551, and to provide refunds for the November 12, 2013-February 11, 2015 refund period. Following the issuance of Opinion No. 551, numerous parties submitted requests for rehearing.

C. Second Complaint Against MISO TOs' ROE

7. On February 12, 2015, a new set of complainants[21] filed the Second Complaint in Docket No. EL15-45-000 also alleging that the MISO TOs' base ROE of 12.38% was unjust and unreasonable.[22] Relying on an updated two-step DCF analysis, the Second Complaint complainants argued that the base ROE should be no higher than 8.67%.[23] On

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[20] *Id.*

[21] Complainants for the Second Complaint consist of: Arkansas Electric Cooperative Corporation (Arkansas Electric Cooperative); Mississippi Delta Energy Agency and its two members, Clarksdale Public Utilities Commission of the City of Clarksdale, Mississippi and Public Service Commission of Yazoo City of the City of Yazoo City, Mississippi; and Hoosier Energy Rural Electric Cooperative, Inc. (Hoosier Cooperative).

[22] The following MISO transmission owners were named in the Second Complaint: ALLETE, Inc. (for its operating division Minnesota Power, Inc. and its wholly-owned subsidiary Superior Water Light, & Power Company); Ameren Illinois Company; Union Electric Company (identified as Ameren Missouri); Ameren Transmission Company of Illinois; ATC; Cleco Power LLC; Duke Energy Business Services, LLC; Entergy Arkansas, Inc.; Entergy Gulf States Louisiana, LLC; Entergy Louisiana, LLC; Entergy Mississippi, Inc.; Entergy New Orleans, Inc.; Entergy Texas, Inc.; Indianapolis Power & Light Company; International Transmission Company, ITC Midwest LLC, and Michigan Electric Transmission Company, LLC; MidAmerican Energy Company; Montana-Dakota Utilities Co.; Northern Indiana Public Service Company; Northern States Power Company-Minnesota; Northern States Power Company-Wisconsin; Otter Tail Power Company; and Southern Indiana Gas & Electric Company.

[23] *Ark. Elec. Coop. Corp. v. ALLETE, Inc.*, 151 FERC ¶ 61,219, at P 1 (2015) (MISO II Hearing Order), *order on reh'g*, 156 FERC ¶ 61,061 (2016) (MISO II Rehearing Order).

June 18, 2015, the Commission established hearing procedures and set a refund effective date of February 12, 2015.[24]

8. Parties filed requests for rehearing of the MISO II Hearing Order, and on July 21, 2016, the Commission generally denied these rehearing requests.[25] Following the MISO II Hearing Order, the Presiding Judge issued the Initial Decision on June 30, 2016.[26] The Presiding Judge adopted a zone of reasonableness of 6.75% to 10.68% based on financial data for the period July 1, 2015 through December 31, 2015. The Presiding Judge also determined that the anomalous capital market conditions identified in Opinion No. 531 persisted and, after considering the alternative benchmark methodologies, that the just and reasonable ROE was 9.70%—halfway between the midpoint and the upper bound of the zone of reasonableness. The participants filed briefs on and opposing exception.

D. ***Emera Maine***

9. On April 14, 2017, the United States Court of Appeals for the District of Columbia Circuit (D.C. Circuit) issued its *Emera Maine* decision, vacating and remanding Opinion No. 531 *et seq*. As an initial matter, the D.C. Circuit was not persuaded by New England TOs' argument that an ROE within the DCF-produced zone of reasonableness could not be deemed unjust and unreasonable. The D.C. Circuit explained that the zone of reasonableness established by the DCF is not "coextensive" with the "statutory" zone of reasonableness envisioned by the FPA.[27] Accordingly, the D.C. Circuit concluded that the fact that New England TOs' existing ROE fell within the zone of reasonableness produced by the DCF did not necessarily indicate that it was just and reasonable for the purposes of the FPA.[28]

10. Nevertheless, the D.C. Circuit found that the Commission had not adequately shown that New England TOs' existing ROE was unjust and unreasonable. The D.C. Circuit explained that the FPA's statutory "zone of reasonableness creates a broad range of potentially lawful ROEs rather than a single just and reasonable ROE" and that whether a particular ROE is unjust and unreasonable depends on the "particular

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[24] MISO II Hearing Order, 151 FERC ¶ 61,219 at P 1.

[25] *See* MISO II Rehearing Order, 156 FERC ¶ 61,061.

[26] *Ark. Elec. Coop. Corp. v. ALLETE, Inc.*, 155 FERC ¶ 63,030 (2016) (Initial Decision (II)).

[27] *Emera Maine*, 854 F.3d at 22-23.

[28] *Id.* at 23.

circumstances of the case."[29] Thus, the fact that New England TOs' existing ROE did not equal the just and reasonable ROE that the Commission would have set using the current DCF inputs did not necessarily indicate that New England TOs' existing ROE fell outside the statutory zone of reasonableness.[30] As such, the D.C. Circuit concluded that Opinion No. 531 "failed to include an actual finding as to the lawfulness of [New England TOs'] existing base ROE" and that its conclusion that their existing ROE was unjust and unreasonable was itself arbitrary and capricious.[31]

11. The D.C. Circuit also found that the Commission had not adequately shown that the 10.57% ROE that it set was just and reasonable. Although recognizing that the Commission has the authority "to make 'pragmatic adjustments' to a utility's ROE based on the 'particular circumstances' of a case," the D.C. Circuit nevertheless concluded that the Commission had not explained why setting the ROE at the upper midpoint was just and reasonable.[32] The D.C. Circuit noted, in particular, that the Commission relied on the alternative models and state-regulated ROEs to support a base ROE above the midpoint, but that it did not rely on that evidence to support an ROE at the upper midpoint.[33] Similarly, the D.C. Circuit noted that the Commission had concluded that a base ROE of 9.39%—the midpoint of the zone of reasonableness—might not be sufficient to satisfy *Hope* and *Bluefield* or to allow the utility to attract capital, but that the Commission had not similarly explained how a 10.57% base ROE was sufficient to meet either of those conditions. Because the D.C. Circuit found that the Commission had not pointed to record evidence supporting the specific point at which it set New England TOs' ROE, the

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[29] *Id.* at 23, 26.

[30] *Id.* at 27 ("To satisfy its dual burden under section 206, FERC was required to do more than show that its single ROE analysis generated a new just and reasonable ROE and conclusively declare that, consequently, the existing ROE was per se unjust and unreasonable.").

[31] *Id.*

[32] *Id.* (quoting *FPC v. Nat. Gas Pipeline Co. of America*, 315 U.S. 575, 586 (1942)).

[33] *Id.* at 29 ("FERC's reasoning is unclear. On the one hand, it argued that the alternative analyses supported its decision to place the base ROE above the midpoint, but on the other hand, it stressed that none of these analyses were used to select the 10.57% base ROE.").

D.C. Circuit held that the Commission had not articulated the "rational connection" between the evidence and the rate that the FPA demands.[34]

12. Based on the D.C. Circuit's conclusion that the Commission had not met its burden either under the first or the second prong of section 206 of the FPA, it vacated and remanded Opinion No. 531 *et seq.*,[35] meaning that Opinion No. 531 is no longer precedential,[36] even though the Commission remained free to re-adopt those determinations on remand as long as it provided a reasoned basis for doing so.[37] The Commission relied extensively on its determinations in Opinion No. 531 in its order on the First Complaint (i.e., Opinion No. 551).

E. **Briefing Orders**

13. On October 16, 2018, the Commission issued an order proposing a methodology for addressing the issues that were remanded to the Commission in *Emera Maine* and established a paper hearing on whether and how this methodology should apply to the four complaint proceedings concerning New England TOs' ROE.[38] In the *Coakley* Briefing Order, the Commission proposed to change its approach to determining base ROE by giving equal weight to four financial models, instead of primarily relying on the DCF methodology. The Commission stated that evidence indicates that investors do not rely on any one model to the exclusion of others. Therefore, relying on multiple financial models made it more likely that the Commission's ROE determination would accurately reflect how investors make their investment decisions.

14. Specifically, the Commission proposed to rely on three financial models that produce zones of reasonableness—the DCF model, CAPM, and Expected Earnings model—to establish a composite zone of reasonableness. The zone of reasonableness produced by each model would be given equal weight and averaged to determine the composite zone of reasonableness.[39]

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[34] *Id.* at 28-30.

[35] *Id.* at 30.

[36] *Id.*

[37] *Id.*

[38] *Coakley v. Bangor Hydro-Elec. Co.*, 165 FERC ¶ 61,030 (2018) (*Coakley* Briefing Order).

[39] *See id.* PP 16, 30.

15. The Commission also proposed a framework for using the composite zone of reasonableness in evaluating whether an existing base ROE remains just and reasonable. The Commission proposed that, in order to find a utility's existing ROE unjust and unreasonable under the first prong of section 206 of the FPA, its ROE must be outside a range of presumptively just and reasonable ROEs for a utility of its risk profile, absent additional evidence to the contrary. In other words, the Commission would dismiss an ROE complaint if the targeted utility's existing ROE falls within the range of presumptively just and reasonable ROEs for a utility of its risk profile unless that presumption is sufficiently rebutted. The Commission explained that, by the same token, a finding that the existing ROE of a utility falls outside that range would support a holding that the ROE has become unjust and unreasonable, absent additional evidence to the contrary.[40]

16. The Commission explained that it would be appropriate to calculate the applicable ranges of presumptively just and reasonable ROEs based on a utility's risk profile because a utility's risk profile remains the "particular circumstance[]" most relevant to determining whether a point within a zone of reasonableness is a just and reasonable ROE for that utility.[41] The Commission further concluded that the "principal consideration for determining whether an existing ROE within the overall zone of reasonableness has become unjust and unreasonable is the risk profile of the utility or utilities for which the Commission is setting the ROE."[42]

17. The Commission proposed that the applicable range of presumptively just and reasonable ROEs for a utility should correspond to those points that are closer to the ROE that the Commission should set for that utility than to the ROE for a utility of a different risk profile.[43] For example, the Commission explained that it typically would be unjust and unreasonable for an average risk utility to receive an ROE that is closer to the ROE that would be just and reasonable for a utility of above- or below-average risk.[44] In particular, for average risk utilities, the Commission proposed that the presumptively just and reasonable range would be the quartile of the zone of reasonableness centered on the central tendency of the composite zone of reasonableness. For below average risk utilities, the Commission proposed that such range would be the quartile of the zone of reasonableness centered on the central tendency of the lower half of the zone of

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[40] *See id.* PP 16, 28.

[41] *Id.* P 24 (quoting *Emera Maine*, 854 F.3d at 23).

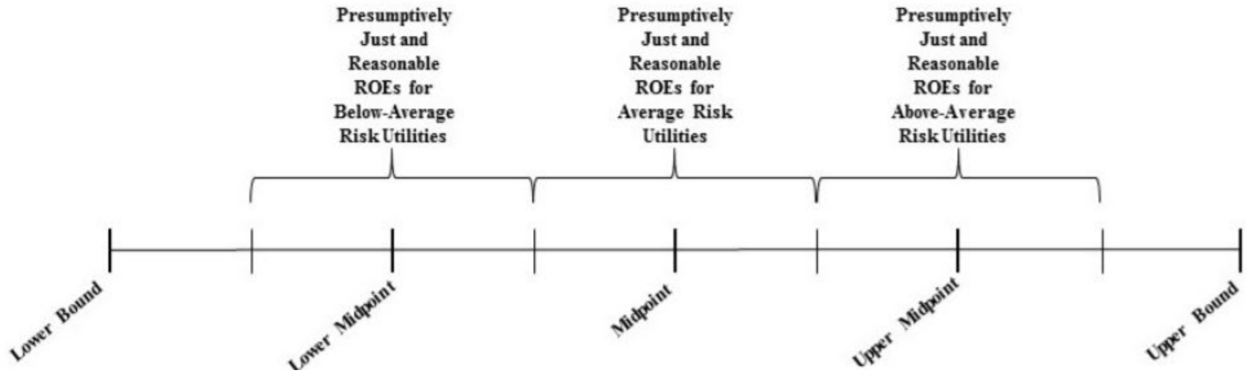
[42] *Id.* P 28.

[43] *Id.* P 27.

[44] *Id.* P 26.

reasonableness. For above average risk utilities, the Commission proposed that such range would be the quartile of the zone of reasonableness centered on the central tendency of the upper half of the zone of reasonableness.[45] The Commission illustrated how these presumptively just and reasonable quartile ranges would be divided as follows:

Figure 1: Zone of Reasonableness Quartiles



18. For purposes of establishing a new just and reasonable base ROE when the existing base ROE has been shown to be unjust and unreasonable, the Commission proposed using the above three models, plus the Risk Premium model. The Risk Premium model produces a single numerical point rather than a range; therefore, the Commission did not propose to use it to establish a composite zone of reasonableness. The Commission proposed to determine a new just and reasonable ROE for average risk utilities by determining the midpoint/medians of each zone of reasonableness produced by the DCF, CAPM, and Expected Earnings models and averaging those ROEs with the Risk Premium ROE, giving equal weight to each of the four figures.[46] The Commission

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[45] *Id.*

[46] *See* Opinion No. 569, 169 FERC ¶ 61,129 at P 344 ("In determining the central tendency of the zone of reasonableness, the Commission has distinguished between cases involving an RTO-wide ROE and cases involving the ROE of a single utility (or pipeline). In cases involving an RTO-wide ROE, the Commission has held that the midpoint is appropriate. The Commission has reasoned that, because an RTO-wide ROE will apply to a diverse set of companies, the range of results becomes as important as the central value, and the midpoint fully considers that range, because it is derived directly from the endpoints of the range . . . By contrast, in cases involving a single utility, the Commission has held that using the median is appropriate, because the median 'is the most accurate measure of central tendency for a single utility of average risk.'") (citing *SoCal Edison*, 131 FERC ¶ 61,020, at P 91 (2010), *remanded on other grounds sub nom. S. Cal. Edison Co. v. FERC*, 717 F.3d 177, 183-87 (D.C. Cir. 2013) (*S. Cal. Edison v. FERC*)); Briefing Order, 165 FERC ¶ 61,118 at n.40: "The Commission will continue to use the midpoint of the zone of reasonableness as the appropriate measure of central

proposed to use the midpoint/medians of the lower and upper halves of the zones of reasonableness to determine ROEs for below average and above average risk utilities, respectively, and average those ROEs with the Risk Premium ROE.[47]

19. On November 15, 2018, the Commission issued the Briefing Order in these proceedings. In that order, the Commission similarly established a paper hearing on whether and how the methodology proposed in the *Coakley* Briefing Order should apply to the two proceedings pending before the Commission involving MISO TOs' ROE.[48]

F. Opinion No. 569

20. On November 21, 2019, the Commission issued Opinion No. 569 in which it applied a revised methodology for analyzing existing base ROEs under section 206 of the FPA. The revised methodology applied in Opinion No. 569 did not use the Expected Earnings or Risk Premium models as was proposed in the Briefing Order, and instead used only the DCF model and CAPM in the Commission's determinations under the first and second prongs of section 206. The methodology applied in Opinion No. 569 gave equal weight to the DCF model and CAPM by averaging the top and bottom of the DCF and CAPM zones of reasonableness to produce a composite zone of reasonableness.[49] In addition, in Opinion No. 569, the Commission reaffirmed its use of a two-step DCF analysis that gives one-third weight to a long-term growth rate based on projected growth in gross domestic product (GDP).[50] The Commission also held that it would continue to rely exclusively on the IBES as the preferred source for the DCF short-term growth projection, absent compelling reasons otherwise.[51] The Commission further held that only the short-term growth rate should be used to calculate the (1+.5g) adjustment to dividend yield in the DCF analysis for the CAPM.[52]

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tendency for a diverse group of average risk utilities and the median as the measure of central tendency for a single utility."

[47] *Id.* P 17.

[48] *See* Briefing Order, 165 FERC ¶ 61,118 at P 1.

[49] *See, e.g.*, Opinion No. 569, 169 FERC ¶ 61,129 at PP 37, 276.

[50] *Id.* PP 151-159.

[51] *Id.* P 133.

[52] *Id.* PP 98-100.

21. In Opinion No. 569, the Commission also adopted a specific CAPM methodology. First, the Commission adopted the use of the 30-year U.S. Treasury average historical bond yield over a six-month period as the risk free rate.[53] Second, the Commission held that the CAPM expected market return should be estimated using a forward-looking approach based on applying the DCF model to the dividend paying members of the S&P 500.[54] In addition, the Commission approved the use of a one-step DCF model using only short-term three to five-year growth projections for the DCF analysis of the dividend paying members of the S&P 500. The Commission also held that IBES should be the sole source of the short-term earnings growth estimates used in the DCF analysis that is part of the CAPM analysis[55] and that S&P 500 companies with growth rates that are negative or in excess of 20% should be screened from the DCF analysis.[56] Finally, the Commission held that the CAPM analysis should include a size premium adjustment.[57]

22. In addition to the above holdings concerning the DCF and CAPM models, the Commission also adopted a revised low-end outlier test that eliminates DCF and CAPM proxy group ROE results that are less than the yields of generic corporate Baa bonds plus 20% of the CAPM risk premium.[58] The Commission also adopted the high-end outlier test that was proposed in the *Coakley* Briefing Order and the Briefing Order in these proceedings, which treats as high-end outliers any proxy company whose cost of equity estimated under the model in question is more than 150% of the median result of all of the potential proxy group members in that model before any high or low-end outlier test is applied, subject to a "natural break" analysis.[59] The Commission also reaffirmed its use of the midpoint, rather than the median, as the measure of central tendency for ROEs that applied to groups of utilities.[60]

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[53] *Id.* P 238.

[54] *Id.* PP 260-273.

[55] *Id.* PP 274-276.

[56] *Id.* PP 267-268.

[57] *Id.* PP 296-303.

[58] *Id.* PP 19, 387-89.

[59] *See id.* PP 367-68, 375.

[60] *Id*. PP 409-413.

G. Requests for Rehearing

23. On December 23, 2019, the following parties to one or both of these proceedings filed requests for rehearing of Opinion No. 569: MISO TOs, the Complaint-Aligned Parties (CAP);[61] the Resale Power Group of Iowa (RPGI); Louisiana Public Service Commission (LPSC); Exelon Corporation (Exelon); Transource Energy, LLC (Transource Energy); and Ameren Services Company, on behalf of its transmission-owning public utility affiliates Ameren Illinois Company d/b/a Ameren Illinois, Union Electric Company d/b/a Ameren Missouri, and Ameren Transmission Company of Illinois (collectively, Ameren). In addition, on December 20, 2019, DTE Electric Company, Consumers Energy Company and Alliant Energy Corporate Services, Inc. (collectively, DTE), parties to both proceedings, filed a request for rehearing. On December 23, 2019, the Indicated PJM Transmission Owners (PJM TO)[62] filed a motion to lodge and request for rehearing.

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[61] For purposes of the their request for rehearing, CAPs include the following entities: American Municipal Power, Inc. (AMP); ABATE, Coalition of MISO Customers, IIEC, INDIEC, MLIG, and Wisconsin Industrial Group (WIEC) (collectively, Joint Complainants); Joint Consumer Advocates, including Indiana Office of Utility Consumer Counselor, Iowa Office of Consumer Advocate, Michigan Citizens Against Rate Excess, Minnesota Department of Commerce, and Citizens Utility Board of Wisconsin; Joint Customers, including Arkansas Electric Cooperative, Cooperative Energy, and Hoosier Cooperative; Organization of MISO States, Inc. (OMS); Mississippi Public Service Commission (MS PSC), Missouri Public Service Commission (MO PSC) and Missouri Joint Municipal Electric Utility Commission (MJMEUC) (collectively, Missouri-Mississippi Parties or MOMs); and Southwest Electric Cooperative, Inc. (SWEC). For purposes of the CAPs briefs in the Second Complaint proceeding, CAPs include Industrial Consumer Groups (ICG), comprising ABATE, Coalition of MISO Customers, IIEC, INDIEC, MLIG, and WIEC; Joint Consumer Advocates, comprising Illinois Citizens Utility Board, Indiana Office of Utility Consumer Counselor, Iowa Office of Consumer Advocate, Michigan Citizens Against Rate Excess, Minnesota Department of Commerce, and Citizens Utility Board of Wisconsin; Joint Complainants and Intervenor (JCI), comprising Arkansas Electric Cooperative, Cooperative Energy, and Hoosier Cooperative; OMS; Missouri-Mississippi Parties; and SWEC.

[62] For purposes of this filing, the PJM TOs are American Electric Power Service Corporation, on behalf of its affiliates, Appalachian Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company, Wheeling Power Company, AEP Appalachian Transmission Company, AEP Indiana Michigan Transmission Company, AEP Kentucky Transmission Company, AEP Ohio Transmission Company, and AEP West Virginia Transmission Company; Duquesne Light Company; Exelon; PPL Electric Utilities Corporation; and Public

24. In addition, multiple non-parties filed requests for rehearing and other motions. On December 23, 2019, the following entities filed such requests and/or motions: PPL Electric Utilities Corporation (PPL Electric) filed a motion to intervene out-of-time and motion to lodge; Southern California Edison Company (SoCal Edison) filed a motion to comment; American Electric Power Service Corporation[63] (AEP) filed a motion to intervene out-of-time and motion to lodge; San Diego Gas & Electric Company (SDG&E) filed a motion to intervene out-of-time and motion for Clarification, or in the alternative, request for rehearing; FirstEnergy Service Company (FirstEnergy) filed a request for rehearing and motion for late intervention; WIRES LLC filed a motion to intervene out-of-time, motion to lodge, and request for rehearing; Public Service Electric and Gas Company (PSEG) filed a motion to intervene out-of-time; Edison Electric Institute (EEI) filed a motion to intervene out-of-time, motion to lodge, and request for rehearing; AEP Indiana Michigan Transmission Company, Inc. filed a motion to intervene out-of-time; and the Southwest Power Pool, Inc. (SPP) Transmission Group[64] filed public comments concerning Opinion No. 569. On December 23, 2019, New England TOs[65] filed a letter requesting that, if the Commission intends to use the

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Service Electric and Gas Company. Some, but not all, of the PJM TOs have timely intervened in these proceedings.

[63] American Electric Power Service Corporation filed on behalf of Appalachian Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company, Wheeling Power Company, AEP Appalachian Transmission Company, AEP Kentucky Transmission Company, AEP Ohio Transmission Company, and AEP West Virginia Transmission Company.

[64] For purposes of this filing, the SPP Transmission Group is Evergy Kansas Central, Inc., Evergy Metro, Inc., Evergy Missouri West, Inc. (subsidiaries of Evergy, Inc. that were formerly known as Westar Energy, Inc., Kansas City Power & Light Company, and KCP&L Greater Missouri Operations Company, respectively), American Electric Power Service Corporation, on behalf of its affiliates, Public Service Company of Oklahoma, Southwestern Electric Power Company, Oklahoma Transmission Company and Southwestern Transmission Company (collectively AEP-West), The Empire District Electric Company (a Liberty Utilities company), Oklahoma Gas & Electric Company, and Southwestern Public Service Company.

[65] For purposes of this letter, the New England TOs are: Emera Maine f/k/a Bangor Hydro-Electric Company, Central Maine Power Company, New England Power Company d/b/a National Grid, New Hampshire Transmission LLC, Eversource Energy Service Company (on behalf of its operating company affiliates: The Connecticut Light and Power Company; NSTAR Electric Company; and Public Service Company of New Hampshire, each of which is doing business as Eversource Energy), The United

outcome of these proceedings to establish any ROE policies or precedent that would apply to the New England TOs, then the Commission consider the arguments that the New England TOs made in their supplemental brief in the complaint proceedings regarding their base ROE in which the *Coakley* Briefing Order was issued. On January 7, 2020, the American Public Power Association (APPA) and Transmission Access Policy Study Group (TAPS) filed a conditional motion to intervene out-of-time and conditional motion to lodge.

H. Subsequent Filings

25. On January 7, 2020, CAPs filed an answer in opposition to the late motions to intervene and alternative motion for leave to respond to non-party comments. On January 10, 2020, EEI and WIRES LLC filed a motion for leave to answer and answer to CAPs' January 7 answer. On January 13, 2020, FirstEnergy filed a motion for leave to answer and answer to CAPs' January 7 answer. On January 21, 2020, PPL Electric filed a motion for leave to answer and answer to CAPs' January 7 answer. On January 28, 2020, CAPs filed a motion to strike portions of various entities' requests for rehearing and motions. On February 12, 2020, MISO TOs filed a motion for leave to answer and answer to certain portions of entities' requests for rehearing, as well as CAPs' January 7 answer and the APPA and TAPS January 7 conditional motion to intervene out-of-time and conditional motion to lodge. On February 12, 2020, the PJM TOs, MISO TOs and Exelon filed separate answers to CAPs' January 28 motion to strike. On February 13, 2020, Transource Energy also filed an answer to CAPs' January 28 motion to strike. On February 27, 2020, CAPs filed an answer to MISO TOs' February 12 answer.

II. Procedural Matters

26. We deny the motions to intervene out-of-time and the requests for rehearing and other motions included with those motions to intervene out-of-time. In ruling on a motion to intervene out-of-time, we apply the criteria set forth in Rule 214(d) of the Commission's Rules of Practice and Procedure.[66] When late intervention is sought after the issuance of a dispositive order, the prejudice to other parties and burden upon the Commission of granting the late intervention may be substantial. Thus, movants bear a higher burden to demonstrate good cause for the granting of such late intervention.[67] In addition, it is generally Commission policy to deny late intervention at the rehearing

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Illuminating Company, Unitil Energy Systems, Inc., Fitchburg Gas and Electric Light Company, and Vermont Transco, LLC.

[66] 18 C.F.R. § 385.214(d) (2019).

[67] *See, e.g., Midwest Indep. Transmission Sys. Operator, Inc.*, 102 FERC ¶ 61,250, at P 7 (2003).

stage, including when the petitioner claims that the decision establishes a broad policy of general application.[68]

27. None of the entities that filed motions to intervene out-of-time have met their burden to justify granting late intervention, and we therefore deny their motions to intervene. We find that granting these late interventions at this stage of the proceedings would substantially disrupt the proceedings,[69] as well as prejudice and place significant additional burdens on the existing parties to these proceedings.[70] The entities seeking late intervention have not demonstrated good cause that would justify granting late intervention despite these negative consequences. This is particularly true in light of the fact that, as discussed below, parties will have an opportunity to argue that the base ROE methodology applied in any of these proceedings should be modified or applied differently because of the specific facts and circumstances of the proceeding involving that party.[71] Accordingly, we deny the motions to intervene out-of-time of PPL Electric, AEP, SDG&E, FirstEnergy, WIRES LLC, PSEG, EEI, AEP Indiana Michigan Transmission Company, Inc., and APPA and TAPS. As these entities are not parties to these proceedings, they may not seek rehearing of Opinion No. 569, and we reject their respective pleadings on that basis.[72]

28. SoCal Edison filed a motion to comment and the SPP Transmission Group filed what it styled as "public comments" regarding Opinion No. 569, without motions to intervene out-of-time. We find that these pleadings are effectively requests for rehearing and, because these entities are not parties to these proceedings, they may not seek rehearing of Opinion No. 569, and we reject their respective pleadings on that basis. We note that only some of the PJM TOs have timely intervened in these proceedings—Duquesne Light Company and Exelon—therefore we will address the requests for rehearing that those two parties made as part of the PJM TOs.

29. The motions to lodge filed by PPL Electric, AEP, WIRES LLC, EEI, and APPA and TAPS are essentially components of requests for rehearing of Opinion No. 569, and

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[68] *See, e.g., Seminole Elec. Coop., Inc.*, 153 FERC ¶ 61,037, at P 11 & n.14 (2015) (citing *PáTu Wind Farm LLC v. Portland General Elec. Co.*, 151 FERC ¶ 61,223, at P 39 & n.85 (2015) (citing *Columbia Gas Transmission Co.*, 113 FERC ¶ 61,066, at 61,243 (2005))).

[69] *See* 18 C.F.R. § 385.214(d)(1)(ii).

[70] 18 C.F.R. § 385.214(d)(1)(iv).

[71] *See infra* at P 204.

[72] 16 U.S.C. § 825*l* (2018); 18 C.F.R. § 385.713(b).

we therefore deny those motions because those entities are not parties to these proceedings. Moreover, even if we were to consider those motions to lodge, and the motion to lodge filed by PJM TOs, as not a component of a request for rehearing, we would deny those motions on the merits. Rule 716 provides that a proceeding may be reopened only when reopening is warranted by a change in condition of fact or law, or by public interest.[73] Additionally, a decision to reopen the record is a discretionary one for the Commission, and Commission policy discourages reopening records, except in extraordinary circumstances in order to prevent administrative chaos and provide finality to proceedings.[74] Further, a demonstration of extraordinary circumstances requires a showing of a material change that goes to the very heart of the case.[75] We find that the entities that filed motions to lodge have failed to show any compelling changes in law, fact, or public interest that would necessitate reopening of the record to lodge the materials that they seek to lodge. As discussed further below in section XV, to the extent that these entities are concerned that Commission actions in these proceedings will affect them and they have filed pleadings or materials in other proceedings that they want the Commission to consider before taking action with respect to their base ROEs, such entities will have an opportunity to present those pleadings or materials and argue that any Commission actions in these proceedings should be modified or applied differently because of the specific facts and circumstances of the proceeding involving that entity.

30. Given that we are denying the motions to intervene out-of-time, we find that CAPs' January 7 answer in opposition to the late motions to intervene or, in the alternative, motion for leave to respond to the pleadings, comments and requests for rehearing submitted by those entities, is moot and we reject it. We therefore also reject the answers to CAPs' January 7 answer submitted by EEI, WIRES LLC, FirstEnergy, PPL Electric, and MISO TOs. We also reject CAPs' January 28 motion to strike portions of various entities' requests for rehearing and motions. To the extent that this motion relates to contents of a motion to lodge that has been denied, as discussed above, we find that it is moot. To the extent that this motion relates to requests for rehearing, it is an answer to a request for rehearing and we reject it because it is prohibited by Rule 713(d)(1) of the Commission's Rules of Practice and Procedure.[76] We find that

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[73] 18 C.F.R. § 385.716(c).

[74] *See, e.g.*, *Gas Producing Enterprises, Inc.*, 28 FERC ¶ 61,008 (1984) (citing *Consolidated Gas Supply Corp.*, 24 FERC ¶ 61,283 (1983), *Transcontinental Gas Pipe Line Corp.*, 23 FERC ¶ 61,152 (1983), and *ICC v. Jersey City*, 322 U.S. 503 (1944)).

[75] *See, e.g.*, *CMS Midland, Inc., Midland Cogeneration Venture Limited Partnership*, 56 FERC ¶ 61,177, at 61,624 (1991).

[76] 18 C.F.R. § 385.713(d)(1).

CAPs have not shown good cause for us to waive this rule to allow their answer.[77] Because we are rejecting CAPs' January 28 motion to strike, we also reject the answers to that motion filed by PJM TOs, MISO TOs, Exelon, and Transource Energy. We reject MISO TOs' February 12 answer to requests for rehearing for the same reasons, and find that this answer is moot as it relates to the APPA and TAPS January 7 conditional motion to intervene out-of-time because, as discussed above, we are denying that motion to intervene out-of-time. Given that we are rejecting MISO TOs' February 12 answer, we also reject CAPs' February 27 answer to that answer.

III. General Model Issues

31. This section pertains to the Commission's decision in Opinion No. 569 to use two models in its base ROE analysis under section 206 of the FPA, rather than either using only the DCF model or using all four models proposed in the Briefing Order. It does not address the specific merits of the individual models, which are discussed in subsequent sections.

A. Opinion No. 569

32. The Commission found that averaging of multiple models reflected how investors made investment decisions and reduced model risk to the greatest extent possible. The Commission cited MISO TOs' witness, Mr. McKenzie, who explained that "when conditions associated with a model are outside of the normal range, there is a risk . . . that the theoretical model will fail to predict or represent the real phenomenon that is being modeled."[78] The Commission also cited Dr. Morin, who found that "Reliance on any single method or preset formula is inappropriate when dealing with investor expectations because of possible measurement difficulties and vagaries in individual companies' market data."[79]

33. The Commission, for reasons specific to the Risk Premium and Expected Earnings Models, determined that they were not appropriate to use for determination of ROEs, for either the first or second prong of section 206 analyses. Opinion No. 569, applying the DCF model and CAPM, reduced the MISO TOs' ROE from the 10.32% prescribed in Opinion No. 551, which was itself a reduction from 12.38%, to 9.88%.

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[77] *See id.* § 385.101(e).

[78] Opinion No. 569, 169 FERC ¶ 61,129 at PP 38-39 (citing Docket No. EL14-12-001, Ex. MTO-22, at 18-19).

[79] *Id*. (citing Roger A. Morin, James, *New Regulatory Finance* (Public Utilities Reports, Inc. 2006) (Morin) at 428).

B. Requests for Rehearing

34. CAPs contend that the Commission erred by finding that the results of the DCF model alone were not just and reasonable. Specifically, CAPs contend that the Commission did not address the testimony of its expert, Dr. Keith Berry, arguing against the Commission's finding of model risk justifying the use of multiple models.[80]

35. Certain parties argue that the Commission acted arbitrarily and capriciously or otherwise did not engage in reasoned decision-making when it determined that the Risk Premium and Expected Earnings models should not be used for ROE determinations. Parties point out that the Commission endorsed using the Risk Premium and Expected Earnings Models in Opinion Nos. 531, 531-A, and 551, as well as the Briefing Order in these proceedings. Specifically, Exelon states that, in the Briefing Order, the Commission found that "it is clear that investors place greater weight on one or more of the other methods for estimating the expected returns from utility investments, as well as taking other factors into account."[81] Exelon contends that the Commission, in Opinion No. 569, insufficiently justified reversing course on this point. Exelon also argues that the Risk Premium and Expected Earnings Models should not be ignored due to their alleged deficiencies, asserting that the CAPM and DCF also have deficiencies. Ameren similarly contends that the Commission's reversal from the Briefing Order was unsupported and contradictory to its findings that investors rely on a diverse set of data sources.[82]

36. Transource Energy argues that the Commission, in Opinion No. 569, was internally inconsistent by giving no weight to the Expected Earnings and Risk Premium Models despite finding that investors rely on multiple models.[83] Transource Energy contends that four models provide a more complete picture than two models, which themselves share many common inputs. Transource Energy asserts that the Commission in Opinion No. 569 issued findings inconsistent with those in Opinion No. 531, which considered three other models, and notes that the Court did not find fault with this finding.[84] Transource Energy states that the CAPM results indicate that a 9.88% ROE was inadequate. Transource Energy also states that the midpoint of the CAPM was 10.45% and contends that no record evidence suggests that 10.45% is overstated.

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[80] CAPs Rehearing Request at 85-87.

[81] Exelon Rehearing Request (citing Briefing Order, 165 FERC ¶ 61,118 at P 37).

[82] Ameren Rehearing Request at 11-13.

[83] Transource Energy Rehearing Request at 15-16.

[84] *Id*. at 17-18

Transource Energy argues that the Commission has previously determined that the DCF is not reliable and that substantial evidence in the record demonstrates that the cost of capital is more consistent with the CAPM result than the DCF result for the complaint time period.[85]

37. Certain parties also argue that the reduction of MISO TOs' ROE in Opinion No. 569 is unjust and unreasonable on the basis that it reduces MISO TOs' ROE to an unreasonably low level. MISO TOs state that, in Opinion No. 551, "the Commission concluded that a 175-basis point ROE reduction . . . could put transmission investment at risk."[86] MISO TOs also argue that the ROE resulting from Opinion No. 569 could cause capital to be diverted to other purposes. Transource Energy similarly contends that the Commission has not supported a 9.88% ROE, and notes that it is below many of the benchmarks provided by state ROEs and other models.[87] Ameren also contends that this methodology threatens utility credit ratings and thus violates *Hope* and *Bluefield*. Specifically, they cite *Bluefield's* finding that the return "should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital."[88]

38. Ameren and Transource Energy state that the Commission should not have excluded the Expected Earnings and Risk Premium models because they have flaws while keeping the DCF and CAPM models, which the Commission acknowledged also have flaws.[89] As an example of DCF and CAPM flaws, Transource Energy notes the Commission's finding in Opinion No. 551 that the DCF model is distorted by a low-interest rate capital market.[90] Ameren and Transource Energy argue, therefore, that the Commission's assertion that there exist imperfections in the Expected Earnings and Risk Premium models is not a valid justification for excluding those models.[91] According to Transource Energy, excluding the Expected Earnings and Risk Premium models results in twice the weighting for the DCF model, and Transource Energy notes

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[85] *Id.* at 14-15.

[86] MISO TOs Rehearing Request at 19 (citing Opinion No. 551, 156 FERC ¶ 61,234 at P 263).

[87] Transource Energy Rehearing Request at 11.

[88] *See, e.g., id*. at 6 (citing *Bluefield*, 262 U.S. at 693).

[89] Ameren Rehearing Request at 12; Transource Energy Rehearing Request at 23.

[90] Transource Energy Rehearing Request at 21-22.

[91] Ameren Rehearing Request at 12; Transource Energy Rehearing Request at 23.

that only including one other model with inputs which share similar characteristics to the DCF does not obviate the issue of whether the DCF is less reliable due to capital market conditions.[92]

39. Ameren and Transource Energy argue that the Commission should keep the four-model framework proposed in the Briefing Order because the Commission has stated that use of multiple models provides more accuracy, consistency with investor expectations, and robustness.[93] Ameren contends that the addition of the Expected Earnings and Risk Premium models would prevent an unreasonable restriction of the zone of reasonableness, and Transource Energy notes that the DCF and CAPM models provide the least diversification benefits of the four the Commission originally proposed.[94] Ameren argues that, when the Commission moved to a two-model ROE methodology, it failed to explain why it excluded certain models (i.e., the Expected Earnings and Risk Premium models) that are relied upon by investors. Ultimately, the new methodology gives zero weight to the excluded models when they were previously assigned a 25% weight in Opinion No. 569. Ameren asserts that the resulting ROE based on only the CAPM and DCF models is not supported by the record and is therefore arbitrary and capricious.[95] Ameren and Transource Energy state that the Commission's use of only the DCF and CAPM models fails to compensate MISO TOs for the actual risks associated with transmission infrastructure development.[96] Ameren and Transource Energy argue that this inadequacy amounts to failure of the capital attraction standards and threatens utility credit metrics, in violation of *Hope* and *Bluefield*.[97]

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[92] Transource Energy Rehearing Request at 21-22.

[93] Ameren Rehearing Request at 12-13; Transource Energy Rehearing Request at 15, 26.

[94] Ameren Rehearing Request at 12-13; Transource Energy Rehearing Request at 16-17, 19.

[95] SoCal Edison Comment, Docket No. EL14-12, at 11-12; Indicated PJM TOs Rehearing Request, Docket No. EL14-12, at 11; Ameren Rehearing Request, Docket No. EL14-12, at 23-25; Wires Comment Rehearing Request, Docket No. EL15-45, et al., at 17; Wires Comment Rehearing Request, Docket No. EL14-12, et al., at 7, 17; FirstEnergy Hearing Request, Docket No. EL15-45, at 3; Transource Energy Rehearing Request, Docket No. EL14-12, at 18-19.

[96] Ameren Rehearing Request at 6; Transource Energy Rehearing Request at 9-12.

[97] Ameren Rehearing Request at 6-7; Transource Energy Rehearing Request at 9-12.

40. MISO TOs also argue that the court's analysis in *Emera Maine* did not require the Commission to construct a new paradigm to satisfy the second prong of section 206. Instead, they argue, the Commission can remedy its error simply by evaluating "the alternative benchmarks and additional record evidence" that warrant selecting a base ROE greater than the midpoint (of whatever range of estimated returns on which the Commission elects to rely) to determine a new, just and reasonable base ROE.[98]

41. MISO TOs contend that, regardless of whether the base ROE prescribed by Opinion No. 569 is a midpoint value of some range of estimated ROEs, section 206 still requires the Commission to explain why, based on the evidence in the record, the new ROE is just and reasonable. MISO TOs contend that the Commission's new approach still fails to do so. MISO TOs contend that the mere fact that the newly prescribed ROE is the midpoint of the composite DCF-CAPM range of estimates does not make that value a just and reasonable ROE. According to MISO TOs, the Commission's selection of the average of the DCF and CAPM midpoints is no better justified in Opinion No. 569 than was the selection of the upper half midpoint found to be arbitrary and capricious in *Emera Maine*.[99]

42. With regard to the First Complaint, MISO TOs argue that *Emera Maine* does not require, and establishes no reason why, the Commission should fundamentally modify the approach of Opinion Nos. 531 and 551, other than to correct or avoid the specific errors the court pinpointed. They argue that the evidence more than amply supports the Commission's conclusion in Opinion No. 551 that the DCF midpoint of 9.29% (stated as 9.3% in Opinion No. 569) is too low to pass muster under *Hope* and *Bluefield*.[100]

C. Commission Determination

43. We disagree with CAPs' contention that the record does not support our finding of model risk as justifying no longer relying solely on the DCF model. Model risk includes the broad conceptual issue of models being imperfect and not always working well in all situations. It also entails errors of specific model inputs, such as the error discussed with respect to the Portland General Electric inputs, discussed in paragraph 145 below. We continue to find that ROE determinations should consider multiple models, both to capture the variety of models used by investors and to mitigate model risk. With respect to the former, we reiterate our findings from Opinion No. 569 in support of the finding

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[98] MISO TOs Rehearing Request at 30-31.

[99] *Id.* at 31-32.

[100] *Id*. at 32.

that use of multiple models reduces model risk. Dr. Morin speaks of the type of potential model errors that comprise "model risk" and why use of additional models is warranted:

> In the absence of any hard evidence as to which method outdoes the other, all relevant evidence should be used and weighted equally, in order to minimize judgmental error, measurement error, and conceptual infirmities. A regulator should rely on the results of a variety of methods applied to a variety of comparable groups, and not on one particular method. There is no guarantee that a single DCF result is necessarily the ideal predictor of the stock price and of the cost of equity reflected in that price, just as there is no guarantee that a single CAPM or Risk Premium result constitutes the perfect explanation of that stock price.[101]

44. We also disagree with contentions that Opinion No. 569 resulted in rates that fail to meet the *Hope* and *Bluefield* standards for just and reasonable rates because they reduce the ROE. As an initial matter, the ROE resulting from this order will be materially higher than the 9.88% resulting from Opinion No. 569 for the First Complaint, rendering such concerns at least partially addressed. Second, cost-of-service principles dictate that the ROE should increase or decrease with the cost of capital. The Commission employs, and at times modifies, financial models, to determine this cost of capital. Although any rate reduction, by reducing earnings, will necessarily adversely affect certain financial metrics, that does not preclude the Commission from reducing rates. It is not incumbent on the Commission to demonstrate that any rate reduction, if supported by evidence demonstrating reduced cost of capital, would not adversely affect utilities' financial metrics. By the logic of certain parties, virtually any rate reduction would be unjust and unreasonable simply because it reduces the ROE and thus harms financial metrics for the affected utilities. In this case, the reduction in ROE from 10.32% in Opinion No. 551 to 9.88% in Opinion No. 569 was less than 4% and Opinion No. 569 extensively supported this such reduction.

45. As described below, we now find that the flaws for the Risk Premium model, when mitigated by certain adjustments, do not render use of the model unreasonable, while the flaws of the Expected Earnings model are significant enough to render the model inappropriate for ROE calculations. We are not persuaded by Ameren's and Transource Energy's arguments that the Expected Earnings model's flaws constitute an insufficient reason to exclude the model because the Commission has acknowledged that other models also have flaws. As the Commission explained in Opinion No. 569, the Commission considered the disadvantages and advantages of each model and concluded that, on balance, the disadvantages of the Expected Earnings model outweigh its

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[101] Morin at 429.

advantages.[102] Simply because other models also have disadvantages does not mean that they have the same level of disadvantages or advantages as those of the Expected Earnings model. The Commission may use its discretion to determine which flaws in various models render the models unreasonable, and thus unusable, and which do not.

46. Regarding arguments that the Commission should include all four models because more models provide additional robustness, we agree—if the models are methodologically and legally sound. As described below, we conclude that the Risk Premium model, with adjustments, is sound, while the Expected Earnings model is not. We are not persuaded by arguments that all four models should be included because they broaden the zone of reasonableness. Such assertions, without support, suggest adopting a zone of reasonableness that is far wider than what the Commission has historically determined would be just and reasonable without sufficient justification as to why such a broader zone of reasonableness is appropriate. Nonetheless, our decision to now construct the ranges of presumptively just and reasonable ROEs by dividing the full zone of reasonableness into equal thirds instead of using the quartiles applied in Opinion No. 569, as discussed in section XIV below, at least in part addresses such concerns by widening the range of presumptively just and reasonable existing ROEs.

IV. DCF

A. Opinion No. 569

1. Short-Term Growth Rate

47. In Opinion No. 569, the Commission found that the DCF and CAPM models should employ IBES short-term growth rates.[103] In the context of the DCF, the Commission explained that IBES was preferable because the IBES growth projections generally represent consensus growth estimates by a number of analysts while *Value Line* growth estimates represent the growth projection of a single analyst.[104] The Commission explained that, while many investors use both IBES and *Value Line* growth rates, only IBES growth rates reflect the analysis of a diverse group of persons in the investment community.[105] The Commission cited academic research that supported the use of IBES

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[102] *See* Opinion No. 569, 169 FERC ¶ 61,129 at P 209.

[103] *Id.* P 251.

[104] *Id.* P 125.

[105] *Id.*

because of its use of multiple analysts' growth projections instead of a single analyst.[106] In addition, the Commission noted that IBES growth projections are generally more timely than the *Value Line* projections because IBES updates its data base on a daily basis as participating analysts revise their forecasts, whereas *Value Line* publishes its projections on a rolling quarterly basis.[107]

2. Long-Term Growth Rate Weighting

48. In Opinion No. 531, the Commission adopted the same two-step DCF model for electric utilities as it has used for natural gas and oil pipelines since the mid-1990s. That model includes a projection of the long-term growth in dividends based on the growth in GDP, in addition to the short-term three to five-year growth projection. The long-term growth projection is given one-third weight, with a short-term growth projection given two-thirds weight.

49. In the Briefing Order, the Commission proposed no changes to its existing two-step DCF model. In Opinion No. 569, the Commission rejected the MISO TOs' contention that, if the Commission applied a high-end outlier test to the ROE results produced by the two-step DCF analysis, the Commission should eliminate the long-term growth projection.[108] Specifically, the Commission rejected MISO TOs' assertion that, if the Commission applies a high-end outlier test to the DCF model, there will remain no rationale for requiring the long-term growth component of the two-step DCF model.[109] The Commission found that the existence of the high-end outlier test is irrelevant to the question of whether a long-term growth projection should be included in a DCF analysis of public utilities.[110] The Commission stated that the high-end outlier test eliminates outlier proxy group members and that it does not address the fact that, over the long-term, companies cannot maintain their short-term growth rates and must, to some extent, converge on the growth rate of the overall economy.[111] Furthermore, the Commission stated that the high-end outlier test that it adopted in Opinion No. 569 does not screen out any of the ROEs produced by the DCF analysis of the proxy groups in these two cases,

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[106] *Id.*

[107] *Id.* P 128.

[108] *Id.* PP 151-159.

[109] *Id.* P 159

[110] *Id.*

[111] *Id.*

including the ROE results discussed above that establish the top of the zones of reasonableness in these two cases.[112]

B. Rehearing Requests

1. Short-Term Growth Rate

50. RPGI states that the Commission correctly used IBES consensus earnings growth estimates rather than *Value Line* earning growth estimates.[113]

51. MISO TOs state that the Commission erred in finding that "IBES is more reliable and robust" than *Value Line* and choosing to use the IBES three to five-year growth projection over *Value Line* growth projections.[114] MISO TOs assert that the Commission erred in finding that there was a general consensus by citing a witness's belief that IBES growth estimates have a higher potential for representing a broader investor community, and the Commission cannot accurately characterize IBES estimates as consensus estimates.[115]

52. MISO TOs assert that the Commission wrongly attempted to relegate *Value Line*'s estimates as "projections by a single institution."[116] MISO TOs argue that the Commission's statement minimizes the fact that *Value Line* estimates are consensus estimates that are the results of a committee composed of peer analysts, and not simply the product of a single analyst.[117] MISO TOs also state that merely averaging analysts' estimates does not create a consensus, and there is no indication that the analysts behind the IBES estimates agree on the published value.[118]

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[112] *Id.*

[113] RPGI Rehearing Request at 61.

[114] MISO TOs Rehearing Request at 63 (citing Opinion No. 569, 169 FERC ¶ 61,129 at P 133).

[115] *Id.* at 64 (citing Opinion No. 569, 169 FERC ¶ 61,129 at P 127 (quoting Commission Trial Staff witness Mr. Robert J. Keyton)).

[116] *Id.* (citing Opinion No. 569, 169 FERC ¶ 61,129 at P 125 n.278).

[117] *Id.* at 64-65.

[118] *Id.* at 65.

53. MISO TOs assert that the Commission's stated preference for IBES over *Value Line* because it is more current is not supported by the record and is arbitrary and capricious.[119] MISO TOs state that the Commission appears to rely on the misperception that IBES' estimates are more up-to-date than *Value Line* simply because IBES can update its daily estimates on a daily basis.[120]

2. Long-Term Growth Rate Weighting

54. MISO TOs request rehearing of the Commission's decision not to adopt any changes to its existing two-step DCF model, averring that, if the Commission adopts a high-end outlier test, it should remove the long-term growth rate portion of the two-step DCF analysis.[121] MISO TOs contend that although no single approach provides a "one-size-fits-all" scenario for estimating the cost of capital, a constant growth DCF better represents investor expectations for the MISO TOs than a two-step DCF model using a long-term growth rate component.[122]

C. Commission Determinate

1. Short-Term Growth Rate

55. We will maintain the longstanding practice of using IBES short-term growth rates for the DCF model, absent compelling reasons for using an alternative source.[123] The record in this and numerous prior proceedings illustrates that the IBES growth rates appropriately inform the DCF analysis.[124] We continue to find that IBES is a reliable source of short-term growth rate data for the DCF model[125] and find that it is appropriate to continue to rely on IBES short-term growth rates in the DCF model given the

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[119] *Id.* at 66.

[120] *Id.* at 66-67.

[121] *Id.* at 77.

[122] *Id.* at 80 (citing McKenzie Supplemental Initial Brief Affidavit, Docket No. EL14-12, at 51–52).

[123] *See, e.g.*, Opinion No. 569, 169 FERC ¶ 61,129 at P 133 ("absent compelling reasons why, we will continue to rely exclusively on IBES as the preferred source for short-term growth projections for the purpose of performing the DCF analysis.").

[124] *See, e.g.*, *id.* at PP 120-133.

[125] *See id.* PP 125-128.

Commission's longstanding practice of relying on those IBES short-term growth rates in the DCF model[126] and the experience that entities coming before the Commission have gained in using IBES in the DCF model in light of that practice. However, we find that, although IBES short-term growth rates should be used for the DCF model,[127] the Commission will consider use of *Value Line* in future proceedings for the CAPM methodology, as discussed below.

2. Long-Term Growth Rate Weighting

56. We disagree with the MISO TOs' request that, if the Commission adopts a high-end outlier test, it should remove the long-term growth rate portion of the two-step DCF analysis and that a constant growth DCF better represents investor expectations for a two-step DCF model using a long-term growth rate component. However, as we note below, we are modifying the high-end outlier test to treat any proxy company as high-end outlier if its cost of equity estimated under the model in question is more than 200% of the median result of all of the potential proxy group members in that model before any high or low-end outlier test is applied, subject to a "natural break" analysis. Although we are not adopting MISO TOs' proposed change, upon reconsideration, we agree that changes to the long-term growth rate are warranted.

57. We grant rehearing to give the short-term growth rate 80% weighting and the long-term growth rate 20% weighting. We note that the court in *CAPP v. FERC*[128] held that the Commission has broad discretion in its weighting choice. Since the Commission established its one-third weighting policy of the GDP in the long-term growth rate, short-term growth rate projections for electric utilities have declined and are now closer to the current GDP growth projection than those from the 1990s when the Commission adopted the two-step DCF using one-third weighting for GDP in the long-term growth

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[126] *See id.* PP 121-123.

[127] In addition, with respect to the First Complaint proceeding, IBES short-term growth rates are the only data available in the record for the study period. *See, e.g.*, MISO TOs Initial Br. (I) at 22 ("MISO Transmission Owners do not propose reliance on growth rates from a source other than IBES to resolve the First Complaint."); MISO TOs Rehearing Request, Docket No. EL14-12-000, at 3 ("The MISO Transmission Owners . . . did not take exception to the Presiding Judge's adoption of the June 2015 Update Period as the appropriate study period for this case. Since they did not object to the June 2015 Update Period, and since there was no *Value Line* growth rate evidence related to that period, the MISO Transmission Owners had no quarrel with, and did not take exception to, the ALJ's ruling that his adoption of the June 2015 Study Period "dictate[d] use of IBES growth rates" insofar as Docket No. EL14-12 was concerned.").

[128] 254 F.3d 289 (D.C. Cir. 2001).

rate for natural gas and oil pipelines[129] that was subsequently adopted for public utilities.[130] For example, in Opinion No. 531, which considered market conditions during the time period from October 2012 to March 2013, the IBES growth projections of the proxy group (before the exclusion of low-end outliers) ranged from -1.90% to 8.10% and averaged 4.58%, only 19 basis points above the 4.39% GDP growth projection in that proceeding.[131] In the First Complaint proceeding, which considered market conditions during the time period from January 2015 to June 2015, the IBES growth projections of the proxy group (before the exclusion of low-end outliers) ranged from -0.64% to 11.66% and averaged 5.03%, 64 basis points above the projected growth in GDP in that proceeding of 4.39%.[132] By contrast, when MISO's 12.38% base ROE was established in 2002, the average IBES short-term growth rate estimate for that year was 7.79%,[133] a full 158 basis points above the estimated 6.21% GDP growth rate from a contemporaneous natural gas pipeline filing.[134]

58. Additionally, average electric utility IBES growth projections are only marginally higher than GDP growth projections. Under these circumstances, investors are likely to view electric utility IBES growth projections as more sustainable than the substantially higher natural gas pipeline IBES growth projections when the Commission established its two-thirds/one-third weighting policy. Therefore, it is reasonable to give the IBES growth projection more weight and give the GDP growth projection less weight. This finding is consistent with Opinion No. 414-A's findings that "long-term projections are

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[129] For example, *New York State Electric & Gas Corp.*, 85 FERC ¶ 63,002 (1998). In Footnote 22, the Initial Order references a GDP growth rate of 5.08%, which was an average of three estimates: 5.10% from Data Resources Inc., 4.95% from Wharton Econometric Forecasting Associates, Inc., and 5.20% from the Energy Information Administration.

[130] *See* Opinion No. 531, 147 FERC ¶ 61,234 at PP 17-23, 32.

[131] *See id.* P 38 and Appendix.

[132] Opinion No. 569, 169 FERC ¶ 61,129 at P 135; Appendix A.

[133] *See Midwest Indep. Transmission Sys. Operator, Inc.,* 100 FERC ¶ 61,292 at app. A.

[134] *See* Trailblazer Pipeline Company, Testimony of Peter J. Williamson, Docket No. RP03-162-000, at P 19.

inherently more difficult to make, and thus are less reliable than short-term projections."[135]

59. We still believe that it is appropriate to consider the long-term growth rate to some extent, but now find that it is appropriate to afford less influence to the long-term growth rate. As the Commission held in Opinion No. 531:

> The DCF model is based on the premise that an investment in common stock is worth the present value of the infinite stream of future dividends discounted at a market rate commensurate with the investment's risk.[[136]] Corporations have indefinite lives and therefore will pay dividends for an indefinite period. For that reason, the Commission stated as long ago as 1983, when it first adopted the constant growth DCF model for gas pipeline cases, that 'projections by investment advisory services of growth for relatively short periods of years into the future' cannot be relied on 'without further consideration.' Thus, as the Commission held in *Ozark*, the constant growth DCF model requires consideration of long-term growth projections.[137]

60. As the Commission found in Opinion No. 531, we continue to recognize the need for a long-term growth projection to "aid in normalizing any distortions that might be reflected in short-term data limited to a narrow segment of the economy."[138]

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[135] *Transcontinental Gas Pipe Line Corp.*, Opinion No. 414-A, 84 FERC ¶ 61,084, at 61,423 (1998).

[136] As the Commission explained, "The DCF model assumes growth for an infinite period of time. This can be approximated as 50 years because the present value of a one dollar dividend received 50 years in the future, discounted at 12%, is less than one cent." *Ozark Gas Transmission Sys*., 68 FERC at 61,105 n.32 (citing Eugene F. Brigham & Louis C. Gapenski, Financial Management 291 (1991)).

[137] Opinion No. 531, 147 FERC ¶ 61,234 at P 33 (quoting *Consol. Gas Supply Corp.*, 24 FERC ¶ 61,046, at 61,105 (1983)) (footnotes omitted).

[138] *Id.* P 38 (quoting Opinion No. 414-A, 84 FERC at 61,423-24).

V. CAPM

A. Opinion No. 569

1. Use of Betas and Size Adjustments

61. In Opinion No. 569, the Commission noted that the Commission found in Opinion No. 531-B that the size adjustment was "a generally accepted approach to CAPM analyses" and continued to find this to be the case.[139] The Commission stated that there was substantial evidence in the record that investors rely on *Value Line* betas. While the Commission acknowledged that there is an imperfect correspondence between the size premia being developed with different betas, it concluded that the size adjustments improve the accuracy of the CAPM results and cause it to better correspond to the costs of capital estimates employed by investors.[140]

62. The Commission also found that the application of size adjustments based on the New York Stock Exchange (NYSE) to dividend-paying members of the S&P 500 is acceptable, as the use of the NYSE for the size premium adjustment enabled Ibbotson Associates to develop a rich data set,[141] and found no evidence that companies in the S&P 500 feature different risk premiums than those in the NYSE.[142]

63. The Commission disagreed with intervenors that the utility industry is unique, and that the size premium adjustment would therefore be inapplicable, as the size premium adjustments are supported by a robust data set. The Commission noted that there are variations in the risk profiles of firms of any industry and there was insufficient evidence in the record to conclude that factors specific to the utility industry insulate smaller utilities from risks such that the CAPM betas sufficiently account for any increased risks and corresponding returns demanded by investors.[143]

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[139] Opinion No. 569, 169 FERC ¶ 61,129 at P 296 (citing Opinion No. 531-B, 150 FERC ¶ 61,165 at P 117).

[140] *Id.* P 297.

[141] Ibbotson Associates, now under Duff & Phelps, has long published a series quantifying this effect for various sizes of firms, pulling from data going back to 1926.

[142] *Id.* P 298.

[143] *Id.* P 303.

2. Exclusion of Growth Rates

64. In Opinion No. 569, the Commission accepted Trial Staff's proposal to screen from the CAPM analysis S&P 500 companies with growth rates that are negative or in excess of 20%. The Commission stated that such a screen is consistent with the elimination of outliers elsewhere in the ROE methodology, as such high or low growth rates are highly unsustainable and non-representative of the growth rates of the electric utilities in the proxy groups.[144]

B. Rehearing Requests

1. Use of Betas and Size Adjustments

65. CAPs state that the size adjustment is inconsistent with other elements of the adopted CAPM model. CAPs explain that the CAPM analysis incorporating a *Value Line* adjusted beta designed to measure market capitalization and a size premium adjustment based on raw betas is not based on substantial evidence.[145] Additionally, CAPs assert that the academic articles cited in Opinion No. 569 do not support the notion that investors rely on size factors.[146]

66. CAPs also argue that Opinion No. 569 appears to have misunderstood CAPs' concerns about the impact of mismatched betas as being whether the *Value Line* adjusted betas are appropriate for use in the CAPM. RPGI states that the issue before the Commission, however, was whether it is appropriate to combine adjusted and raw betas when performing a base CAPM analysis and applying a size premium adjustment.[147]

67. LPSC contends that the size adjustment is flawed because including such an adjustment conflicts with the Commission's determinations that utility growth rates will, in the long run, grow at the rate of the average firm in the economy.[148] LPSC also states that the Commission failed to address its contention that *Value Line* betas are methodologically mismatched to the S&P 500 because *Value Line* betas are calculated

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[144] *Id.* P 267.

[145] CAPs Rehearing Request at 77.

[146] *Id.* at 80.

[147] RPGI Rehearing Request at 77.

[148] LPSC Rehearing Request at 10.

using the NYSE, a different stock index.[149] LPSC asserts that the Commission incorrectly relies on raw betas in its size adjustment portion of the CAPM, while relying on adjusted betas in the rest of its CAPM analysis.[150]

68. RPGI states that the Commission erred by authorizing a size adjustment to the CAPM methodology that is unsupported by substantial record evidence and which arbitrarily inflated the ROE to an unjust and unreasonable level.[151] RPGI asserts that MISO TOs' comments did not recognize that the size premium adjustment is narrowly tailored to address an inability of beta to fully account for the impact of firm size within the CAPM, but failed to recognize that the size adjustment is of firms across the entire economy.[152] RPGI contends that Mr. Parcell's analysis shows that the size adjustment is inappropriate for regulated monopoly electric utilities. They aver that the Commission's silence on the simplification of Mr. Parcell's analysis is a central issue, and that the evidence contradicts the Commission's analysis.[153]

2. Exclusion of Growth Rates

69. MISO TOs argue that the Commission erred in excluding growth rates that are negative or in excess of 20% and argue that this adjustment has no economic justification.[154]

70. Exelon asserts that the Commission discards without justification companies with an IBES growth rate of greater than 20% from the CAPM.[155]

71. CAPs contend that the equity market return estimate, if calculated based on the short-term growth rate, should not exclude S&P 500 companies with negative growth rates. They aver that such exclusions are inappropriate because companies can feature negative growth rates for an extended period. Further, CAPs argue that, for the analysis

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[149] *Id.* at 11.

[150] *Id.* at 14-15.

[151] RPGI Rehearing Request at 31.

[152] *Id.* at 32.

[153] *Id.* at 32-33.

[154] MISO TOs Rehearing Request at 69.

[155] Exelon Rehearing Request at 13.

to be appropriately diverse, these companies should be included, noting that such exclusions include some companies in the electric proxy group.[156]

3. Other Issues

72. Transource Energy asserts that the anomalous capital market conditions that called the DCF midpoint into question also suggest that the CAPM result would be too low, as the CAPM is premised in part on long-term Treasury bond yields.[157]

73. CAPs state that Opinion No. 569's specification of the CAPM methodology is erroneous and produces excessive results.[158] CAPs also note that independent estimates of the CAPM equity market return by financial institutions and other regulators are much lower than the Commission's estimates in Opinion No. 569.[159]

74. LPSC argues that the use of a one-step market DCF analysis in the CAPM fails to account for the long-term growth of stocks in the S&P 500, despite that utility stocks are long-term investments.[160] LPSC argues that the dividend-paying firms in the S&P 500 are not representative of the required return of the market as a whole, and solely relying on those firms results in the required market return being overstated. LPSC further argues that the exclusion of long-term GDP growth rates suggests that these high short-term growth rates will continue in perpetuity, which cannot be true.[161] LPSC further argues that the inclusion of mature, large market cap companies is not a remedy, as even these companies have an average growth rate significantly higher than long-term GDP growth.[162]

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[156] CAPs Rehearing Request at 65-68.

[157] Transource Energy Rehearing Request at 14-15.

[158] CAPs Rehearing Request at 59.

[159] *Id.* at 61-65.

[160] LPSC Rehearing Request at 6.

[161] *Id.* at 7-8 (citing Opinion No. 569, 169 FERC ¶ 61,129 at P 264).

[162] *Id.* at 8 (citing Opinion No. 569, 169 FERC ¶ 61,129 at P 265).

C. Commission Determination

1. Use of Betas and Size Adjustments

75. We continue to find reasonable the use of *Value Line* adjusted betas in the CAPM methodology, as well as the use of raw betas based on the NYSE in the size premium adjustment. We also continue to find that the size adjustment is necessary to correct for the CAPM's inability to fully account for the impact of firm size when determining the cost of equity. As we found in Opinion No. 569, there is substantial evidence indicating that investors rely on *Value Line* betas in making investment decisions.[163] Furthermore, we are not persuaded by LPSC's argument that betas calculated based on the NYSE cannot be used with the S&P 500. We continue to find that size adjustments are appropriate for the utility industry and improve the overall accuracy of the CAPM results.[164]

76. We agree with LPSC that there is imperfect correspondence with applying *Value Line* betas derived from the NYSE to risk premiums developed using the S&P 500. However, we find that it is not reasonable to calculate the risk premium using the full 2800 companies in the NYSE. Furthermore, no parties assert that investors do not use *Value Line* betas or that such betas are materially different from betas derived from only the S&P 500. Thus, while not a perfect match, we find that the use of *Value Line* betas is appropriate for the CAPM calculation.

2. Exclusion of Growth Rates

77. We are not persuaded by MISO TOs' arguments that the CAPM methodology should consider growth rates that are negative or above 20% and continue to find that such a screen is consistent with the elimination of outliers elsewhere in the ROE methodology. Similarly, we disagree with CAPs that negative growth rates should be included. Negative and very high growth rates are both unsustainable and should thus be excluded from the determination of the CAPM risk premium, even if they enhance the diversity of covered companies.[165]

3. Source of Short-Term Growth Rates

78. For the reasons discussed above, we find that IBES is a reliable source of short-term growth rate data and therefore we find it reasonable for IBES growth rates to

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[163] *See* Opinion No. 569, 169 FERC ¶ 61,129 at P 297.

[164] *See id.* PP 297-298, 301, 303.

[165] *See id.* PP 267-268.

be used in the CAPM model. However, we clarify here that we will consider the use of *Value Line* short-term growth rates for the CAPM model in future proceedings. Consistent with our finding that it is beneficial to use different models in the ROE methodology, we find that it may be beneficial to diversify the data sources as well. We believe that diversifying data sources may better reflect the data sources that investors consider in making investment decisions and mitigate the effect of any unusual or incorrect data in a given source. Furthermore, as MISO TOs assert, there is substantial evidence that *Value Line* is used by numerous investors.[166] The Commission has, since Opinion No. 531, recognized the merit of *Value Line* data, as illustrated by its support for *Value Line* betas, discussed above.

79. We are purposefully taking different approaches for the sources of short-term growth rate data in the DCF and CAPM. We believe that, in keeping with the Commission's historic use of IBES for the DCF, the DCF should continue to use IBES short-term growth rate data, as discussed above. By contrast, we believe that the CAPM is a better candidate for a new growth rate data source given that the Commission is newly adopting the CAPM as a direct input into its determination of the zone of reasonableness under the first prong of section 206 and its selection of a just and reasonable replacement ROE under the second prong of section 206.

80. While the Commission found in Opinion No. 569 that IBES data is preferable because it represents consensus growth estimates by a number of analysts, upon further consideration, we conclude that, while *Value Line* estimates may come from a single analyst, those estimates are vetted through internal processes, including review by a committee composed of peer analysts, and thus they similarly incorporate the input of multiple analysts.

81. The Commission also found in Opinion No. 569 that IBES data is preferable because IBES projections are updated more often than the *Value Line* projections. However, after further consideration of the record, including broad requests to allow the use *Value Line* projections,[167] we find here that there is also value in including *Value Line* projections because they are updated on a more predictable basis. *Value Line*'s regular updates provide certainty about updates to key model inputs.

82. Therefore, we conclude that IBES and *Value Line* data both have advantages and thus it is appropriate to consider both data sources. As stated above, however, we believe

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[166] *See, e.g.*, MISO TOs Rehearing Request at 63-69.

[167] *See, e.g.*, *id.* at 63-67; MISO TOs Initial Br. (I) at 22-23; MISO TOs Initial Br. (II), App. 2 McKenzie Aff. (II) at 19-20.

it is appropriate to only consider using *Value Line* in the CAPM, which is being newly adopted, while continuing the traditional exclusive use of IBES data in the DCF model.

83. Although we find it appropriate to consider the use of *Value Line* short-term growth rates in the CAPM in future proceedings, we find that the record in these proceedings is insufficient to adopt use of *Value Line* growth rates for the CAPM at this time. Rather, we will evaluate proposals to use *Value Line* short term growth rates in the CAPM based on evidence produced in future proceedings. As we determine here, consistent with Opinion No. 569,[168] the Commission will screen from the CAPM analysis S&P 500 companies with growth rates that are negative or in excess of 20%. The only CAPM analyses in the record here that apply this screen are those provided by Trial Staff, which use only IBES short-term growth rates.[169] Thus, there is no CAPM analysis in the record that applies the growth rate screen to *Value Line* short-term growth rates. Moreover, we note that, even if we could determine a way in which to apply this screen to the data available in the record, no party has provided a CAPM analysis using only *Value Line* short-term growth rates or another analysis that would allow us to reliably derive a CAPM analysis using only *Value Line* short-term growth rates. The CAPM analyses provided by MISO TOs in these proceedings, which average IBES and *Value Line* short-term growth rates, do not contain sufficient information to allow us to reliably produce a CAPM analysis using only *Value Line* short-term growth rates because those analyses do not specify the weighted average earnings growth rates from *Value Line* that were used in arriving at the short-term growth rates which average IBES and *Value Line*.[170] Accordingly, although we believe, as discussed above, that it may be appropriate to use *Value Line* short-term growth rates in the CAPM, we find that we do not have sufficient record evidence to support adopting such use in these proceedings. Therefore, we will continue to use the CAPM analyses provided by Trial Staff here, but we will consider *Value Line* data in future proceedings.[171]

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[168] *See* Opinion No. 569, 169 FERC ¶ 61,129 at PP 19, 267-268.

[169] *See id.* PP 513 n.1002, 555 n.1048.

[170] *See also* CAPs Rehearing Request, Docket No. EL14-12-002 at 55-56 n.193 (“The record on this issue . . . does not break out the Ex. MTO-30 growth inputs either by source or by S&P 500 company.”).

[171] These analyses are reflected in page 6 of Attachment A to Trial Staff’s Initial Briefs. *See also* Trial Staff Initial Br. (I), Attachment A to App. 2 at 6; Trial Staff Initial Br. (II), Attachment A to App. 2 at 6.

4. Other Issues

84. We disagree with Transource Energy's and CAPs' assertions that the Commission's CAPM methodology produces inadequate and excessive results, respectively, and continue to find the Commission's CAPM methodology to be consistent with conventional CAPM methodologies. Regarding assertions that the CAPM results here exceed those used in other contexts, the Commission is not obligated to use the same exact ROE calculations as other regulatory bodies or investment services, and our CAPM calculations are specific to the electric utility industry. Regarding assertions that the results are unreasonably low, as discussed above, the mere decline of the ROE does not demonstrate that results are unreasonable, and, as discussed below, state-jurisdictional retail ROEs do not serve as an explicit floor on Commission-jurisdictional transmission ROEs.

85. We also continue to find that the CAPM should use a one-step DCF for its risk premium. This is because the rationale for using a two-step DCF methodology for a specific group of utilities does not apply when conducting a DCF study of the dividend-paying companies in the S&P 500, as the Commission found in Opinion Nos. 531-B and 569.[172] A long-term component is unnecessary because of the regular updates to the S&P 500, which allows it to continue to grow at a short-term growth rate and because S&P 500 companies include stocks that are both new and mature, the latter of which have a moderating effect on the short-term growth rates.[173]

86. We also find unsupported Transource Energy's assertion that the anomalous capital market conditions the Commission found rendered the DCF results too low also render the CAPM too low. We are no longer relying on such arguments based on the court's remand of Opinion No. 531. Furthermore, Transource Energy offers no evidence that the CAPM results in this proceeding were unreasonably low.

VI. Risk Premium

A. Opinion No. 569

87. In Opinion No. 569, the Commission determined that it would not use the Risk Premium model for either the first or second prong of the ROE analysis under section 206 of the FPA. It concluded that the Risk Premium model's deficiencies outweigh the additional robustness that it provides. Furthermore, the Commission found that the Risk Premium model requires methodological decisions that would likely

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[172] *See* Opinion No. 531-B, 150 FERC ¶ 61,165 at P 113; Opinion No. 569, 169 FERC ¶ 61,129 at P 263.

[173] *See* Opinion No. 569, 169 FERC ¶ 61,129 at PP 264-266.

undermine transparency and predictability in Commission outcomes.[174] The Commission also explained that the Risk Premium model is largely redundant with the CAPM in that both models use indirect measures to ascertain the risk premium.[175]

88. The Commission agreed with CAPs that the Risk Premium model is likely to provide a less accurate current cost of equity estimate than the DCF model or CAPM because it relies on previous ROE determinations. It found that those determinations' ROE results may not necessarily be directly determined by a market-based method, whereas the DCF and CAPM methods apply a market-based method to primary data. The Commission noted that many previous ROE determinations used in the Risk Premium model were from rate case settlements and that such settlements often involve compromises on a variety of non-ROE issues.[176]

89. The Commission also determined that circularity is particularly direct and acute with the Risk Premium model because it relies on past Commission ROE decisions. The Commission found that MISO TOs' regression analysis accentuates such circularity by largely offsetting the effects of changes in interest rates.[177]

90. The Commission also expressed doubt concerning the application of the regression analyses used by MISO TOs in their Risk Premium model. The Commission contrasted the impact of MISO TOs' analysis, which indicated an increase in the risk premium of 75 basis points for every 100 basis point decline in interest rates, with Dr. Morin's analysis, which indicated an adjustment of 48 basis points. The Commission found that, unlike for DCF and CAPM calculations, MISO TOs did not update and add to the data set for ROE proceedings through the end of the test period in June of 2015, further reducing the robustness of the data set. The Commission observed that, due to using the average of ROEs from each year, MISO TOs' regression in the First Complaint proceeding only has nine observations in its regression, which is a low number of observations for a linear regression and could impact the reliability of the results. The Commission found that MISO TOs' regression created a dynamic in which the Risk Premium analysis will keep the ROE essentially stable in contravention of general financial logic that lower interest rates make it easier to raise capital based on both the reduced opportunity cost of investing in bonds and greater availability of revenue to

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[174] *Id.* P 340.

[175] *Id*. P 341.

[176] *Id*. P 342.

[177] *Id.* P 343.

invest due to the opportunity for carry trades where borrowing low-cost debt is used to finance equity purchases.[178]

91. Additionally, the Commission found that there was insufficient record evidence to conclude that investors rely on risk premium analyses utilizing historic Commission ROE determinations or settlement approvals to determine the cost of capital and make investment decisions.[179] The Commission was also unpersuaded by MISO TOs' arguments that the nature of the industry and the resulting risk premiums changed following the Energy Policy Act of 2005 sufficiently to ignore prior data.

92. The Commission also reconsidered its finding in Opinion No. 531-B that "[g]iven the varying duration of regulatory proceedings, it is difficult, if not impossible, to ensure precise contemporaneity between long-term Treasury bond yields and the cost of equity allowed by a regulator."[180] The Commission found that, although an analysis with such imprecision may have been sufficient for using the Risk Premium model for corroborative purposes, direct use of the model to determine the risk premium would require actual alignment of the test periods and the dates assigned for purposes of comparing the ROE to the risk free rate of return. The Commission stated that, if it were to adopt a precise timing in this proceeding, as a practical matter, such a decision would likely require the Commission to exclude certain proceedings whose test periods predate 2006 and include others, as well as potentially change the dates assigned to yet other proceedings.[181]

93. The Commission also noted that the Risk Premium model entails numerous judgment calls which could be disputed by parties, such as: determining the risk premium resulting from proceedings resolved by settlements with different ROEs for different parties or time periods; whether the ROEs should be assigned to different times for purposes of the Risk Premium analysis; and whether ROEs from settlements resolving multiple proceedings with the same ROE should be counted once or twice. The Commission also noted other methodological decisions, including whether to look at the annual average of ROEs and corresponding risk-free rates of return or look at them individually. Because of this, the Commission found that the Risk Premium model

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[178] *Id*. P 344.

[179] *Id*. P 345.

[180] *Id*. P 348 (citing Opinion No. 531-B, 150 FERC ¶ 61,165 at P 98).

[181] *Id.*

features far more ambiguity and potential for dispute than the DCF and CAPM models, which would lead to higher costs for participation and less predictable results.[182]

94. The Commission stated that the output that the Risk Premium model produces is a single numerical point, and therefore, it does not produce a range which can be used to determine a zone of reasonableness. Accordingly, the Commission explained, the Briefing Order proposed to only use the Risk Premium model in the second prong of the section 206 analysis, but not in the first prong. The Commission stated that it preferred to use the same models in the prong one and prong two analyses to ensure that our ROE determinations under each prong are based on the same data and models and that there was no compelling justification to use different models and data sources to apply this same standard under the two prongs.

B. Rehearing Requests

95. Transource Energy argues that the Commission should utilize the Risk Premium model. Transource Energy argues that none of the Commission's justifications for using the DCF model and CAPM but not the Risk Premium model support reversing its prior findings that the imperfections of the Expected Earnings analysis and Risk Premium models do "not undermine" their usefulness.[183] Transource Energy contends that the Risk Premium model adds useful information that does not rely on the same assumptions as the DCF and CAPM models.[184]

96. Transource Energy also avers that the Commission has not shown that investors do not rely on the Risk Premium (or Expected Earnings) model and that, at most, the Commission shows that investors use those approaches differently than the DCF and

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[182] *Id.* PP 346-350.

[183] Transource Energy Rehearing Request at 23 (citing Opinion No. 531-B, 150 FERC ¶ 61,165 at P 98).

[184] *Id*. (citing Avera Test., Ex. MTO-1, Docket No. EL14-12, at 94 (explaining that unlike DCF models, which indirectly impute the cost of equity, risk premium methods directly estimate investors' required rate of return by adding an equity risk premium to observable bond yields)).

CAPM models.[185] Transource Energy further points to the publication of returns granted by regulators as evidence that investors rely on the Risk Premium model.[186]

97. MISO TOs contend that the implementation questions raised in Opinion No. 569 do not undermine the probity of the Risk Premium analysis supplied by MISO TOs. MISO TOs contend that the Commission's decision in Opinion No. 569 to disregard this evidence is inconsistent with Opinion No. 551, where the Commission evaluated those issues and found that the model was probative.[187]

98. MISO TOs disagree with the Commission's finding that the Risk Premium model is redundant with the CAPM. MISO TOs note that the Risk Premium model focuses on the bond market while the CAPM focuses on the equity market, using different inputs. MISO TOs contend that investors independently rely on both models and note that many jurisdictions employ a Risk Premium approach for determining utilities' cost of equity.[188] MISO TOs argue that the Commission's finding that the stability of the Risk Premium model "defies general financial logic" overlooks that the data inputs used in the Risk Premium model inherently smooth out volatility.[189] They also argue that the Commission's assertion that the DCF and CAPM approaches may have a greater prevalence does not go to the merits of the Risk Premium approach, and it contradicts the record and the Commission's prior finding that Risk Premium is a traditional method investors may use to estimate the expected return from an investment in a company.[190]

99. MISO TOs argue that implementation issues associated with the Risk Premium method are neither insurmountable nor unique to the Risk Premium method. They argue that the Commission's concerns about which ROE inputs to include and "how far back such data should go" are directly analogous to questions regarding proxy group selection and the determination of the study period for the DCF analysis.[191]

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[185] *Id*. at 24.

[186] *Id*. at 25, n.13 (citing MISO TOs, Supplemental Reply Brief, Docket No. EL14-12-003, App. 2 at 44).

[187] MISO TOs Rehearing Request at 52-53.

[188] *Id*. at 47-49.

[189] *Id*. at 48.

[190] *Id.* at 49 (citing Briefing Order, 165 FERC ¶ 61,118 at P 36).

[191] *Id.* at 50.

100. MISO TOs assert that the Commission's concerns regarding circularity arising from using Commission-approved ROEs as inputs are overblown and present in other methodologies. MISO TOs contend that such circularity is limited because of the presumption that orders and settlements are based on market-based methodologies.[192] MISO TOs also aver that the lack of a resulting zone of reasonableness from the Risk Premium model is not a problem because the evaluation of whether an ROE remains just and reasonable is less exact than setting a new base ROE. MISO TOs contend that, while the Commission should include the Risk Premium in setting new ROEs, it does not necessarily need to include it in evaluating existing ROEs.[193]

101. MISO TOs also contend that the Commission's failure to provide guidance on the Risk Premium model's implementation is not a valid justification for omitting the model, particularly since the Commission has reopened the implementation of the models in this proceeding.[194]

102. PJM TOs contend that investors recognize that each of the four financial models in the Briefing Order has its own advantages and disadvantages. PJM TOs contend that investors use multiple models because no single model provides accurate results under all market conditions.[195]

103. PJM TOs argue that the Risk Premium model complements the Commission's DCF model by recognizing that the Risk Premium varies over time and with interest rates whereas the DCF model does not account for this variation.[196] PJM TOs argue that the Commission-authorized ROEs used in the Risk Premium model reflect inputs and analyses of multiple experts as well as the Commission's judgment concerning factors that affect the cost of equity, and contend that investors are likely to consider Commission-authorized ROEs to an extent.[197]

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[192] *Id*. at 50-51.

[193] *Id*. at 51-52.

[194] *Id*. at 49-50.

[195] PJM TOs Rehearing Request at 12.

[196] *Id.* at 26.

[197] *Id*. at 15-16.

C. Commission Determination

104. Upon reconsideration and with the modifications described below, we find that the defects of the Risk Premium model do not outweigh the benefits of model diversity and reduced volatility resulting from the averaging of more models.

105. In Opinion No. 569, the Commission expressed concerns that the Risk Premium model was an iteration of the CAPM, where both compared a derived return to a risk-free rate of return, affording too much weight to similar models. Upon reconsideration, we agree with the PJM TOs that the Risk Premium model is sufficiently distinct from the CAPM to use in our ROE analysis. The Risk Premium relies on corporate utility bonds while the CAPM uses Treasury Bond yields. Additionally, the Risk Premium model relies on the risk premiums implicit in regulatory judgements, including those using the DCF model, while the CAPM relies upon a different set of inputs, including S&P 500 dividend yields and growth rates as well as adjusted betas.

106. The Commission, in Opinion No. 569, found that the Risk Premium model contained substantial circularity. Upon reconsideration, we agree with MISO TOs[198] and find that, while it contains some circularity, the averaging of the results with those of the DCF and CAPM models sufficiently mitigates that circularity. Additionally, all of the models contain some circularity. And, upon consideration of the rehearing requests, we believe that the level of circularity in the Risk Premium model is acceptable.

107. The Commission also found that use of the Risk Premium model was inconsistent with the other models because it could only be used for the second prong of the section 206 analysis because it does not produce a zone of reasonableness. We continue to find that this is a serious concern, particularly in a circumstance where the Risk Premium model's ROE differs substantially from those of the DCF and CAPM models, such that the ROE produced in the second prong could fall within the applicable presumptively just and reasonable range from the first prong despite the challenged ROE falling outside that range or vice versa. To remedy this problem, we will impute the average width of the zones of reasonableness from the CAPM and DCF models onto the ROE produced by the Risk Premium model, with that ROE serving as the measure of central tendency of the zone of reasonableness. Doing so creates a zone of reasonableness for the ROE from the Risk Premium model, which can then be averaged with those of the other models in the first prong of the section 206 analysis. For example, if the Risk Premium model produces an ROE of 10% while the CAPM and DCF produce zones of reasonableness that average 400 basis points wide, the imputed zone of reasonableness for the Risk Premium would be 8% to 12%. We find that this is appropriate because the average width of those zones of reasonableness from models that

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[198] *See* MISO TOs Rehearing Request at 51.

produce a zone of reasonableness is the best estimate of how far a zone of reasonableness should span from a single point like that produced by the Risk Premium model. Moreover, addition of the Risk Premium model to our analysis under the first prong of section 206 will not impact the size of the overall composite zone of reasonableness. Instead, it will merely reflect the Risk Premium model in the zone of reasonableness, based on equally weighted information from the models that directly produce a zone of reasonableness, allowing the Commission to use this model in both prongs. Accordingly, we find that it is appropriate to impute a zone of reasonableness for the Risk Premium model so that our ROE determinations under both prongs of section 206 are based on the same data and models.[199]

108. The Commission also expressed concerns regarding the regression analysis, noting specifically that the low number of observations could impact the reliability of the results.[200] Here we propose to use the individual cases for the Risk Premium analysis and not the average of the data from each year. Consequently, instead of nine observations in the regression analysis as proposed by the MISO TOs, there are 71 observations used in the First Complaint regression and 77 in the Second Complaint regression, leading to a much more robust and reliable result. Although the resulting regression coefficients are similar to those in the MISO TOs' calculations, we conclude that they are now based on more sound inputs and are thus more reliable.

109. The Commission cited use of settlements as a deficiency of the Risk Premium model. Parties may consider many factors when settling rate case proceedings. However, because of how directly ROEs affect rates, we conclude that parties engaged in arms-length negotiations seriously consider the ROE in the course of reaching settlements, even if the records in certain proceedings do not contain specific ROE calculations or testimony. Consequently, upon further consideration, we find that the ROEs from such settlements are reasonable to include in the Risk Premium analysis. However, because of the need to more precisely correspond the timing of ROEs to the corresponding bond yields, discussed below, we revise the bond yields (and corresponding risk premiums) to correspond to the six months preceding the offer of settlement and not Commission orders approving the settlements, as discussed below.

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[199] *See* Opinion No. 569, 169 FERC ¶ 61,129 at P 351 ("We would prefer to use the same models in the prong one and prong two analyses to ensure that our ROE determinations under each prong are based on the same data and models. It would not be logical to use different models and data sources to apply this same standard under the two prongs unless there is some compelling justification for the difference.").

[200] *See* Opinion No. 569, 169 FERC ¶ 61,129 at P 344.

This period, not the six months preceding Commission approval of settlements, best reflects when parties evaluated the ROE.

110. We also find that it is appropriate to eliminate certain cases from the Risk Premium analysis where the Commission did not consider the justness and reasonableness of the base ROE or the zone of reasonableness in making decisions. For example, we are excluding cases where transmission owners joined MISO and received the prevailing 12.38% ROE that was approved in 2002 without examination of the justness and reasonableness of that ROE. Similarly, in an order on a transmission rate incentives filing by PSEG,[201] the Commission explicitly stated that the ROE was beyond the scope of the proceeding.[202] In other cases, the MISO TOs' analysis unjustifiably contained multiple ROEs counted in the analysis from the same case.[203] We are also eliminating cases where the test period is in 2004, well before other proceedings on the list, given that there were likely other proceedings with test periods during 2004 and 2005 that were not included. We also propose, in order for the results of the Risk Premium analysis to be consistent with those of other models, to update the list of applicable cases to include data up through the conclusion of the test periods, which conclude June 2015 and December 2015 for the First Complaint and Second Complaint, respectively.

111. The Commission, in Opinion No. 569, also considered whether the bond yields used to determine the risk premium should more precisely align with test periods of Risk Premium cases. It found that, although a misalignment of the timing of bond yields and test periods might be acceptable when using the Risk Premium model corroboratively, using the model to set the actual ROE demanded correcting this imprecision. We continue to find that the risk premiums should not contain inconsistent dates for the ROEs and for the bond yields. Rather, they should be aligned by corresponding the ROE to the test periods on which it is based. For settlements, the relevant date is the date that parties file the settlement, not when the Commission approves it. Consequently, the six-month time period bond yields should be the six months preceding the settlements. Such information is reflected in the data in Appendix I.

112. In Opinion No. 569, the Commission also found that the record contained insufficient evidence to conclude that investors rely on risk premium analyses utilizing historic Commission ROE determinations or settlement approvals to determine the cost

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[201] *PJM Interconnection, L.L.C. and Pub. Serv. Elec. & Gas Co.*, 147 FERC ¶ 61,142, at P 48 (2014).

[202] However, the analysis does include those cases where the Commission made this finding, but the ROE was modified by settlement.

[203] *See* Appendix I. Note that when a case has multiple *different* ROEs, each of those are counted in the analysis.

of capital and make investment decisions. On rehearing, we find that investors do expect to earn a return on a stock investment that reflects a premium above the return they expect to earn on a bond investment,[204] and that the Risk Premium model is a method of estimating the premium over bond yields that investors require to invest in electric utility equities. In addition, as the Commission noted in Opinion No. 569, investors do observe regulatory ROEs and how changes in authorized ROE levels could affect utility earnings,[205] and while such considerations differ from the type of analysis employed by the Risk Premium model, it is a model that considers regulatory ROEs in estimating the premium that investors require to make equity investments instead of bond investments.

113. The Commission discussed in Opinion No. 569 that the MISO TOs' sample period, beginning in 2006, was substantially shorter than the period used by Dr. Morin, potentially leading to less credible results. We find that, although the data set for determining the risk premium would ideally be longer, that 10 years of data yielding over 60 observations is sufficient, noting that we are extending the sample periods slightly to the end of the updated test periods, as discussed above. Furthermore, the record lacks information on ROE proceedings whose order dates precede 2006.

114. The Commission also noted concerns, raised by Trial Staff, that the Risk Premium model should exclude periods of high volatility, specifically around the beginning of the Great Recession. We conclude that all periods should be included because the Risk Premium analysis should factor in periods where the bond yields change. A full sample size in this case *does* include the outlying periods because they reflect the Risk Premium at the time and such economic disturbances, which periodically recur.

VII. Expected Earnings

A. Opinion No. 569

115. In Opinion No. 569, the Commission determined that, in light of the record as supplemented after issuance of the Briefing Order, it is not appropriate to use the Expected Earnings model in our new base ROE methodology.[206]

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[204] *See, e.g.*, Morin at 108 ("[B]ased on the simple idea that since investors in stocks take greater risk than investors in bonds, the former expect to earn a return on a stock investment that reflects a 'premium' over and above the return they expect to earn on a bond investment.").

[205] Opinion No. 569, 169 FERC ¶ 61,129 at P 345.

[206] *Id.* P 200.

116. In particular, the Commission found that the record does not support departing from our traditional use of market-based approaches to determine base ROE.[207] The Commission determined that under *Hope*—which declares that "the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks"[208]—it is appropriate to consider the value of investment that is actually available to an investor in the market. Outside of the unlikely situation in which the market value and book value are exactly equal, investors do not have the opportunity to invest in an enterprise at its book value. Accordingly, the Commission deemed it most appropriate to exclude the Expected Earnings model, which relies on an enterprise's book value instead of the market value.

117. The Commission explained that the return on book value is not indicative of what return an *investor* requires to invest in the utility's equity or what return an investor receives on the equity investment, because those returns are determined with respect to the current market price that an investor must pay in order to invest in the equity.[209] Specifically, the Commission found that the Expected Earnings model measures returns on book value, without consideration of what market price an investor would have to pay to invest in the relevant company, so it does not accurately measure the investor's expected returns on its investment, and, therefore, has been "thoroughly discredited."[210] In other words, the return on book value does not reflect "the return to the equity owner" that we must ensure is "commensurate with returns on investments in other enterprises," as *Hope* requires; therefore, the Commission found that this model is not useful in ensuring that these standards are satisfied.[211] Furthermore, the Commission found that there was insufficient record evidence to conclude that investors rely on the Expected Earnings analysis to estimate the opportunity cost of investing in a particular utility.[212]

118. The Commission also explained that, while it may be true that the Expected Earnings model does not involve the same complexities as the market-based approaches, this is because it does not reflect a utility's cost of equity.[213] Furthermore, applying the

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[207] *Id.* PP 201, 221.

[208] *Hope*, 320 U.S. at 603.

[209] Opinion No. 569, 169 FERC ¶ 61,129 at P 202.

[210] *Id.* PP 205, 221.

[211] *Id.* PP 202, 221-22.

[212] *Id.* P 210.

[213] *Id.* P 204.

Expected Earnings model in the cost-of-service context would lead to illogical results because a company in such a context would receive a higher overall return when it features a higher equity ratio, despite this indicating a lower risk (and thereby indicating a lower required rate of return by investors) than a company featuring a lower equity ratio.[214] Even though companies with more depreciated assets are generally of lower risk and therefore would merit a lower return, the Expected Earnings model would instead provide higher returns to such companies.[215]

B. Rehearing Requests

119. MISO TOs, Ameren, and Transource Energy seek rehearing of the Commission's decision to exclude the Expected Earnings model in determining base ROEs.[216] Transource Energy argues that the alleged flaws in the Expected Earnings approach actually become strengths when combined with the other models.[217]

120. Transource Energy asserts that the Expected Earnings model is actually market-based in the sense that market participants use it for investment decisions and that the Commission's definition of "market-based" is too narrow.[218] Furthermore, Transource Energy argues that the fact that the Expected Earnings model does not fit into the Commission's narrow definition of "market-based" highlights that it is needed to diversify the other models.[219] On the other hand, MISO TOs contend that the Expected Earnings approach helps ensure a base ROE that meets the requirements of *Hope* precisely because it is *not* market-based.[220]

121. According to MISO TOs, the record demonstrates that the Expected Earnings approach provides a unique perspective that no other model addresses and thus provides

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[214] *Id.* P 223.

[215] *Id.* P 224.

[216] Ameren Rehearing Request at 2, 4-6, 10-13, 23-25; MISO TOs Rehearing Request at 8, 13, 53-62; Transource Energy Rehearing Request at 3-4, 6, 8-10, 15-26.

[217] Transource Energy Rehearing Request at 23.

[218] *Id.* at 16.

[219] *Id.*

[220] MISO TOs Rehearing Request at 59-61.

a check on the market-based cost of equity approaches.[221] MISO TOs assert that, because regulators do not set the returns that investors earn in the capital markets, the Expected Earnings approach provides a direct guide to ensure that the allowed ROE is similar to what other utilities of comparable risk will earn on invested capital.[222] In other words, MISO TOs explain, the Expected Earnings approach measures whether the allowed ROE is sufficient to assure confidence in the financial integrity of an enterprise so as to maintain its credit and attract capital.[223] In addition, MISO TOs state that, because it is not market-based, the Expected Earnings approach avoids the complexities, controversies, and limitations of capital market methods.[224] Transource Energy argues that the fact that Expected Earnings is not used independently of stock price is not disqualifying, because, under the four-model framework originally proposed, this approach actually works in concert with market-based methods like the included CAPM and DCF models.[225] According to MISO TOs, it is precisely because the Expected Earnings method examines the books of a proxy company rather than relying on market data that the approach provides a unique value in assessing whether a Commission-determined ROE meets the *Hope* and *Bluefield* standards.[226]

122. MISO TOs, Transource Energy, and Exelon assert that the Commission's finding that investors do not rely on the Expected Earnings analysis to estimate the ROE that a utility will earn in the future is contrary to the record in this proceeding and the record in the Commission's Notice of Inquiry proceeding[227] regarding its base ROE policy.[228] Transource Energy argues that Opinion No. 569 did not identify changed circumstances regarding how investors use the Expected Earnings and Risk Premium models and does

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[221] *Id.* at 59.

[222] *Id.*

[223] *Id.*

[224] *Id.* at 60 (citing MISO TOs, Supplemental Reply Brief, Docket No. EL14-12-003, App. 2 at 65 (filed Apr. 10, 2019) (McKenzie Supplemental Reply Brief Affidavit)).

[225] Transource Energy Rehearing Request at 24.

[226] MISO TOs Rehearing Request at 62.

[227] *Inquiry Regarding the Commission's Policy for Determining Return on Equity*, 166 FERC ¶ 61,207 (2019) (Base ROE NOI).

[228] MISO TOs Rehearing Request at 54-58; Transource Energy Rehearing Request at 18, 20-21, 24.

not find that investors no longer rely on them in evaluating investment decisions.[229] MISO TOs contend that testimony filed by multiple commenters in the Base ROE NOI proceeding, including MISO TOs, the New England TOs, the PJM TOs, and EEI, clearly demonstrates that investors do rely on the Expected Earnings analysis when making investment choices.[230] Exelon notes that the Commission stated in the Briefing Order that investors use the Expected Earnings model, but then later in Opinion No. 569 stated that there is insufficient evidence that investors rely on the Expected Earnings model. Exelon argues that the Expected Earnings model should be included in the ROE methodology even if only some investors rely on it.[231]

123. MISO TOs and Transource Energy also argue that the Commission cannot ignore evidence concerning the Expected Earnings model that it already found probative.[232] They contend that the Commission found the Expected Earnings approach to be reliable, corroborative evidence of the proper base ROE for electric utilities in Opinion Nos. 531, 531-B, and 551, and cannot now simply ignore evidence pertinent to the question before it with no basis for the sudden change.[233] Ameren contends that the Commission's assertion that the exclusion of the Expected Earnings model in Opinion No. 569 is not inconsistent with its determination in Opinion No. 551 is circular because the question on whether to exclude the model was never asked in Opinion No. 551.[234] Ameren explains that, in Opinion No. 551, the Commission relied on the Expected Earnings model to corroborate its finding and provides no explanation here for completely ignoring it. Ameren contends that this failure to at least consider the Expected Earnings model cannot be reconciled with the Commission's prior finding.[235] According to MISO TOs, the Expected Earnings analysis can inform whether the ROE produced by the Commission's methodology is appropriate, and ignoring pertinent evidence rooted in controlling Supreme Court precedent is arbitrary and capricious and not the product of reasoned

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[229] Transource Energy Rehearing Request at 21.

[230] MISO TOs Rehearing Request at 54-58.

[231] Exelon Rehearing Request, Docket No. EL14-12, at 12-13.

[232] MISO TOs Rehearing Request at 61-62; Transource Energy Rehearing Request at 18, 20-21, 24.

[233] MISO TOs Rehearing Request at 61.

[234] Ameren Rehearing Request at 25.

[235] *Id.*

decision-making.[236] Moreover, Ameren argues that this exclusion constitutes reversible error because the Commission never proposed the two-model approach in the Briefing Order or the Base ROE NOI, no party advocated for this approach in the instant docket, and the record does not support exclusion of the Expected Earnings model.[237]

124. MISO TOs and Transource Energy also assert that the Commission cannot deny the historical and regulatory acceptance of the Expected Earnings approach, as it was used in the Commission's prior "br + sv" approach for determining public utility ROEs and is closely related to the comparable earnings approach that originated in *Hope*.[238] Accordingly, they contend that the Commission can rely on the Expected Earnings model to determine whether a prospective base ROE meets the requirements of *Hope*, and to the extent a base ROE is inconsistent with the Expected Earnings analysis, significant explanation is needed as to how such a base ROE meets the requirements of *Hope*.[239] MISO TOs assert that the Commission should employ the Expected Earnings approach in setting the MISO TOs' base ROE or, failing that, should at least consider it as a check on the base ROE yielded by the Commission's alternative approach.[240]

C. Commission Determination

125. We deny requests for rehearing of the Commission's decision to exclude the Expected Earnings model from its base ROE analysis under section 206 of the FPA. As an initial matter, we note that the requests for rehearing largely repeat arguments parties previously made and which the Commission addressed in Opinion No. 569. Nothing in the rehearing requests persuades us to alter our decision here.

126. We are not persuaded by MISO TOs', Transource Energy's, and Exelon's arguments that investors rely on the Expected Earnings analysis to project utilities' earned ROE. While the record in this proceeding contains evidence that investors have access to data on earnings per book value, we continue to find that it lacks evidence that investors use such data to directly value equities, determine the cost of equity, or make investment decisions without consideration of the market price of the relevant equities.

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[236] MISO TOs Rehearing Request at 62.

[237] Ameren Rehearing Request at 23-24.

[238] MISO TOs Rehearing Request at 60; Transource Energy Rehearing Request at 20-21, 24-25.

[239] MISO TOs Rehearing Request at 60-61; Transource Energy Rehearing Request at 20-21, 24-25.

[240] MISO TOs Rehearing Request at 62.

As the Commission explained in Opinion No. 569,[241] investors cannot use the Expected Earnings model to directly determine the return they would earn from purchasing a company's stock, because the return estimated by that model is a return on the company's book value, not a return on the current stock price, which is what the investor must pay in order to invest in the company. Therefore, the returns estimated by the Expected Earnings model are divorced from the returns required by investors, because investors cannot purchase a company's stock at its book value (except in the very rare instance where a utility's market capitalization happens to exactly equal its book value). Similarly, we are not persuaded by MISO TOs' and Transource Energy's arguments that the Expected Earnings analysis is probative because the Commission, until Opinion No. 531, considered book value in the "br + sv" calculations. Our decision to exclude the Expected Earnings model from our base ROE analysis is not inconsistent with the Commission's prior consideration of book value in this context because such information was used in conjunction with, rather than instead of, the market price of the stocks.

127. Moreover, because the current market values of utility stocks substantially exceed utilities' book value, a utility's expected earnings on its book value will inevitably exceed the return that investors require in order to purchase the utility's higher-value stock, which means that the Expected Earnings model does not accurately measure the returns that investors require to invest in utilities.[242]

128. As explained in Opinion No. 569, the Commission has found that it is important to base the ROE on the returns currently required by investors, and the Expected Earnings model does not measure those returns. Specifically, since the 1980s, the Commission has rejected the use of returns on book value in determining the cost of equity and emphasized the importance of incorporating the market cost of equity when estimating ROEs because the market price is what investors must pay when making an investment and therefore is the basis on which investors measure the return on their investment.[243] As discussed in Opinion No. 569, this is also supported by a variety of academic literature indicating that the Expected Earnings model is not relied upon to directly estimate cost of equity.[244]

129. We are also not persuaded by MISO TOs' arguments that the Expected Earnings model should be used because it provides a unique, non-market-based perspective, and thus increases model diversity. Simply because a model increases model diversity does

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[241] Opinion No. 569, 169 FERC ¶ 61,129 at PP 201-202.

[242] *See id.* P 211.

[243] *See id.* PP 201 & n.426, 202, 216-18.

[244] *Id.* P 218.

not mean that it is necessarily appropriate to include, if the model is fatally flawed. This is the case because the returns on investment received depend on the market price that investors must pay to make their investment, which the accounting-based Expected Earnings model does not consider.

130. In response to MISO TOs' argument that the Expected Earnings model should be used because it avoids the complexities, controversies, and limitations of market-based methods, we stand by the Commission's explanation in Opinion No. 569[245] that the Expected Earnings model is simpler because it does not take into account the vitally important market cost of investing in a utility's equity. The market price that an investor must pay for an investment is a critical factor in determining a utility's cost of equity, and a model that ignores that factor is not useful in estimating cost of equity. The Expected Earnings model's relative simplicity is due to and invalidated by this deficiency.

131. Finally, we disagree with MISO TOs' and Transource Energy's arguments that the Commission cannot exclude the Expected Earnings model now because it already relied on the model as corroborative evidence in the underlying Opinion No. 551 in these proceedings. As the Commission explained in Opinion No. 569,[246] the Commission is now deciding whether to use the Expected Earnings model as a direct input in its ROE estimates—not merely whether to use it as corroborative evidence—and more convincing evidence is required to justify using the model as a direct input. We continue to find that parties have not supplemented the record with this more convincing evidence. We further note that no parties have explained or refuted the Commission's observation in Opinion No. 569 that the use of the Expected Earnings model in this context leads to illogical results of higher ROEs from companies with more equity in their capital structure or more depreciated assets.[247] Furthermore, Opinion No. 531, whose logic and methodology the Commission adopted in Opinion No. 551, was vacated by the court, such that neither form binding precedent.

132. While we do not adopt the Expected Earnings model in our revised methodology here for the reasons discussed above, we do not necessarily foreclose its use in future proceedings if parties can demonstrate that the concerns discussed above have been addressed.

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[245] *Id.* PP 203-204.

[246] *Id.* P 226.

[247] *See id.* P 223.

VIII. Weighting of Models

133. A number of parties made general comments that the Commission erred in overweighting the DCF and CAPM models by excluding the Risk Premium and Expected Earnings models. Section III above addresses such arguments.

A. Opinion No. 569

134. In Opinion No. 569, the Commission chose to use the DCF and CAPM models to determine base ROE, with both approaches being given equal weight. The Commission argued that it was inappropriate to include the Expected Earnings and Risk Premium models, as discussed above. By excluding them, the Commission effectively gave those models a weight of zero in its analysis under prongs one and two of section 206 of the FPA.[248]

135. The Commission also described why it would create the zones of reasonableness for each model based on the proxy company results for those individual models, average the midpoints/medians and zones of reasonableness bounds for the used models, and then determine the midpoints and applicable quartiles based on the averaged zones of reasonableness.[249] The Commission declined to adopt CAPs' proposed alternative of averaging the results for multiple models for each proxy group company before determining the applicable midpoint/median and zone of reasonableness. Further, the Commission noted that there was no record evidence of the models being applied this way in other regulatory proceedings or that the assumptions and structure of the DCF and CAPM models contemplate the isolation of results for specific proxy group companies as the CAPs' proposal would do.

B. Rehearing Requests

136. CAPs state that the Commission should not have equally weighted the results of the DCF and CAPM models in determining the composite zone of reasonableness. According to CAPs, the Commission disregarded the complainants' arguments regarding the "superiority of the DCF model, including evidence of broad industry recognition of the DCF model as the most appropriate way to determine allowable rates of return that meet the standards set out in *Hope* and *Bluefield*."[250] CAPs claim that the Commission relied more heavily on the MISO TOs' assertion that "investors base their decisions on factors more closely aligned with CAPM factors to disregard long-standing precedent

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[248] *Id.* PP 424-427.

[249] *Id*. PP 437-438.

[250] CAPs Rehearing Request at 85.

stating the superiority of the DCF model." CAPs argue that the equal weighting of the DCF and CAPM models is not supported by the record evidence or Commission precedent indicating that the DCF model is superior to the CAPM.

137. CAPs assert that the Commission did not explain its conclusion that equal weighting will reduce model risk associated with a given model more so than giving one model greater weight over the other. CAPs note that the DCF model has not become less reliable over the time that the Commission used it exclusively to determine cost of equity. Lastly, CAPs criticize the Commission for not considering Dr. Berry's rebuttal of the Briefing Order's basis for its new concerns regarding the DCF model's risk. According to CAPs, disregarding parties' arguments constitutes arbitrary and capricious decision making.[251] CAPs also aver that the Commission did not address Dr. Berry's testimony regarding the sequencing of model calculations.

138. Transource Energy argues that the Commission's rationale does not support a 50% weight for the DCF model. Previously with a four-model methodology, the DCF approach received a 25% weight. That approach led to a diverse methodology that minimized measurement errors. According to Transource Energy, assigning no weight to the Expected Earnings and Risk Premium models does not mean that the DCF model should be weighted equally with the CAPM.[252]

139. MISO TOs state that benchmark estimates of utilities' cost of equity using the Risk Premium and Expected Earnings models substantially exceed the Commission's composite midpoint ROE. In addition, MISO TOs state that anomalous capital market conditions undercut the validity of the DCF analysis where that model holds a 50% weight in deriving the composite zone of reasonableness from which the Commission derived the new base ROE it adopted in Opinion No. 569.[253] MISO TOs also note that the Commission previously agreed with Ms. Lapson's conclusion that using the DCF model does not satisfy *Hope* and *Bluefield*. MISO TOs assert that the DCF model does not satisfy *Hope* and *Bluefield* and therefore question the validity of the new ROE methodology when assigning a 50% weight to the DCF model. According to MISO TOs, the "same evidence of prevailing state ROEs on which the Commission relied in Opinion No. 551 undercuts the 50% weighting of the very same DCF analysis in Opinion No. 569."[254] They argue that the Expected Earnings and Risk Premium models can be used to show that the DCF model has a downward bias on the resulting base ROE.

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[251] *Id.* at 85-87.

[252] Transource Energy Rehearing Request, Docket No. EL14-12, at 21-22.

[253] MISO TOs Rehearing Request, Docket No. EL14-12, at 13.

[254] *Id.* at 18-19.

Furthermore, the Commission had previously noted that investors utilize the Expected Earnings and Risk Premium models.[255]

C. **Commission Determination**

140. We disagree with parties that assert that low reliability of the DCF model, the DCF model's similarity to the CAPM in terms of inputs, and the drawbacks of those two models as reasons against equal weighting. We also disagree with other parties that argue that the DCF should receive more weighting than other models given that it has been long-used by regulators. Parties arguing for less weighting do not suggest a specific alternative weighting scheme other than simply reducing the DCF's weight to less than 50% and overlook the distinctions between it and the other models. We disagree with contentions that, because the DCF gives results in these proceedings that are lower than those of the other models, that it should receive *less* weight than they do. The DCF model is clearly used by investors[256] and has been subject to extensive regulatory review and refinement. We also disagree with parties arguing for more weighting of the DCF model, because, as discussed above, we find substantial value in the CAPM and Risk Premium models and the evidence indicates that none of the three models is conclusively superior to any other. As discussed in this order and in Opinion No. 569, each model has unique aspects, and advantages and disadvantages that make it preferable to the other model in some respects, but not other respects.

141. We continue to find that the models used in our methodology should be afforded equal weighting to fully capture the model diversity that each brings. The evidence does not indicate that there is a clearly superior model for estimating cost of equity that should be given more weight than the others and we find that equally weighting the three models will reduce the model risk associated with any particular model more than giving one model greater weight than the other. Consequently, each model shall receive one-third weighting for both the first and second prongs of the section 206 analysis. The revised methodology ultimately addresses the concerns of certain commenters by reducing the weight attributed to the DCF model while expanding the diversity of the ROE methodology by including the Risk Premium model. We disagree with CAPs' assertion that the Commission in Opinion No. 569 failed to address Dr. Berry's concerns regarding model sequencing. The Commission provided a full and reasoned description of why it employed the sequencing order for ROE calculations that it had described in the Briefing Order.

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[255] *Id.* at 22.

[256] *See, e.g.*, Opinion No. 569, 169 FERC ¶ 61,129 at PP 171, 426.

IX. Natural Break Analysis

A. Opinion No. 569

142. In Opinion No. 569, the Commission affirmed the use of a natural break analysis to both the high and low-end outlier screens but declined to set a specific threshold level or formula to use in the analysis. The Commission stated that any numerical outlier test will necessarily be somewhat arbitrary, and that the natural break analysis gives the Commission the flexibility to determine whether a given proxy group company is truly an outlier, or whether it contains useful information.[257]

B. Rehearing Requests

143. MISO TOs argue that, if the Commission retains the high-end outlier test and the natural break analysis, the high-end outlier threshold should be useable as evidence for retaining one or more cost-of-equity estimates that might otherwise be excluded because of a subjectively identified "natural break."[258]

144. MISO TOs contend that the natural break analysis utilized by the Commission has no foundation and invites arbitrary application. MISO TOs contend that the analysis is especially erroneous when applied to the high-end outlier test.[259] MISO TOs also argue that, if the Commission continues to apply a natural break standard to its low-end outlier test, it should not use this threshold to include companies that investors would ignore as unrepresentative of acceptable equity returns.[260]

C. Commission Determination

145. We deny MISO TOs' request for rehearing on the natural break analysis. We note that the high and low-end outlier tests are not meant to be purely statistical tests and refute MISO TOs' assertion that the natural break analysis is inherently flawed because it is subjective. Additionally, we clarify that the natural break analysis may be used as evidence for retaining one or more cost-of-equity estimates that might otherwise be excluded because of a high-end or low-end outlier test. Observations that are shown to be rational and not the result of error may still be included, even if they otherwise would fail one of the outlier tests. By the same logic, the natural break analysis can be used to

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[257] Opinion No. 569, 169 FERC ¶ 61,129 at PP 187-188.

[258] MISO TOs Rehearing Request at 76-77.

[259] *Id.* at 80-82.

[260] *Id.* at 83.

argue for exclusion of cost-of-equity estimates that do not fail either outlier test but can be shown to be irrational, anomalous, or the result of human error.

146. Model inputs can be flawed, due to incorrect inputs or the result of poor judgement by analysts. Such errors can improperly influence the analysis, especially when they affect estimates at the high and low end of the proxy group. As the Commission noted in the Briefing Order, one analyst's error involving the growth projections for Portland General Electric Company reduced the overall Reuters consensus projected short-term percentage growth in earnings from 10.96% to 7.8%.[261] This case illustrates the fallibility of model inputs and the importance of having a natural break analysis to enable the Commission to use its discretion with respect to high or low values.

X. High-End Outlier Test

A. Opinion No. 569

147. In Opinion No. 569, the Commission adopted the high-end outlier test proposed in the Briefing Order, which excludes from the proxy group any company whose cost of equity estimated under the model in question is more than 150% of the median result of all of the potential proxy group members in that model before any high or low-end outlier test is applied, subject to a natural break analysis. The Commission noted that financial metrics for individual utilities can fluctuate dramatically, potentially affecting ROEs that use midpoints as measures of central tendency and found that it was appropriate to eliminate members of the proxy group whose ROEs are unreasonably high.[262]

B. Rehearing Requests

148. MISO TOs argue that the Commission should not adopt any high-end outlier test. MISO TOs argue that the high-end outlier test artificially narrows the zone of reasonableness. MISO TOs further argue that if the Commission retains the high-end outlier test, it should be used only as a rebuttable presumption, and then applied only to the highest of the median values produced by the analyses used.[263]

149. MISO TOs further argue that, even if the Commission retains the high-end outlier test, it should not be applied to the two-step DCF analysis. MISO TOs argue that,

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[261] Briefing Order, 165 FERC ¶ 61,118 at P 19 n.95 (*Coakley* Briefing Order, 165 FERC ¶ 61,030 at P 47).

[262] Opinion No. 569, 169 FERC ¶ 61,129 at P 179.

[263] MISO TOs Rehearing Request at 70-73.

because the median of the two-step DCF may be unreliable or produce unjust and unreasonable results, its use in the high-end outlier test is similarly unreliable.[264]

150. Transource Energy contends that there is no evidence that a logical high-end outlier test exists that would apply generically as the low-end outlier test does. Transource Energy argues that a generic exclusion based on distance from the median may reject potentially useful observations. Transource Energy contends that, if the Commission were to utilize a high-end outlier test, the Commission should treat the test as a high-end cap on the result and not a high-end exclusion of data points.[265]

151. Exelon contends that the high-end proxy group utilities that are excluded under the high-end outlier test represent actual data regarding utilities of a similar risk profile, and thus application of the test changes the range of studied ROEs from those that actual investors consider in the market.[266]

C. <u>Commission Determination</u>

152. We grant in part and deny in part the requests for rehearing on the high-end outlier test. While the high-end outlier test uses the median, it is not solely meant to serve as a statistical test to remove proxy group companies that are not representative of typical utilities. Rather, the high-end outlier test, when coupled with a natural break analysis, screens for observations that are irrationally or anomalously high.

153. As an initial matter, we note that some parties have characterized the high-end outlier test as stricter than it is. As noted above, the high-end outlier test is subject to a natural break analysis, meaning observations that are shown to be rational and not the result of error may still be included, even if they are over the threshold.

154. However, we find that it is appropriate to modify the high-end outlier test to treat any proxy company as high-end outlier if its cost of equity estimated under the model in question is more than 200% of the median—as opposed to the 150% of the median threshold applied in Opinion No. 569—result of all of the potential proxy group members in that model before any high or low-end outlier test is applied, subject to a "natural break" analysis. The high-end outlier test is the Commission's best attempt to use an objective test to identify proxy group ROEs that are irrationally or anomalously high because, for example, they are the result of atypical circumstances that are unrepresentative of the subject utility's risk profile or otherwise likely to be in error.

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[264] *Id.* at 74-76.

[265] Transource Energy Rehearing Request at 28-29.

[266] Exelon Rehearing Request at 13-14.

We recognize such a test with a bright-line threshold could inappropriately exclude ROEs that are rational and not anomalous for the subject utility. In recognition of this risk, we find that increasing the threshold for the high-end outlier test to 200% of the median result of all of the potential proxy group members in the applicable model[267] is appropriate because it will reduce the risk that such rational results are inappropriately excluded. However, as we note above, the continued application of the natural break analysis will still allow the exclusion of ROEs that are truly irrational or anomalously high, even if they fall under the threshold set by this high-end outlier test.

155. While we are modifying the high-end outlier test to increase its exclusion threshold, we find that it is still appropriate to maintain the test as an objective check to help identify observations that are irrationally or anomalously high. This is especially true because we will continue to use the midpoint as a baseline to determine region-wide ROEs for groups of utilities and potentially flawed high-end observations from the proxy group play a large role in an ROE analysis that uses the midpoint. While we note that the addition of the Risk Premium model to the analysis diminishes the impact of outliers, we do not find this to be enough to warrant removal of the high-end outlier test entirely. Thus, the high-end outlier test continues to apply, but with the modification described above.

XI. Low-End Outlier Test

A. Opinion No. 569

156. In Opinion No. 569, the Commission adjusted the low-end outlier test to eliminate from the proxy group ROE results that are less than the yields of generic corporate Baa bonds plus 20% of the CAPM risk premium. The Commission found that it was necessary to exclude ROEs whose yield was "essentially the same expected return" as debt in order to determine the low end of the zone of reasonableness. The Commission noted that the risk premium that investors demand changes over time and found that using 20% of the CAPM risk premium struck an appropriate balance of accounting for the additional risk of equities over bonds while not inappropriately excluding proxy group members whose ROE is distinguishable from debt.[268]

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[267] The high-end outlier test only applies to the DCF model and CAPM because they utilize results of the relevant analysis applied to a proxy group, while the Risk Premium model is derived from actual ROEs.

[268] Opinion No. 569, 169 FERC ¶ 61,129 at PP 184-185.

B. Rehearing Requests

157. RPGI argues that the Commission has not justified revising the low-end outlier test, and specifically has not supported including 20% of the CAPM risk premium.[269]

158. CAPs contend that using the Baa bond yield index is an inappropriate way to determine whether a ROE is an unreliable low-end outlier. CAPs further contend that this is inconsistent with Commission precedent, noting the Commission's explanation in Opinion No. 489 that, when applying a low-end outlier test, "it is appropriate to consider the company's own cost of debt, not the composite debt of the proxy group."[270] CAPs note that applying this to a company's own cost of debt results in OGE Energy being added back into the proxy group for the Second Complaint.[271]

159. CAPs similarly argue that the Commission's use of the risk premium should be rejected. However, CAPs contend that, if the Commission continues to utilize a risk premium, it should instead be 20% of the difference between the CAPM equity market return and the Moody's Baa utility bond yield.[272]

160. MISO TOs argue that the Commission erred in adopting its low-end outlier test and should instead apply the low-end methodology described by Mr. McKenzie in order to account for the inverse relationship between equity risk premiums and bond yields.[273]

C. Commission Determination

161. We deny the requests for rehearing on the low-end outlier test. We are not persuaded by RPGI's and MISO TOs' assertions that the Commission erred in adopting its low-end outlier test based on 20% of the CAPM risk premium. Likewise, we disagree with CAPs that the low-end outlier test is inconsistent with prior Commission precedent. As the Commission noted in Opinion No. 569, the Commission has applied this test differently in the past and did not always examine a company's own cost of debt.[274]

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[269] RPGI Rehearing Request at 27-31.

[270] CAPs Rehearing Request at 88-90.

[271] *Id.* at 94.

[272] *Id.* at 90-92.

[273] MISO TOs Rehearing Request at 83-84.

[274] Opinion No. 569, 169 FERC ¶ 61,129 at P 389 n.783 (citing Opinion No. 531, 147 FERC ¶ 61,234 at P 123).

The Commission also found that "using the specific bond yield for each company . . . renders [the calculations] (and the resulting ROE) less predictable, as the credit ratings for individual companies are likely more volatile than the generic corporate rate Baa credit rating."[275] Thus, we reiterate our finding here that applying the low-end outlier test to the Baa bond yield is appropriate. We also decline to adopt CAPs' proposal to instead use 20% of the difference between the CAPM equity market return and the Moody's Baa utility bond yield, and affirm our use of the United States 30 year treasury note in calculating the CAPM equity risk premium. There is no compelling evidence that, with respect to determining the risk premium, using Moody's Baa utility bond yields is superior to the treasury yields. Treasury yields are generally more stable than corporate bond yields, which here increases model stability. Furthermore, the low-end outlier test already incorporates the Moody's Baa utility bond, to which it adds 20% of the risk premium to determine the test. Using it twice would be unnecessarily duplicative. Additionally, we note that the risk premium is meant to reflect the opportunity cost of investing in equities generally, and therefore, using an industry-specific measure to determine the low end of the risk premium's range is inappropriate.

162. We also decline to adopt MISO TOs' proposed methodology. Opinion No. 569's proposed low-end outlier test methodology recognizes the dynamic nature of risk premiums without eliminating numerous proxy group members as the MISO TOs' methodology might in certain conditions. In Mr. McKenzie's example, use of his proposed test leads to the exclusion of six rather than three companies, the upper three of which feature ROEs very close to those of other companies.[276] This indicates that MISO TOs' proposed outlier test is excluding more than just outliers, systematically adding a significant upward bias to the DCF results.

XII. Consideration of State ROEs

A. Opinion No. 569

163. The Commission found that the ROE determination in these proceedings did not need to consider state-authorized ROEs. The Commission agreed with MISO TOs that there are material differences between state and Commission ROEs. As a result, the Commission stated that it would only consider state-authorized ROEs on a case-by-case

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[275] *Id.*

[276] Appendix 3 to McKenzie Affidavit in MISO TOs Initial Brief.

basis to the extent that the state-authorized ROEs demonstrate that the results of the Commission's CAPM and DCF analyses are substantially excessive or deficient.[277]

B. Requests for Rehearing

164. Ameren, MISO TOs, and Transource Energy all note that the Commission stated in Opinion No. 569 that its new ROE approach would consider state-authorized ROEs, but argue that, despite the express inclusion, the Commission failed to perform this check. These parties assert that the Commission has previously found that transmission ROEs generally should be higher relative to those of distribution-only and integrated electric utilities. These parties claim that the Commission disregarded record evidence of state-authorized ROEs above 9.88%, and argue that this evidence demonstrates that, relative to the risk to transmission, 9.88% is an insufficient level of return to attract capital under the *Hope* and *Bluefield* standards.[278]

165. According to MISO TOs, the Commission's findings that transmission is riskier than state-regulated retail utility operations and that the MISO TOs are at least as risky as integrated utilities require that the MISO TOs' base ROE be somewhat higher than most, if not all, contemporaneous state-authorized ROEs. MISO TOs state that all state ROEs allowed during the Docket No. EL14-12 study period exceeded the DCF midpoint. Indeed, even the midpoint of all state-allowed ROEs, 9.95%, exceeded the base ROE of Opinion No. 569, and 31 out of 58 state-authorized ROEs for integrated utilities were between 10% and 10.4%.[279]

166. MISO TOs argue that *Emera Maine* did not disturb the Commission's finding in Opinion No. 531-B that the proper use of state commission ROEs is to compare the "significant number of state commission-authorized ROEs to the midpoint produced by the application of the Commission's traditional methodology" and determine whether "their levels, relative to each other, were illogical in light of the record evidence concerning the comparative risks of state-level electric distribution and interstate electric transmission." They contend that evidence of prevailing state ROEs during the study period indicates that a base ROE equal to or higher than 10.32% is justified.[280] They state that other estimates of the MISO TOs' cost of equity support the same inference, and thus support the Opinion No. 551 outcome. They note that: the Commission's

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[277] Opinion No. 569, 169 FERC ¶ 61,129 at P 363.

[278] Ameren Rehearing Request at 8-10; MISO TOs Rehearing Request at 14-16; Transource Energy Rehearing Request at 10-14.

[279] MISO TOs Rehearing Request at 33.

[280] *Id.* at 33-34 (citing Opinion No. 531-B, 150 FERC ¶ 61,165 at P 88).

application of the CAPM in Opinion No. 569 resulted in a midpoint of 10.45%; the Commission in Opinion No. 551 accepted a Risk Premium estimate of 10.36% and an Expected Earnings midpoint estimate of 11.99%; and the Briefing Order presented a restated Expected Earnings analysis with a midpoint of 11.41%, and repeated the Risk Premium estimate of 10.36%.[281]

C. **Commission Determination**

167. As an initial matter, the modifications made in this order to the ROE determination methodology result in higher ROEs in these proceedings, at least in part rendering moot concerns about the relative levels of state-authorized ROEs for integrated utility operations versus Commission-authorized transmission ROEs. Furthermore, the 10.02% ROE resulting from this order exceeds the average ROEs in the MISO TOs' analysis for both vertically-integrated utilities and for all utilities.[282] Moreover, MISO TOs' comparison of Commission ROEs in this proceeding with state ROEs over a two-year period, concluding in 2014, before the test period in this proceeding, is inappropriate. As illustrated by the fact that the DCF and CAPM midpoint ROEs in the Second Complaint are lower than those in the First Complaint, capital market conditions can change over time, rendering past comparisons obsolete. The ROEs in this proceeding must reflect capital market conditions during the first half of 2015 for the First Complaint and the second half of 2015 for the Second Complaint, so comparisons to state ROEs during the preceding two years are of limited value. We also continue to find that state-authorized and Commission-authorized ROEs are conceptually distinct and do not necessarily need to be aligned. In Opinion No. 569, the Commission indicated that state-authorized ROEs would only be considered on a case-by-case basis and not as a necessary part of the Commission's ROE methodology, and accordingly we disagree that we were required to consider state-authorized ROEs as part of the ROE determination in this proceeding. Although the Commission may consider a wide range of evidence in its ROE determinations, it is not legally required to base its jurisdictional transmission ROE determinations on the ROEs determined by state utility commissions. Furthermore, that the Commission relied on state ROEs corroboratively in the vacated Opinion No. 531 and in Opinion No. 551 that was pending before the Commission on rehearing, does not create binding precedent that the Commission must justify departure from in its finding that it will not necessarily consider state ROEs when determining transmission ROEs.

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[281] *Id*. at 34.

[282] *See* MTO-20 at 1-2.

XIII. Use of the Midpoint

A. Opinion No. 569

168. The Commission stated that it will continue to use the midpoint to determine the central tendency of the zone of reasonableness in cases involving an RTO-wide ROE, consistent with the policy set forth in the *MISO Remand Order*,[283] and that intervenors did not present a compelling reason as to why that policy should not be applied in this ROE proceeding.[284] The Commission explained that MISO TOs are a diverse set of companies and the central value becomes an important part in determining RTO-wide ROE.[285] The Commission also found that the high and low ends of the DCF and CAPM zones of reasonableness were representative of the highest and lowest risk profiles among the MISO TOs.[286]

B. Requests for Rehearing

169. CAPs contend that the Commission erred in using the midpoint, rather than the median, as the measure of central tendency for the ROE under the second prong of the section 206 analysis. CAPs point out that the Commission has found that the median best represents the central tendency in a skewed distribution[287] and is "less affected by extreme numbers than the midpoint."[288] CAPs find unpersuasive the Commission's finding in Opinion No. 569 that the companies that set the high and the low end of the zone of reasonableness in Opinion No. 569's DCF and CAPM analyses have similar risk

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[283] *Midwest Indep. Transmission Sys. Operator, Inc.*, 106 FERC ¶ 61,302, at PP 9-10 (2004) (*MISO Remand Order*), *aff'd*, *Pub. Serv. Comm'n of Ky. v. FERC*, 397 F.3d 1004 (D.C. Cir. 2005).

[284] Opinion No. 569, 169 FERC ¶ 61,129 at P 409.

[285] *Id.* PP 410-411.

[286] *Id.* PP 412-413.

[287] CAPs Rehearing Request at 83 (citing *S. Cal. Edison Co.*, 131 FERC ¶ 61,020 at PP 114-116, *reh'g denied*, 137 FERC ¶ 61,016 (2011) (SCE Rehearing), *aff'd in relevant part sub nom*. *S. Cal. Edison Co. v. FERC*, 717 F.3d 177 (D.C. Cir. 2013); *Northwest Pipeline Corp.*, 99 FERC ¶ 61,305, at 62,276 (2002). *See also Transcontinental Gas Pipe Line Corp.*, Opinion No. 414-A, 84 FERC at 61,427, *aff'd* Opinion No. 414-B, 85 FERC ¶ 61,323 (1998), *rev. denied sub nom.*, *N.C. Util. Comm'n v. FERC*, 203 F.3d 53 (D.C. Cir. 2000)).

[288] *Id.* (citing SCE Rehearing, 137 FERC ¶ 61,016 at P 19).

profiles to the MISO TOs. CAPs contend that this explanation misses the point because, even if the risk profile of the proxy group companies setting the high and low ends of the DCF and CAPM zones of reasonableness are within that wide variation, the averaged DCF and CAPM midpoints do not correspond to the highest and lowest cost of capital among Respondent MISO TOs. Consequently, according to CAPs, using the highest and lowest ROEs in the DCF and CAPM zones to calculate the presumptively just and reasonable zones or to determine the replacement ROE does not result in emphasizing the full range of the individual MISO TOs' costs of equity to serve a diverse group of TOs.

170. CAPs state that the premise for use of the midpoint is counter-factual because there is no direct correlation between credit ratings and the utilities setting the upper and lower bounds of the composite zone of reasonableness and the highest and lowest credit ratings of the MISO TOs.[289] CAPs state that the Commission dismissed this concern on the basis that such lack of correlation is not a problem because the credit ratings of the proxy companies that turn out to define the DCF-CAPM combined range are within the MISO TOs' wide variation of credit ratings.

C. <u>Commission Determination</u>

171. We disagree with arguments on rehearing that the Commission erred in continuing to use the midpoint as the measure of central tendency when establishing an ROE for groups of utilities like the MISO TOs. Such arguments fail to provide a basis for reversing a court-affirmed finding that it is just and reasonable to use the midpoint as the measure of central tendency for groups of utilities.[290] Additionally, the Commission described in great detail the general correspondence between the credit rating of proxy group companies and those at the high and low end of the zone of reasonableness, even if this examination was not specific to the MISO TOs.[291] The fact that the MISO TOs' highest and lowest credit ratings do not fully correspond to the high and the low ends of the CAPM and DCF zone of reasonableness in this particular proceeding does not change the fundamental purpose of applying the midpoint to groups of utilities, which is capturing a variety of risks that they feature.

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[289] *Id.*

[290] *See Pub. Serv. Comm'n of Ky. v. FERC*, 397 F.3d at 1004, 1010.

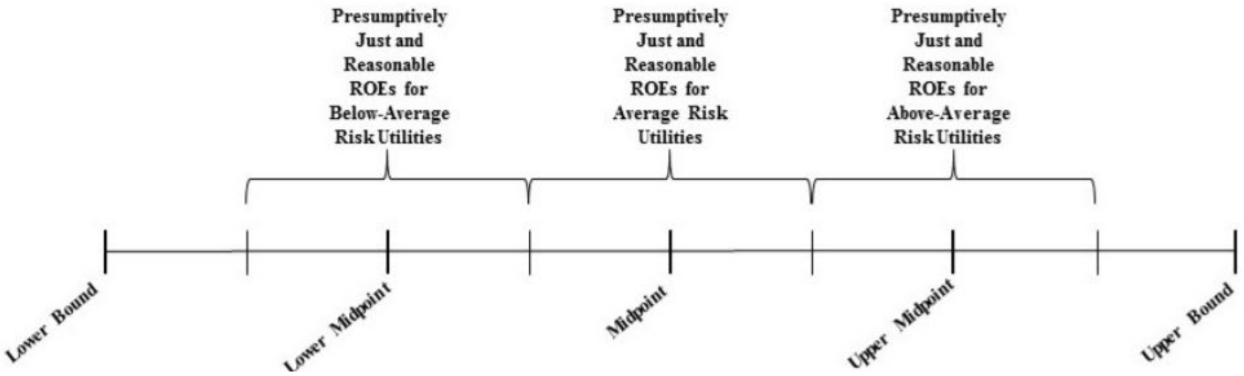
[291] *See* Opinion No. 569, 169 FERC ¶ 61,129 at P 412.

XIV. Ranges of Presumptively Just and Reasonable ROEs

A. Opinion No. 569

172. In Opinion No. 569, the Commission adopted the use of ranges of presumptively just and reasonable ROEs based on the risk profile of a utility or group of utilities to inform the Commission's decision of whether an existing ROE has become unjust and unreasonable, as proposed in the Briefing Order.[292] Specifically, the Commission found that, for average risk utilities, the presumptively just and reasonable range is the quartile of the overall composite zone of reasonableness centered on the central tendency of the overall zone of reasonableness; for below average risk utilities, that range is the quartile of the zone of reasonableness centered on the central tendency of the lower half of the zone of reasonableness; and for above average risk utilities, that range is the quartile of the zone of reasonableness centered on the central tendency of the upper half of the zone of reasonableness. These ranges of presumptively just and reasonable base ROEs located within the overall composite zone of reasonableness are illustrated below.

Figure 1: Zone of Reasonableness Quartiles



173. In constructing the ranges of presumptively just and reasonable base ROEs, the Commission noted its precedent that the midpoint of the overall zone of reasonableness is a good starting place for the placement of an ROE and found that the measure of central tendency for the entire zone of reasonableness should be the starting point for identifying the range of presumptively just and reasonable base ROEs for utilities with an average risk profile.[293] The Commission then found that, similarly, the starting points for identifying the ranges of presumptively just and reasonable base ROEs for utilities with above or below average risk profiles should be the historic measures of central tendency

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[292] *See id.* P 57.

[293] *Id.* P 63 (citing *Emera Maine*, 854 F.3d at 27 (citing *Tenn. Gas Pipeline Co. v. FERC*, 926 F.2d 1206, 1213 (D.C. Cir. 1991)) ("We have noted that the midpoint is a good 'starting place' for the placement of the ROE.")).

of the upper and lower halves of the zone of reasonableness, respectively – their respective midpoints.[294] The Commission explained that it was logical for the end points of those ranges to not be closer to the starting points for the ranges of utilities with different risk profiles than they are to their own starting point. Applying this rationale, the Commission found that the range within the overall zone of reasonableness that best represents presumptively just and reasonable ROEs for average risk utilities is the quartile of the zone of reasonableness centered on the central tendency of the entire zone of reasonableness, while the ranges within the overall zone of reasonableness that best represent presumptively just and reasonable ROEs for above- and below- average utilities are the quartiles centered on the central tendencies of the upper and lower halves of the zone of reasonableness, respectively.[295]

174. The Commission explained that adopting the use of ranges of presumptively just and reasonable base ROEs was necessary to satisfy the requirements of the *Emera Maine* decision, which found that the Commission's decision that "a single ROE analysis generating a new just and reasonable ROE necessarily proved that the Transmission Owners' existing ROE was unjust and unreasonable" is contrary to the FPA.[296] Such ranges were also necessary, the Commission reasoned, because, according to the *Emera Maine* decision, "the zone of reasonableness creates a broad range of potentially lawful ROEs rather than a single just and reasonable ROE," and thus that a finding that a particular ROE is just and reasonable, "standing alone, 'does not amount to a finding that every other rate of return'" is not just and reasonable.[297] The Commission found that, in light of these findings, the Commission's explanation of the particular circumstances that support an explicit finding that the existing ROE has become unjust and unreasonable must include a showing that the existing ROE is now outside some range of potentially just and reasonable ROEs within the zone of reasonableness for the public utility at issue, in light of our estimate of the current market cost of equity. Alternatively, the Commission found that it could find that it could determine that other evidence

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[294] *Id.* (citing *Emera Maine*, 854 F.3d at 30 (citing *Tenn. Gas Pipeline*, 926 F.2d at 1213) ("[Where] the utility at issue was riskier than the proxy group . . . the midpoint of the upper half was 'an obvious place to begin.'"); *Potomac-Appalachian Transmission Highline, LLC*, 158 FERC ¶ 61,050, at PP 270, 273 (2017) (setting ROE at the "measure of central tendency of the lower half of the zone of reasonableness . . . [g]iven [the utility's] low level of risk as compared to the proxy group.")).

[295] *Id.*

[296] *Id.* P 57 (citing *Emera Maine*, 854 F.3d at 26).

[297] *Id.* (citing *Emera Maine*, 854 F.3d at 26 (quoting *Papago Tribal Util. Auth. v. FERC*, 723 F.2d 950, 857 (D.C. Cir. 1983))).

convincingly demonstrates that the existing ROE is unjust and unreasonable despite it falling within that range.[298]

175. The Commission also explained that the base ROEs that fall within the applicable range of presumptively just and reasonable base ROEs will be presumed to be just and reasonable, and those that fall outside of the applicable range will be presumed to be unjust and unreasonable.[299] The Commission further found that those presumptions would only be rebuttable presumptions because the ultimate determination of whether an existing ROE is unjust and unreasonable still "depends on the particular circumstances of the case."[300] The Commission noted that other evidence regarding the particular circumstances of the case could rebut a presumption that applies, such as evidence regarding non-utility stock prices, investor expectations for non-utility stocks, various types of bond yields and their relation to stock prices, investor and other expert testimony, and testimony regarding the effects of rates on customers.[301]

B. Rehearing Requests

176. MISO TOs argue that, while the concept of a range of presumptively just and reasonable ROE values has merit, there are problems with the quartile approach used in Opinion No. 569. First, MISO TOs contend that the Commission never reconciles its concept of risk-associated sub-ranges with its long-standing rationale for using the midpoint to establish base ROEs for groups of utilities (i.e., to reflect such a group's broad range of risks). They contend that, while the midpoint rationale dovetails with *Emera Maine*'s recognition that "the zone of reasonableness creates a broad range of potentially lawful ROEs," the quartile approach of Opinion No. 569 does not. MISO TOs state that the Commission's historical reference to the midpoint explicitly recognizes the need to reflect the full range of required returns for a proxy group determined to be representative of a group of utilities such as the MISO TOs. But they contend that the Commission's attempt to further parse this composite zone uses an unexplained and arbitrary notion of relative risk based on arbitrary quartiles and is inconsistent with the Commission's own rationale for referencing the midpoint. Moreover, they assert that, as applied in Opinion No. 569, the effort lacks any foundation in case-specific evidence.[302]

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[298] *Id.* PP 61-62.

[299] *Id.* P 85.

[300] *Id.* P 68 (citing *Emera Maine*, 854 F.3d at 23).

[301] *Id.*

[302] MISO TOs Rehearing Request at 29.

177. In addition, MISO TOs contend that the Commission's new approach is inconsistent with the logic it uses to select the proxy group. They state that the proxy group is assembled using criteria which limit the proxies to companies that are considered to present investment risks comparable to those of the utility or group of utilities whose rates are at issue. Nevertheless, they argue, the Commission's quartile approach effectively truncates the zone of reasonableness by omitting from consideration the top one-eighth and the bottom one-eighth of the composite zone. They argue that the Commission's reasoning departs without explanation from the principle that every value in the zone of reasonableness is potentially a lawful ROE.[303]

178. MISO TOs further argue that the Commission derives its quartiles from the composite range of DCF and CAPM results but overlooks that different proxy companies' results are found at the low end, the middle, and the high end of each of the two analyses on which the Commission relies. Thus, MISO TOs assert, one or more proxies that fall within the "above average risk" quartile in the results of the DCF model appear in a different quartile of the CAPM results. MISO TOs argue that the Commission therefore cannot rationally distinguish "high risk" proxy companies from "low risk" proxies in its composite zone. They contend that the Commission has not provided an economic or financial rationale for the quartile approach.[304]

179. With regard to the Second Complaint, MISO TOs contend that there likewise is no need for a new ROE methodology to justify dismissal of the Second Complaint. According to MISO TOs, the upper midpoint of the Commission's IBES-based DCF analysis for the Second Complaint study period is only 9.83%, reflecting—just as in the First Complaint—anomalous capital market conditions. But they assert that alternative benchmark estimates and state ROE data demonstrate, as the Presiding Judge found, that the DCF outcome is unreliable. They argue that midpoint CAPM and Expected Earnings estimates (10.49% and 11.41%, respectively), as well as a Risk Premium estimate of 10.36%, establish that the Second Complaint record does not support a finding that the 10.32% base ROE determined in Opinion No. 551 was unjust and unreasonable for the Second Complaint study period.[305] They state that state-authorized ROEs for lower-risk integrated and distribution utilities further corroborate that conclusion, citing witness Lapson's national survey of state regulatory decisions in 2014-2015 that authorized base ROEs of 10% or more for retail utility operations in states within the MISO region.[306]

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[303] *Id.* at 29-30.

[304] *Id.* at 30.

[305] *Id.* at 35.

[306] *Id.* at 35-37.

180. MISO TOs state that, if the Commission continues to pursue Opinion No. 569's approach to using ranges of presumptively just and reasonable ROEs based on a portion of the zone of reasonableness, two alternative approaches would remedy the principal shortcoming of the Commission's quartile approach (i.e., its excision of the highest and lowest eighths of the composite zone). They state that this can be resolved either by dividing the entire zone of reasonableness into equal thirds, rather than quarters, or by using the upper and lower midpoints of the zone of reasonableness to segregate the three portions of the zone.[307]

181. Exelon argues that the Commission's ranges of presumptively just and reasonable ROEs are too narrow. Exelon contends that the Commission does not explain why it makes sense to treat only 25% of the range of investor expectations that is developed by the financial models as presumptively just and reasonable. Exelon asserts that the Commission already identifies a screened peer group with comparable risk to the subject utility when it selects a proxy group, and that it is unreasonable to adjust again for that same risk in determining quartiles for ranges of presumptively just and reasonable ROEs.[308]

182. Exelon also argues that there is no rationale for placing the top eighth and bottom eighth of the zone of reasonableness out of the ranges of presumptively just and reasonable ROEs. Exelon further contends that, while quartiles result in an even division, the Commission never justifies its use of quartiles.[309] In addition, Exelon asserts that the Commission's ranges of presumptively just and reasonable ROEs are so narrow that small proxy group changes, such as the exclusion of a proxy group company or a change in the performance of a particular proxy group company, could result in a utility's ROE changing from presumptively just and reasonable to presumptively unjust and unreasonable. Exelon argues that this will create rate instability that will chill investment.[310]

183. Exelon also disagrees with the Commission's conclusion in Opinion No. 569 that the use of ranges of presumptively just and reasonable ROEs does not change the burdens that apply in the context of section 206 complaints. Exelon contends that, under Opinion No. 569, an average risk utility whose base ROE is above the applicable range of presumptively just and reasonable ROEs bears the burden of overcoming a presumption that its ROE is unjust and unreasonable, which removes the burden on the complainant to

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[307] *Id.* at 38.

[308] Exelon Rehearing Request at 8-10.

[309] *Id.* at 10-11.

[310] *Id.* at 15-17.

demonstrate that such an ROE is unjust and unreasonable. Exelon asserts that this departure from section 206 is especially unreasonable because the upper and lower eighths of the zone of reasonableness can never be presumptively just and reasonable.[311]

184. Transource Energy argues that the full zone of reasonableness represents the broad range of potentially reasonable ROEs, as the court stated in *Emera Maine*, and thus that full zone presents the best evidence of what is a potentially lawful ROE, not a subzone within the overall zone. Transource Energy contends that the full zone of reasonableness already accounts for risk and contains comparable and representative companies. Transource Energy asserts that the Commission does not provide evidence justifying that there are identifiable distinctions in the risk profiles of firms that constitute the proxy group which fall neatly into quartiles. Transource Energy further argues that the Commission's exclusion of the top and bottom eighths of the zone of reasonableness ignore otherwise valid ROE estimates in the ranges of presumptively just and reasonable ROEs.[312]

185. CAPs argue that *Emera Maine* did not require the Commission to adopt a new methodology, but only to better explain Opinion No. 531's finding that the New England TOs' existing 11.14% base ROE was unjust and unreasonable.[313] If the Commission decides to adopt a new methodology, CAPs argue that the quartile approach is flawed. CAPs argue that the presumptively just and reasonable zones raise the customers' burden of proof to challenge ROEs that may have become unjust and unreasonable. CAPs assert that the presumptively just and reasonable zones are contrary to the customer protection principles embodied in the FPA and introduces an unlawful asymmetry between rate increases sought by utilities under section 205 of the FPA and rate reductions sought by customers under section 206 of the FPA.[314]

186. If the Commission keeps the presumptively just and reasonable zones, CAPs argue that the Commission should narrow these zones. They contend that the quartile approach results in unnecessarily broad presumptive zones. They reiterate their argument from their initial briefs that the Commission could narrow the presumptive immunity zones by, for example, establishing five risk groups:ver y-low risk; moderately low risk; average risk; moderately high risk; and very high risk. Under this approach, CAPs argue, the zones would be narrower, representing sextiles rather than quartiles of the composite

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[311] *Id.* at 19-22.

[312] Transource Energy Rehearing Request at 30-35.

[313] CAPs Rehearing Request at 12-16.

[314] *Id.* at 16.

range.[315] Regarding the Commission's statement that the quartile approach using three risk groups strikes an appropriate balance between the interests of customers and utilities, CAPs argue that the very establishment of presumptively just and reasonable zones already tilts the balance of interests in favor of shareholders.[316]

187. CAPs argue that the Commission did not explain why the "traditional" starting point for assessing risk is relevant or even preferable to a narrower and more precise definition of risk that would better protect customers. CAPs argue that it is possible to start the risk assessment at a point of central tendency within any sub-range of the zone of reasonableness. Furthermore, CAPs assert that the proximity of potentially lawful ROEs to the just and reasonable ROE does not render these ROEs presumably just and reasonable (i.e., ROEs within the zone of reasonableness that are close to the just and reasonable ROE may be a little less unjust and unreasonable, but remain unjust and unreasonable nonetheless). They argue that the courts have ruled that the just and reasonable standard does not permit "even a little unlawfulness."[317]

188. CAPs also argue that the notion of presuming the justness and reasonableness of ROEs close to the lawful ROE runs afoul of multiple rulings made by the court in *Emera Maine*: (1) it is arbitrary and capricious to assume that there are only three possible stopping points—lower midpoint, midpoint, and upper midpoint—on the continuum of "potentially just and reasonable" ROEs that lie within the range of adopted proxy results; (2) the fact that a rate falls within the zone of reasonableness does not establish that the rate is the just and reasonable rate for the utility at issue; and (3) whether a rate, even one within the zone of reasonableness, is unlawful depends on the particular circumstances of the case, and, therefore, requires that a numerical comparison of model results to an existing ROE be accompanied by a narrative explanation of what made a difference between the two unreasonable.[318] CAPs argue that, if the proximity of an ROE to the just and reasonable ROE does not conclusively prove the justness and reasonableness of an ROE, then such proximity cannot be used to infer that all ROEs that are close to the just and reasonable ROE within a certain range "may" be just and reasonable.[319]

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[315] *Id.* at 16-17.

[316] *Id*. at 17.

[317] *Id.* at 18 (citing *Consumers Fed'n of Am. v. FPC*, 515 F.2d 347, 358 n.64 (D.C. Cir. 1975) (quoting *FPC v. Texaco*, 417 U.S. 380, 399 (1974))).

[318] *Id*. at 18-19.

[319] *Id*. at 19-20.

189. RPGI asserts that, for average risk utilities, the midpoint of the zone of reasonableness is what the existing ROE must be compared to—not a range of presumptively just and reasonable ROEs—and any existing ROE that exceeds that midpoint should be presumed unjust and unreasonable. RPGI also contends that the use of ranges of presumptively just and reasonable ROEs contravenes the FPA's consumer protection purpose because it can insulate an existing ROE from a section 206 challenge even if, for example, an existing ROE for an average-risk group of utilities exceeds the midpoint. In addition, RPGI argues that, while the Commission states that the ranges of presumptively just and reasonable ROEs create only a rebuttable presumption, it is difficult to imagine the circumstances under which the presumption could be rebutted. RPGI asks the Commission to grant rehearing to reject the use of ranges of presumptively just and reasonable ROEs.[320]

C. Commission Determination

190. We grant rehearing and hold that the ranges of presumptively just and reasonable base ROEs will be calculated by dividing the overall composite zone of reasonableness into three equal portions. We are persuaded by the requests for rehearing that contend that the Commission's ranges of presumptively just and reasonable base ROEs should encompass the entire composite zone of reasonableness. The court in *Emera Maine* stated that "the zone of reasonableness creates a broad range of potentially lawful ROEs[,]"[321] and we now find that excluding the bottom eighth and top eighth of the overall zone of reasonableness, as the Commission's approach in Opinion No. 569 did, is inappropriate because it will ignore some "potentially lawful ROEs" when determining which ranges of ROEs should be considered presumptively just and reasonable. The ranges of presumptively just and reasonable base ROEs are intended to help inform the Commission's analysis under section 206 by identifying what subset of the "potentially lawful ROEs" for given utilities represents the range of base ROEs that would likely be just and reasonable for utilities of that risk profile. We find that it would be inappropriate to identify a subset of "potentially lawful ROEs" for given utilities without considering all of those potentially lawful ROEs.

191. We are further persuaded by arguments that it is inappropriate to exclude the bottom eighth and top eighth of the overall composite zone of reasonableness because even those portions of the overall composite zone of reasonableness are results from proxy group companies that have been screened using criteria which limit the proxies to companies that are considered to present investment risks comparable to those of the utility or group of utilities whose rates are at issue. We find that, when we have already

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[320] RPGI Rehearing Request at 9-16.

[321] *Emera Maine*, 854 F.3d at 26.

constructed a proxy group using limitations for comparable risk, it would be too restrictive to then construct ranges of presumptively just and reasonable base ROEs using only the results of some of those risk-screen proxy group companies. That initial proxy group screening process is intended to lead to the "broad range of potentially lawful ROEs" for a given utility or utilities, and we find that is more appropriate for the ranges of presumptively just and reasonable base ROEs to encompass the results from all of the proxy group companies that were identified in that process, rather than to exclude the results of the bottom eighth and top eighth of those results.

192. Exelon argues that the ranges of presumptively just and reasonable ROEs used in Opinion No. 569 are too narrow. MISO TOs make a similar argument, contending that the Commission's ranges of presumptively just and reasonable ROEs are inappropriate because they overlook that one or more proxies that fall within a particular risk profile range for one of the models used by the Commission may fall within a different risk profile range for a different model. CAPs make an opposing argument, asserting that the Commission's ranges are unnecessarily broad. We continue to find that using three risk groups strikes an appropriate balance between the interests of customers and utilities because they will be narrow enough to protect customers from unjust and unreasonable ROEs while also providing utilities and all market participants with an additional objective benchmark that the Commission will use to assess whether an ROE is likely unjust and unreasonable.[322] With respect to MISO TOs' argument that the ranges are inappropriate because the proxies that fall within a particular risk profile range for one of the models used by the Commission may fall within a different risk profile range for a different model, we find that this concern is addressed by averaging the results of the different models. We recognize that proxy group companies may fall within different risk profile ranges in different models, and this is why we average the results of those models. Indeed, this is a significant reason why we are considering different models and averaging their results—so that we can consider and give equal weight to the different results that are produced by these models, reflecting to a greater extent the models that investors consider.

193. Accordingly, we will continue to use three ranges of presumptively just and reasonable base ROEs and that they should be constructed by dividing the overall zone of reasonableness into three equal segments. This construction will include all of the "potentially lawful ROEs" in the zone of reasonableness in one of the ranges of presumptively just and reasonable base ROEs.

194. The Commission explained that its approach to constructing the ranges of presumptively just and reasonable base ROEs in Opinion No. 569 was based on the logic that the end points of a range for a given risk profile should be closer to the traditional

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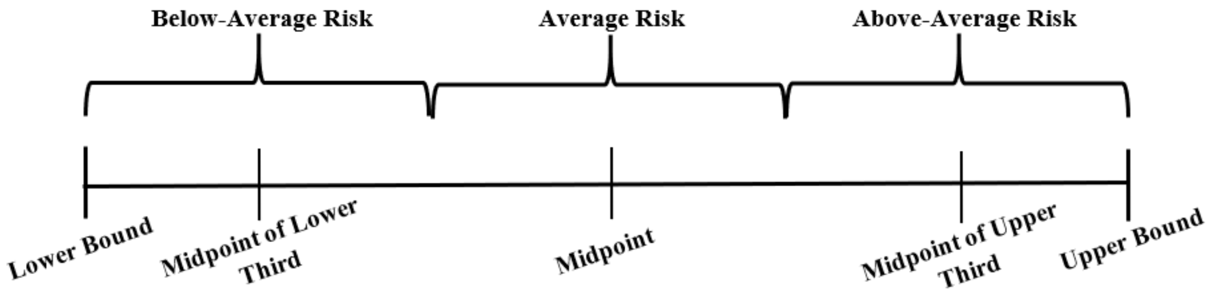
[322] *See id.* P 84.

starting point for analyzing the ROEs of utilities with that risk profile than they are to the traditional starting points for utilities with a different risk profile.[323] Upon further consideration, given our decision to use three ranges of presumptively just and reasonable base ROEs that together encompass the overall zone of reasonableness, we find it appropriate to modify the traditional starting points for below-average and above-average risk utilities to be the midpoint of the lower and upper thirds, respectively. Applying these new starting points, as well as the traditional midpoint of the zone of reasonableness starting point for average risk utilities, will ensure that the end points for all three risk profile ranges will be closer to the starting point for analyzing ROEs of utilities with each respective risk profile than they are to the starting points for utilities with different risk profiles. Below is an illustration of the overall composite zone of reasonableness divided into three equal ranges of presumptively just and reasonable base ROEs.

Figure 2: Ranges of Presumptively Just and Reasonable Base ROEs



195. Exelon asserts that the use of ranges of presumptively just and reasonable base ROEs removes the burden on the complainant to demonstrate that an existing base ROE is unjust and unreasonable when such a base ROE is above the applicable range of presumptively just and reasonable ROEs because the utility or utilities then bear the burden of overcoming a presumption that its ROE is unjust and unreasonable. CAPs make a similar argument in the opposite direction, contending that the presumptively just and reasonable zones raise the customers' burden of proof to challenge ROEs that may have become unjust and unreasonable. We find these arguments unavailing. As the

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[323] Opinion No. 569, 169 FERC ¶ 61,129 at P 63. Those traditional starting points were the midpoint of the zone of reasonableness for average risk utilities, the midpoint of the lower half of the zone for below-average risk utilities, and the midpoint of the upper half of the zone for above-average risk utilities.

Commission explained in Opinion No. 569,[324] the change to our ROE methodology to utilize ranges of presumptively just and reasonable ROEs does not change the burdens that parties face under section 206. It is merely an objective benchmark that will be used in our overall analysis of base ROEs to help determine if an existing rate has been shown to be unjust and unreasonable under section 206. It remains the case, as it was before implementing this modification to our ROE methodology, that "[t]he proponent of a rate change under section 206 . . . bears 'the burden of proving that the existing rate is *unlawful*.'"[325] The use of ranges of presumptively just and reasonable ROEs does not change this burden. Those ranges will merely serve to inform our assessment of ROEs. The fact that our use of those ranges will involve employing a rebuttable presumption does not change the burdens that apply.

196. MISO TOs and CAPs also take issue with the use of presumptively just and reasonable base ROEs because they assert that *Emera Maine* did not require the Commission to adopt the use of such ranges. As the Commission explained in Opinion No. 569,[326] the use of ranges of presumptively just and reasonable ROEs in our ROE methodology ensures that our determinations satisfy the requirements of the *Emera Maine* decision. The court in *Emera Maine* found that the Commission must "explain what circumstances" support its "actual finding as to the lawfulness" of an existing base ROE in a section 206 proceeding, and the use of ranges of presumptively just and reasonable base ROEs will allow us to do so in a structured manner. Using such ranges will produce a specific result from our risk profile determination—a rebuttable presumption—and then we will make an explicit finding as to whether the other evidence presented by the parties in the case has rebutted that presumption; therefore, this analysis will require us to "explain what circumstances" support our "actual finding as to the lawfulness" of an existing base ROE. Moreover, because risk profile is the particular circumstance most relevant to determining whether an existing ROE is unjust and unreasonable, using ranges of presumptively just and reasonable ROEs based on a utility's risk profile will ensure that the risk profile determination has a clear and significant connection to our ultimate finding relating to lawfulness. Accordingly, we continue to find that that the use of ranges of presumptively just and reasonable ROEs in our ROE methodology will ensure that our determinations satisfy the requirements of the *Emera Maine* decision.

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[324] *See id.* P 79.

[325] *Emera Maine*, 854 F.3d at 24 (emphasis in original) (quoting *Ala. Power Co. v. FERC*, 993 F.2d 1557, 1571 (D.C. Cir. 1993)).

[326] *See* Opinion No. 569, 169 FERC ¶ 61,129 at PP 70-71.

197. CAPs and RPGI assert that the use of ranges of presumptively just and reasonable base ROEs is inappropriate because any base ROE that exceeds the applicable base ROE produced by the Commission's analyses should be found unjust and unreasonable. We disagree. As the Commission stated in Opinion No. 569,[327] the court in *Emera Maine* rejected this approach, finding that the Commission must do more than simply identify a single ROE from its own analysis and then determine if the existing ROE is unjust and unreasonable based on whether it exceeds that single ROE. Accordingly, we affirm the Commission's finding that it should not continue to follow the approach that was reversed in *Emera Maine* of identifying a single cost of equity result and then finding that an existing ROE is unjust and unreasonable under prong one of section 206 if it exceeds that cost of equity.

198. CAPs also reiterate their argument that the use of ranges of presumptively just and reasonable base ROEs creates an unlawful asymmetry between rate increases sought by utilities under section 205 and rate reductions sought by customers under section 206. We disagree and affirm the Commission's finding that the use of presumptively just and reasonable ranges does not create any such unlawful asymmetry.[328] As the Commission explained, the showing that is required under section 206 differs from the showing that is required under section 205. The D.C. Circuit explained that "[t]he purpose of section 206 is 'quite different' from that of section 205,"[329] "[s]ection 206's procedures are 'entirely different' and 'stricter' than those of section 205," and that, while "[a] utility filing a rate adjustment under section 205 must show that the adjustment is *lawful* . . . [t]he proponent of a rate change under section 206 [] bears 'the burden of proving that the existing rate is *unlawful*.'"[330] The Commission does not have the authority to change those standards and our modification of the Commission's ROE methodology to use ranges of presumptively just and reasonable ROEs adheres to those standards; therefore, we reject CAPs' argument on this point.

199. We also are not persuaded by CAPs' argument that the use of ranges of presumptively just and reasonable base ROEs is inconsistent with other rulings made by the court in *Emera Maine*. Contrary to CAPs' assertion, the use of such ranges does not assume that there are only three possible stopping points—lower midpoint, midpoint, and upper midpoint—on the continuum of "potentially just and reasonable" ROEs. In fact, it

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[327] *See id.* P 73.

[328] *See id.* P 74.

[329] *Emera Maine*, 854 F.3d at 24 (quoting *City of Winnfield, La. v. FERC*, 744 F.2d 871, 875 (D.C. Cir. 1984)).

[330] *Id.* (emphasis in original) (quoting *Ala. Power Co. v. FERC*, 993 F.2d 1557, 1571 (D.C. Cir. 1993)).

does the opposite—it recognizes that there may be more than one just and reasonable return and employs ranges of just and reasonable ROEs to help determine if a particular existing base ROE is just and reasonable in light of the overall composite zone of reasonableness and the risk profile of the utilities at issue. The use of presumptively just and reasonable ranges also does not find that if a rate falls within the zone of reasonableness, then it is just and reasonable, as CAPs suggest. As described above, the fact that a rate falls within the zone of reasonableness will not result in a finding that such a rate is just and reasonable. In fact, it is possible that a rate that falls within the overall zone, but outside of the applicable presumptively just and reasonable range, would be presumed unjust and unreasonable. Similarly, whether an existing ROE is unjust and unreasonable, even one that falls within the applicable range of presumptively just and reasonable ROEs, still "depends on the particular circumstances of the case."[331] Accordingly, if an existing ROE falls within the applicable range of presumptively just and reasonable ROEs, the presumption that the ROE is just and reasonable is a rebuttable presumption. Therefore, other evidence regarding the particular circumstances of the case can demonstrate that an existing ROE is unjust and unreasonable even if it falls within the applicable range of presumptively just and reasonable ROEs, such as evidence regarding non-utility stock prices, investor expectations for non-utility stocks, various types of bond yields and their relation to stock prices, investor and other expert testimony, and testimony regarding the effects of rates on customers.

XV. Acting in these Proceedings as Opposed to in Base ROE NOI Proceeding

A. Rehearing Requests

200. Parties on rehearing argue that, because the Commission has sought public input on the Commission's base ROE policy from all interested parties in the Base ROE NOI proceeding,[332] it would be inappropriate for the Commission to establish a new base ROE policy in these MISO ROE proceedings without considering the broader universe of comments and evidence submitted in response to the Base ROE NOI.

201. Specifically, Exelon states that the thousands of pages of comments from utilities, industry groups, and other interested parties provided the Commission with a wide range of perspectives and valuable data. Exelon, MISO TOs, and Ameren argue that promulgating a new ROE method in an individual proceeding ignores the evidence submitted in the Base ROE NOI docket.[333] Moreover, Exelon, Transource Energy, and

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[331] *Id.*

[332] Base ROE NOI, 166 FERC ¶ 61,207.

[333] Exelon Rehearing Request at 27; *see also* MISO TOs Rehearing Request at 56-57; Ameren Rehearing Request at 27.

Ameren explain that, in the Base ROE NOI proceeding, the Commission specifically sought comments regarding the ROE four-financial model approach and, therefore, those parties participating in the Base ROE NOI proceeding did not address the new ROE two-model method that was introduced in Opinion No. 569 or the potential issues with the ROE four-model financial model approach revealed in Opinion No. 569.[334] Exelon and Ameren comment that establishing a new base ROE policy in these proceedings, as opposed to the Base ROE NOI proceeding, is inappropriate because the Commission's actions here will not reflect the input and evidence that was provided in the Base ROE NOI proceeding by other stakeholders who are not parties to these proceedings.[335] Exelon argues that the Commission should not rely on the fact that an outcome is reasonable as applied to this group of transmission owners, without analyzing the potential outcomes that will result from wider application of this method.[336] Transource Energy recognizes that the Commission has some discretion to enact policies through adjudication. However, it contends that under this set of circumstances the Commission's reliance on an adjudication and not the pending Base Roe NOI "amounts[s] to an abuse of discretion" that violates the Administrative Procedure Act.[337]

202. MISO TOs also assert that the Commission does not engage in reasoned decision-making when it disregards relevant evidence available to it, even if the evidence is in a different docket,[338] and it would be arbitrary and capricious for the Commission to set an industry-wide, binding precedent while ignoring this evidence.[339] Accordingly, MISO TOs argue that the Commission should take official notice in this proceeding of pertinent evidence introduced in the NOI docket.[340] MISO TOs state that the Commission's generic, industry-wide NOI on the methodology for determining base ROEs provides a more logical and reasonable forum for the Commission to develop, with

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[334] Exelon Rehearing Request at 27-28; Transource Energy Rehearing Request at 36-37; Ameren Rehearing Request at 24.

[335] Exelon Rehearing Request at 5, 12, 27; Ameren Rehearing Request at 24.

[336] Exelon Rehearing Request at 27.

[337] Transource Energy Rehearing Request at 37 (quoting *NLRB v. Bell Aerospace Co.*, 416 U.S. 267, 294 (1974)).

[338] MISO TOs Rehearing Request at 55.

[339] *Id.* at 58.

[340] *Id.* at 55.

the benefit of the extensive stakeholder input it solicited, any changes to its ROE methodology that it may find to be appropriate.[341]

203. Ameren argues that the fact that the Commission has left open the generic NOI docket, while at the same time making an industry-wide policy change in this adjudicated proceeding, constitutes arbitrary and capricious agency decision-making.[342]

204. Finally, Exelon asserts that the Commission should limit the application of any new method for assessing base ROEs adopted by Opinion No. 569 to these MISO cases and clarify that the Commission is not prejudging the application of any new method to other utilities.[343]

B. Commission Determination

205. We are not persuaded that it is inappropriate for the Commission to establish a new base ROE policy in these MISO complaint proceedings when it has also issued the Base ROE NOI to obtain input on this topic from interested parties. The Commission "has substantial discretion to establish rules of general application by case-specific adjudication and is not restricted to the use of a separate generic proceeding"[344] to

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[341] *Id*. at 37.

[342] Ameren Rehearing Request at 24.

[343] Exelon Rehearing Request at 28.

[344] Opinion No. 569, 169 FERC ¶ 61,129 at P 449 (quoting *Procedures for Disposition of Contested Audit*, Order No. 675, 114 FERC ¶ 61,178, at P 32 (2006). *See also NLRB v. Bell Aerospace Corp*., 416 U.S. 267, 294 (1974) ("[A]djudicative cases may and do serve as vehicles for the formulation of agency policies."); *SEC v. Chenery Corp*., 332 U.S. 194, 203 (1974) ("[T]he choice made between proceeding by general rule or by individual, ad hoc litigation is one that lies primarily in the informed discretion of the administrative agency."); *Michigan-Wisconsin Pipeline Co. v. FPC*, 520 F.2d 84, 89 (D.C. Cir. 1975) ("[T]here is no question that the Commission may attach precedential and even controlling weight to principles developed in one proceeding and then apply them under appropriate circumstances in a stare decisis manner."); *Pac. Gas and Electric Co. v. FPC*, 506 F.2d. 33, 38 (D.C. Cir. 1974) ("[A]gency may establish binding policy through rulemaking procedures . . . or through adjudications which constitute binding precedents."); *AEP Power Mktg., Inc*., 108 FERC ¶ 61,026, at P 187 (2004) ("Our decision to establish new policy in the context of case-specific proceedings is clearly within our authority."); *Investigation of Terms and Conditions of Public Utility Market-Based Rate Authorizations*, 103 FERC ¶ 61,349, at P 51 (2003) ("The Commission, moreover, is not limited to notice and comment rulemaking to develop

establish such rules. The Commission similarly has explained that "[o]ur decision to establish new policy in the context of case-specific proceedings is clearly within our authority."[345] Thus, while the Commission issued the Base ROE NOI, this did not prohibit it from changing its base ROE policy in an adjudication nor require that changes in base ROE policy occur in that Base ROE NOI proceeding. Importantly, we note that the due process protections afforded to all parties to these proceedings are available to every party to Commission proceedings. Any party in other proceedings will be free to argue, just as the parties to these proceedings were, that the base ROE methodology applied in any of these proceedings should be modified or applied differently because of the specific facts and circumstances of the proceeding involving that party.

XVI. Complaint-Specific Results: First Complaint

206. As discussed in this order, we are revising the methodology for determining whether an existing ROE is unjust and unreasonable and, if so, what is a just and reasonable ROE pursuant to section 206 of the FPA. Applying this methodology to the First Complaint proceeding, we continue to find that the rate to be reviewed in that proceeding— MISO TOs' 12.38% ROE—is unjust and unreasonable. Having addressed the first prong of the Commission's dual burden under section 206 and thus satisfied the "condition precedent"[346] to exercising our authority to change a rate under section 206, we grant rehearing of Opinion No. 569 and find that a just and reasonable replacement ROE for MISO TOs in the First Complaint proceeding is 10.02% under the second prong of section 206.

207. Below we address the "specific findings"[347] as to the "'particular circumstances'"[348] of the First Complaint proceeding that establish "'a rational connection'"[349] between the record evidence in that proceeding and our decisions under both prongs of section 206 herein to establish that we have "'made a principled and

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policy. Agencies generally are permitted considerable discretion to choose whether to proceed by rulemaking or by adjudication.")).

[345] *AEP Power Mktg*., 107 FERC ¶ 61,018, at P 199 (2004).

[346] *Emera Maine*, 854 F.3d at 25 (citing *FPC v. Sierra Pac. Power*, 350 U.S. 348, 353 (1956)).

[347] *Id.* at 30.

[348] *Id.* at 27 (citing *FPC v. Nat. Gas Pipeline Co.*, 315 U.S. 575, 586 (1942)).

[349] *Id.* at 28 (citing *FERC v. Elec. Power Supply Ass'n*, 136 S.Ct. 760, 782 (2016)).

reasoned decision supported by the evidentiary record.'"[350] The Commission bases its decisions concerning just and reasonable ROEs for public utilities on the most recent information in the record regarding market cost of equity. Consequently, the starting point for determining whether MISO TOs' existing ROE has become unjust and unreasonable must be a consideration of whether the current market cost of equity has changed since the MISO TOs' existing ROE was established based on financial data for the six months ending February 2002, such that the existing base ROE is no longer just and reasonable. Accordingly, we begin by determining a composite zone of reasonableness using the most recent financial information in the record of the First Complaint proceeding. We continue to find that the appropriate study period including this most recent financial information is the first six months of 2015.[351]

A. DCF Analysis

208. In Opinion No. 569, the Commission affirmed Opinion No. 551's approval of the Presiding Judge's DCF analysis, with one exception. In Opinion No. 569, the Commission held that only the IBES short-term growth projection should be used for calculating the (1+.5g) adjustment to the dividend yield, instead of the composite growth rate including both short- and long-term growth rates that was used by the Presiding Judge. Here, we affirm the Commission's holding on that issue and the Commission's use of the low-end outlier test applied in Opinion No. 569. Accordingly, our determinations on those issues do not result in any changes to the DCF analysis that was used in Opinion No. 569 for the First Complaint proceeding.

209. As discussed above, we grant rehearing of Opinion No. 569 to modify the high-end outlier test that was used there to now treat any proxy company as high-end outlier if its cost of equity estimated under the model in question is more than 200% of the median result of all of the potential proxy group members in that model before any high or low-end outlier test is applied, subject to a "natural break" analysis. The Commission explained in Opinion No. 569 that applying the version of the high-end outlier test that was used there did not result in the exclusion of any company from the DCF proxy group as a high-end outlier.[352] The high-end outlier test as modified in this order also does not result in any exclusions. Accordingly, our determination on this issue also does not result in any changes to the DCF analysis that was used in Opinion No. 569. We also grant rehearing of Opinion No. 569 to find that the long-term growth rate should be given 20% weighting and the short-term growth rate 80% weighting in the two-step

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[350] *Id.* at 30 (citing *S. Cal. Edison v. FERC*, 717 F.3d at 181).

[351] *See* Opinion No. 569, 169 FERC ¶ 61,129 at P 460; Opinion No. 551, 156 FERC ¶ 61,234 P 19.

[352] Opinion No. 569, 169 FERC ¶ 61,129 at P 512.

DCF model. Our DCF analysis in the First Complaint proceeding reflecting this finding is shown in Appendix II to this order. Based on these determinations, we conclude that the DCF zone of reasonableness is 6.97% to 12.07%.

B. CAPM Analysis

210. In Opinion No. 569, the Commission affirmed Opinion No. 551's approval of the Presiding Judge's CAPM analysis in the First Complaint proceeding, with two exceptions related to the market risk premium. The Commission held that only the IBES short-term growth projection should be used in the one-step DCF analysis of the dividend paying members of the S&P 500, instead of the average of the IBES and *Value Line* growth projections approved by the Presiding Judge.[353] In addition, the Commission held that companies with negative ROEs or ROEs above 20% should be excluded from that analysis.[354]

211. As discussed above in section IV.C.1, we grant rehearing of Opinion No. 569 to, in future proceedings, consider the use of *Value Line* short-term growth rate projections in the one-step DCF analysis of the dividend paying members of the S&P 500 that is conducted in the CAPM. However, we find that the record is insufficient to allow us to use only *Value Line* short-term growth rates in the CAPM in the First Complaint proceeding. In addition, we affirm the Commission's application of the low-end outlier test and grant rehearing to modify the high-end outlier test, as described above. As the Commission explained in Opinion No. 569, the application of the low-end outlier test and the version of the high-end outlier that was used there did not result in the exclusion of any company from the CAPM proxy group.[355] The low-end outlier test and the modified high-end outlier test adopted herein also do not result in the exclusion of any company from the CAPM proxy group. Accordingly, we will continue to use the CAPM analysis that was relied upon in Opinion No. 569 for the First Complaint proceeding.[356] Based on these determinations, we conclude that the CAPM zone of reasonableness is 7.80% to 13.09%.

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[353] Opinion No. 551, 156 FERC ¶ 61,234 at PP 169, 172.

[354] Opinion No. 569, 169 FERC ¶ 61,129 at P 513.

[355] *See id.* PP 514-515.

[356] *See id.* P 513. The results of this CAPM analysis are reflected in page 6 of Attachment A to Trial Staff's Initial Briefs. *See* Trial Staff Initial Br. (II), Attachment A to App. 2 at 6.

C. Risk Premium Analysis

212. As discussed above, we grant rehearing of Opinion No. 569 to find that the Risk Premium Model should be used in our ROE analysis under section 206 of the FPA. As described above, we adopt modifications to the Risk Premium analysis that was provided by MISO TOs in the record for the First Complaint proceeding. Appendix I to this order shows the results of the Risk Premium Model, as applied with modifications adopted herein.

213. This Risk Premium Model produces an ROE result of 10.10%.[357] As further discussed above, we will impute a zone of reasonableness from the ROE produced by the Risk Premium model for purposes of using the Risk Premium model in our analysis under the first prong of section 206. We do so by applying the average of the widths of the zones of reasonableness from the CAPM and DCF models to the ROE produced by the Risk Premium model, with that ROE serving as the measure of central tendency of the zone of reasonableness. In the First Complaint proceeding, the result of the Risk Premium Model is 10.10% and the average width of the zones of reasonableness produced by the CAPM and DCF models is 520 basis points. Applying this value to the Risk Premium result to impute a zone of reasonableness results in a Risk Premium zone of reasonableness of 7.50% to 12.70%.[358]

D. Composite Zone of Reasonableness and Section 206 Findings

214. Averaging the top and bottom of the DCF, CAPM, and Risk Premium zones of reasonableness determined above based on financial data for the first six months of 2015 produces a composite zone of reasonableness in the First Complaint proceeding of 7.42% to 12.62%. The midpoint of that zone of reasonableness is 10.02%.

215. Having determined the composite zone of reasonableness based on financial data for the first half of 2015, we now turn to considering whether the MISO TOs' 12.38% ROE, which was determined based on financial data for the six months ending February 2002, may be found unjust and unreasonable pursuant to the first prong of section 206. In this order, we affirm the Commission's decision in Opinion No. 569 to use ranges of presumptively just and reasonable ROEs based on the risk profile of the MISO TOs to inform our decision whether their ROE has become unjust and unreasonable. However, as discussed above, we grant rehearing of Opinion No. 569 to find that those ranges should be calculated by dividing the overall composite zone of reasonableness into equal thirds.

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[357] *See* Appendix I.

[358] *Id.*

216. We affirm the Commission's determination in Opinion No. 569 that the MISO TOs should be treated as of average risk for purposes of determining the range of presumptively just and reasonable ROEs applicable to the MISO TOs.[359] In light of this determination, we find that the range of presumptively reasonable ROEs for consideration in determining whether MISO TOs' base ROE of 12.38% ROE in the First Complaint proceeding is unjust and unreasonable should be the middle third of the zone of reasonableness based on the revised construction of the presumptively just and reasonable zones adopted in this order. In the First Complaint proceeding, that range is from 9.15% to 10.89%.[360]

217. The MISO TOs' 12.38% is 149 basis points above the range of presumptively just and reasonable ROEs for the MISO TOs. Accordingly, we find that it is presumptively unjust and unreasonable. It is thus clear that, in light of our estimate of the cost of capital, the MISO TOs' 12.38% ROE is well outside any possible range of potentially just and reasonable ROEs for the MISO TOs. In order to rebut the presumption that the ROE is unjust and unreasonable, we would look at other evidence, such as state ROEs, ROEs of non-utility companies, ROEs produced by other methodologies, non-utility stock prices, investor expectations for non-utility stocks, various types of bond yields and their relation to stock prices, investor and other expert testimony, or testimony regarding the effects of rates on customers that would indicate that this is not the case. However, the record lacks such evidence sufficient to rebut the presumption. For example, the evidence in the record regarding state ROEs indicates that all state-authorized ROEs during the period April 1, 2013 through March 31, 2015 for integrated electric utilities providing generation, transmission, and distribution services ranged from 9.5% to 10.4% and that 87.34% of state-authorized ROEs for both integrated electric utilities and distribution-only electric utilities during that period were within this range.[361] The fact that MISO TOs' 12.38% ROE is 198 basis points above this range further demonstrates that MISO TOs' 12.38% ROE is unjust and unreasonable. In these circumstances, we find under the first prong of section 206 that the MISO TOs' 12.38% ROE that is the subject of the First Complaint proceeding has become unjust and unreasonable.

218. Having found that the MISO TOs' existing ROE is unjust and unreasonable, we turn to the establishment of a just and reasonable replacement ROE under the second prong of section 206. As discussed above, we have found that the midpoint of the composite zone of reasonable ROEs based on the most recent financial information in the record of the First Complaint proceeding is 10.02%. As discussed above, we find that the

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[359] *See id.* PP 518-521.

[360] *See* Appendix III.

[361] *See, e.g.*, Opinion No. 551, 156 FERC ¶ 61,234 at P 240.

MISO TOs are of average risk. Our policy is to set an RTO-wide ROE at the midpoint of the zone of reasonableness when the transmission owners receiving the RTO-wide ROE are of average risk. Accordingly, we find that the just and reasonable replacement ROE for the MISO TOs in the First Complaint proceeding is 10.02%. We therefore grant rehearing of Opinion No. 569 in part to require the MISO TOs to adopt a 10.02% ROE effective September 28, 2016, the date Opinion No. 551 required the MISO TOs to adopt a 10.32% ROE.

XVII. Complaint Specific Results: Second Complaint

A. Existing Rate for Purposes of Second Complaint and Overview

219. As discussed further below, we affirm the Commission's finding in Opinion No. 569 that the 10.02% base ROE established in the First Complaint proceeding is the existing rate to be reviewed for purposes of the Second Complaint proceeding because that is the rate which we would have to find unjust and unreasonable under the first prong of section 206 of the FPA, before we could require a new ROE "to be thereafter observed" pursuant to the second prong of section 206. As the Commission explained in Opinion No. 569, any new just and reasonable rate that we require "to be thereafter observed" pursuant to section 206(a) will replace the currently effective rate, not some previously effective rate. Accordingly, in order to determine a new rate to be thereafter observed, we must examine what the currently effective rate is because that is the rate that will need to be replaced if it is unjust and unreasonable. As discussed in the preceding section, in the First Complaint proceeding, we require MISO TOs to reduce their ROE to 10.02% effective prospectively from September 28, 2016. Therefore, that is the MISO TOs' currently effective ROE when we are deciding whether MISO TOs' ROE is unjust and unreasonable and should be modified prospectively pursuant to section 206 in the Second Complaint proceeding.

220. As discussed in this order, we are revising the methodology for determining whether an existing ROE is unjust and unreasonable and, if so, what is a just and reasonable ROE pursuant to section 206. Applying this methodology to the Second Complaint proceeding, we continue to find that the rate to be reviewed in that proceeding— 10.02% base ROE established in the First Complaint proceeding—has not been shown to be unjust and unreasonable.

221. Below we address the "specific findings"[362] as to the "'particular circumstances'"[363] of the Second Complaint proceeding that establish "'a rational

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[362] *Emera Maine*, 854 F.3d at 30.

[363] *Id.* at 27 (citing *FPC v. Nat. Gas Pipeline Co.*, 315 U.S. 575, 586 (1942)).

connection'"[364] between the record evidence in that proceeding and our decisions under both prongs of section 206 herein to establish that we have "'made a principled and reasoned decision supported by the evidentiary record.'"[365] Because the Commission bases its decisions concerning just and reasonable ROEs for public utilities on the most recent information in the record regarding market cost of equity, the starting point for determining whether the MISO TOs' existing ROE has become unjust and unreasonable must be a consideration of whether the current market cost of equity has changed such that the 10.02% base ROE established in the First Complaint proceeding is unjust and unreasonable. Accordingly, we begin by determining a composite zone of reasonableness using the most recent financial information in the record of the Second Complaint proceeding. We continue to find that the appropriate study period including this most recent financial information is July 1, 2015 through December 31, 2015.[366]

B. DCF Analysis

222. In Opinion No. 569, the Commission affirmed the Presiding Judge's DCF analysis in Initial Decision (II) with one exception. The Commission held that only the IBES short-term growth projection should be used for calculating the (1+.5g) adjustment to the dividend yield, instead of the composite growth rate including both short- and long-term growth rates that was used by the Presiding Judge. Here, we affirm the Commission's holding on that issue and the Commission's use of the low-end outlier test applied in Opinion No. 569. Accordingly, our determinations on those issues do not result in any changes to the DCF analysis that was used in Opinion No. 569 for the Second Complaint proceeding.

223. As discussed above, we grant rehearing of Opinion No. 569 to modify the high-end outlier test that was used there. The Commission explained in Opinion No. 569 that applying the version of the high-end outlier test that was used there did not result in the exclusion of any company from the DCF proxy group as a high-end outlier.[367] The high-end outlier test as modified in this order also does not result in any exclusions. Accordingly, our determination on this issue also does not result in any changes to the DCF analysis that was used in Opinion No. 569. We also grant rehearing of Opinion No. 569 to find that the long-term growth rate should be given 20% weighting and the short-term growth rate 80% weighting in the two-step DCF model. Our DCF analysis in the Second Complaint proceeding reflecting this finding is shown in Appendix II to this

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[364] *Id.* at 28 (citing *FERC v. Elec. Power Supply Ass'n*, 136 S.Ct. 760, 782 (2016)).

[365] *Id.* at 30 (citing *S. Cal. Edison v. FERC*, 717 F.3d at 181).

[366] *See* Opinion No. 569, 169 FERC ¶ 61,129 at P 524.

[367] *Id.* P 554.

order. Based on these determinations, we conclude that the DCF zone of reasonableness is 7.37% to 11.37%.

C. CAPM Analysis

224. In Opinion No. 569, the Commission affirmed the Presiding Judge's CAPM analysis in the Second Complaint proceeding, with one exception related to the market risk premium. The Commission held that only the IBES short-term growth projection should be used in the one-step DCF analysis of the dividend paying members of the S&P 500, which was consistent with the Presiding Judge's approach in Initial Decision (II).[368] In addition, the Commission held that companies with negative ROEs or ROEs above 20% should be excluded from that analysis.[369]

225. As discussed above in section IV.C.1, we grant rehearing of Opinion No. 569 to, in future proceedings, consider the use of *Value Line* short-term growth rate projections in the one-step DCF analysis of the dividend paying members of the S&P 500 that is conducted in the CAPM. However, we find that the record is insufficient to allow us to use only *Value Line* short-term growth rates in the CAPM in the Second Complaint proceeding. In addition, we affirm the Commission's application of the low-end outlier test and grant rehearing to modify the high-end outlier test as described above. As the Commission explained in Opinion No. 569, the application of the low-end outlier test and the version of the high-end outlier test that was used there did not result in the exclusion of any company from the CAPM proxy group.[370] The low-end outlier test and modified high-end outlier test adopted herein also do not result in the exclusion of any company from the CAPM proxy group. Accordingly, we will continue to use the CAPM analysis that was relied upon in Opinion No. 569 for the Second Complaint proceeding.[371] Based on these determinations, we conclude that the CAPM zone of reasonableness is 8.35% to 12.63%.

D. Risk Premium Analysis

226. As discussed above, we grant rehearing of Opinion No. 569 to find that the Risk Premium Model should be used in our ROE analysis under section 206 of the FPA. As

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[368] *See* Initial Decision (II), 155 FERC ¶ 63,030 at P 412.

[369] Opinion No. 569, 169 FERC ¶ 61,129 at P 555.

[370] *See id.* PP 556-557.

[371] *See id.* P 513. The results of this CAPM analysis are reflected in page 6 of Attachment A to Trial Staff's Initial Briefs. *See* Trial Staff Initial Br. (II), Attachment A to App. 2 at 6.

described above, we are adopting modifications to the Risk Premium analysis that was provided by the MISO TOs in the record for the Second Complaint proceeding. Appendix I of this order shows the results of the Risk Premium Model, as applied with modifications adopted herein.

227. This Risk Premium analysis produces an ROE result of 10.29%.[372] As further discussed above, we find that we will impute a zone of reasonableness from the ROE produced by the Risk Premium model for purposes of using the Risk Premium model in our analysis under the first prong of section 206. We do so by applying the average of the widths of the zones of reasonableness from the CAPM and DCF models to the ROE produced by the Risk Premium model, with that ROE serving as the measure of central tendency of the zone of reasonableness. In the Second Complaint proceeding, the result of the Risk Premium analysis is 10.29% and the average width of the zones of reasonableness produced by the CAPM and DCF models is 414 basis points. Applying this value to the Risk Premium result to impute a zone of reasonableness results in a Risk Premium zone of reasonableness of 8.22% to 12.36%.[373]

E. Composite Zone of Reasonableness and Section 206 Findings

228. Averaging the top and bottom of the DCF, CAPM, and Risk Premium zones of reasonableness determined above based on the most recent financial data in the record of the Second Complaint proceeding produces a composite zone of reasonableness in the Second Complaint proceeding of 7.98% to 12.12%. The midpoint of that zone of reasonableness is 10.05%.

229. The applicable range of presumptively just and reasonable ROEs for the MISO TOs in the Second Complaint proceeding is from 9.36% to 10.74%. As discussed above, the issue to be addressed in the Second Complaint is whether the ROE established in the First Complaint remains just and reasonable during the applicable test period as addressed by the evidence presented by the participants in the Second Complaint. The MISO TOs' 10.02% ROE established upon resolution of the First Complaint proceeding falls within the range of presumptively just and reasonable ROEs that applies in the Second Complaint. We find that this presumption has not been rebutted by the evidence in the Second Complaint proceeding. We see no evidence in the record, such as state ROEs, ROEs of non-utility companies, and other methodologies that rebuts this presumption. Accordingly, we do not find that the MISO TOs' ROE established in the First Complaint proceeding and in effect as of the date of this order is unjust and unreasonable under the first prong of section 206. For that reason, we do not establish a

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[372] *See* Appendix I.

[373] *Id.*

new just and reasonable ROE in the Second Complaint proceeding to be in effect prospectively from the date of this order.

XVIII. Refund Issues

A. Opinion No. 569

230. In Opinion No. 569, the Commission granted rehearing of Opinion No. 551 in part, found that the challenged 12.38% base ROE in the First Complaint proceeding was unjust and unreasonable, and additionally found that a replacement base ROE of 9.88% was just and reasonable—instead of the 10.32% replacement ROE that was set in Opinion No. 551. The Commission made the 9.88% ROE effective as of September 28, 2016, the date on which Opinion No. 551 was issued.[374] The Commission ordered MISO and the MISO TOs to provide refunds, with interest calculated pursuant to 18 C.F.R. § 35.19a, for the 15-month refund period for the First Complaint proceeding from November 12, 2013 through February 11, 2015 and for the period from September 28, 2016—the date on which Opinion No. 551 was issued—to the date of Opinion No. 569.[375]

231. The Commission then found that the 9.88% base ROE established in the First Complaint proceeding was the existing rate to be analyzed for purposes of the Second Complaint proceeding. In brief, the Commission reasoned that, for purposes of deciding whether a rate charged by a utility is unjust and unreasonable and determining a new just and reasonable rate "to be thereafter observed" pursuant to section 206(a) of the FPA, it must assess whether the public utility's currently effective rate is unjust and unreasonable, not some earlier rate that may have been in effect when the complaint was filed but has now been superseded. The Commission explained that, in other words, in order to determine a new rate to be thereafter observed, it must examine the currently effective rate because that is the rate that will need to be replaced if it is unjust and unreasonable. The Commission then explained that, because the 9.88% base ROE established in the First Complaint proceeding is effective prospectively from September 28, 2016, that is the currently effective rate that the Commission would have to find unjust and unreasonable under the first prong of section 206, before we could require a new ROE "to be thereafter observed" pursuant to the second prong of section 206.[376]

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[374] *See* Opinion No. 569, 169 FERC ¶ 61,129 at P 20.

[375] *Id.* at ordering para. (B).

[376] *Id.* P 530.

232. The Commission then concluded that the 9.88% ROE was just and reasonable based on the facts and circumstances of the Second Complaint and therefore dismissed the Second Complaint. The Commission then found that section 206 dictates that refunds may be ordered in a complaint proceeding only when the Commission grants prospective relief in that proceeding (i.e., the Commission sets a new just and reasonable rate which it "orders to be thereafter observed and in force.").[377] The Commission concluded that it could not order refunds for the Second Complaint proceeding's refund period because it was dismissing the complaint and not granting any prospective relief. The Commission found that ordering refunds in the Second Complaint proceeding despite the fact that it was granting no prospective relief would exceed the statutory authority in section 206 because it would effectively extend the 15-month refund period for the First Complaint since the refunds would be based on the relief granted in the First Complaint and not any action taken in the Second Complaint.

B. First Complaint Proceeding Refunds

1. Rehearing Requests

233. MISO TOs argue that the Commission erred in directing refunds for the period from September 28, 2016, through the date of Opinion No. 569 based on the new ROE set in the First Complaint proceeding. MISO TOs contend that the effective date of the new base ROE resulting from resolution of the First Complaint proceeding should be November 21, 2019, the date on which Opinion No. 569 was issued. MISO TOs acknowledge that, in cases of legal error, the proper remedy is one that puts the parties in the position they would have been in had the error not been made, but they assert that this is not a case of legal error because Opinion No. 569's adoption of a new ROE methodology goes beyond what is necessary to fix the problems identified by the *Emera Maine* court. MISO TOs contend that the court merely found that the Commission never explained how its ultimate placement of the base ROE was just and reasonable and that the Commission could correct this error by better tying the 10.32% base ROE set in Opinion No. 551 to the evidence in the record, rather than adopting a new base ROE methodology.[378] MISO TOs maintain that, therefore, the Commission's adoption of the 9.88% ROE for the First Complaint proceeding in Opinion No. 569 does not remedy a legal error.[379]

234. MISO TOs further argue that this is also not a case where the Commission fixed an error on rehearing of Opinion No. 551. They contend that, while the Commission

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[377] *Id.* P 568.

[378] MISO TOs Rehearing Request at 84-85 (citing *Emera Maine*, 854 F.3d at 28).

[379] *Id.*

"grant[ed] rehearing of Opinion No. 551 in part to require the MISO TOs to adopt a 9.88% ROE effective September 28, 2016, the date Opinion No. 551 required the MISO TOs to adopt a 10.32% ROE,"[380] it is unclear as to which issue presented on rehearing the Commission actually granted. MISO TOs assert that none of the rehearing requests asked the Commission to adopt a new ROE methodology, and instead opposing parties requested rehearing on the grounds that the composition of the DCF proxy group was incorrect, and that Commission should consider only DCF results, ignore the anomalous capital market conditions that impacted the DCF model inputs, and ignore cost of equity evidence produced by alternative models.[381]

235. MISO TOs argue that, therefore, in establishing the new 9.88% base ROE upon resolution of the First Complaint proceeding, the Commission was acting on its own motion pursuant to its authority under section 313(a) of the FPA[382] to modify Opinion No. 551. They contend that, as a result, the 9.88% base ROE that the Commission established upon resolution of the First Complaint proceeding can be effective only prospectively as of the date of the issuance of Opinion No. 569—November 21, 2019.[383]

236. MISO TOs argue that, if the Commission holds that it did fix a legal error through the adoption of the new methodology for determining a base ROE, the Commission should nonetheless use its discretion not to require the payment of interest on the refunds directed. MISO TOs note that "the Commission is not required to order that interest be paid on all refunds"[384] and contend that the Commission should use its discretion not to include interest with the refunds for the period from September 28, 2016, going forward because the full status quo ante cannot be restored in this case. They assert that this is the case because the Commission has implicitly recognized that some non-public utility members of MISO do not have a refund obligation relating to complaints that were filed prior to 2017,[385] and thus that non-public utility members of MISO may not have an obligation to make refunds for the First Complaint, which was filed in 2013. MISO TOs

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[380] *Id.* at 85-86 (citing Opinion No. 569, 169 FERC ¶ 61,129 at PP 20, 523).

[381] *Id.* at 86.

[382] *Id.* (citing 16 U.S.C. § 825l(a) (2018)).

[383] *Id.* at 86-87.

[384] *Id.* at 87 (citing *Trunkline Gas Co.*, 69 FERC ¶ 61,047, at 61,183 (1994) (citing *Estate of French v. FERC*, 603 F.2d 1158, at 1167–68 (5th Cir. 1979))).

[385] *Id.* at 88-89 (citing *Midcontinent Indep. Sys. Operator, Inc.*, 151 FERC ¶ 61,050, at P 24 (2015) (only as of the effective date of their RTO adder are non-public utilities obligated to make refunds for Docket Nos. EL14-12 and EL15-45)).

argue that, without all transmission-owning members of MISO contributing their share of refunds, it will be impossible to reinstitute the full status quo ante.[386]

237. Ameren similarly argues that the 9.88% base ROE that the Commission found to be a new just and reasonable base ROE in the First Complaint proceeding cannot be made effective as of the date of Opinion No. 551, and thus no refunds can be directed for the period from September 28, 2016 to November 21, 2019. Ameren contends that section 206 of the FPA only permits the Commission to make a new just and reasonable rate effective prospectively and that, therefore, the Commission acted beyond its authority in making the 9.88% base ROE established in Opinion No. 569 effective as of the date of Opinion No. 551.[387]

238. Ameren asserts that the D.C. Circuit's decision in *City of Anaheim v. FERC* also prohibits the Commission from requiring refunds for the period from September 28, 2016 to November 21, 2019, based on its finding in the First Complaint proceeding that 9.88% is a new just and reasonable base ROE. Ameren contends that, in that case the Commission granted a complaint, but stated that it would set a just and reasonable rate in the future, and the court found that the Commission could not make the rate that it set in the future effective retroactively. Ameren argues that there is no meaningful difference between postponing the fixing of a new rate as the Commission did in *City of Anaheim* and modifying Opinion No. 551 and replacing the rate fixed there with another one calculated by a different method, as the Commission did in Opinion No. 569. Ameren contends that the act of fixing a new rate undersection 206 cannot be a three-year process because that would impermissibly expand the Commission's refund authority.[388]

239. Ameren argues that the legal error doctrine does not give the Commission authority to direct refunds for the period from September 28, 2016, to November 21, 2019, as a result of its decision in the First Complaint proceeding. Ameren asserts that, unlike the *ISO New England Inc. v. Bangor Hydro-Electric Co.*[389] case that the Commission cites in Opinion No. 569, a court has not vacated any of the Commission decisions in these proceedings and therefore the legal error doctrine does not apply in these proceedings. Ameren acknowledges that the Commission is empowered to change

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[386] *Id.* at 89.

[387] Ameren Rehearing Request at 13-20.

[388] *Id.* at 17-19.

[389] 161 FERC ¶ 61,031 (2017).

its order on rehearing, but argues that, when doing so, it can only fix a new rate that is "thereafter observed."[390]

240. Transource Energy argues that the Commission can only make the rate that it adopts for the First Complaint proceeding effective prospectively, and not effective as of the date of Opinion No. 551.[391] Transource Energy asserts that, if the Commission believes it has the discretion to make the rate adopted upon resolution of the First Complaint proceeding effective as of the date of Opinion No. 551, it should find that the 10.32% ROE ordered in Opinion No. 551 is just and reasonable. Transource Energy further contends that under the Commission's methodology adopted in Opinion No. 569, there is no evidence showing that a 10.32% ROE is not just and reasonable. Transource Energy notes that the 10.32% base ROE adopted in Opinion No. 551 falls within the quartile range of presumptively just and reasonable ROEs for the period at issue in Opinion No. 551, which is 9.29% to 10.47%. Transource Energy further contends that the Commission's decision in Opinion No. 569 represents a change in policy and not a correction of a legal error. In addition, Transource Energy argues that the Commission should use its discretion to not order additional refunds for the First Complaint proceeding's 15-month refund period because customers benefitted from investments during the refund period.[392]

2. Commission Determination

241. We deny the requests for rehearing of the Commission's decision in Opinion No. 569 to order refunds for the period from September 28, 2016, to November 21, 2019, based on its decision in the First Complaint proceeding. In Opinion No. 569, the Commission granted rehearing of the Commission's decision in Opinion No. 551 that, in the First Complaint proceeding, a 10.32% base ROE was a just and reasonable new ROE under the second prong of section 206, instead finding that a 9.88% base ROE was a just and reasonable new ROE. Accordingly, the Commission's decision in Opinion No. 569 granted rehearing of the decision in Opinion No. 551 to make 10.32% the new base ROE effective prospectively from the date of Opinion No. 551. Consequently, the new ROE that the Commission set in Opinion No. 569 in granting rehearing, and which is modified in this order, is effective as of the date of the original decision which is being modified on rehearing (i.e., the date of Opinion No. 551).

242. As the Commission has explained, "[R]ate changes required in section 206 proceedings should take effect as of the date of the order setting rates, *not* the date of the

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[390] Ameren Rehearing Request at 20-23.

[391] Transource Energy Rehearing Request at 36-38.

[392] *Id.*

rehearing—regardless of whether and to what extent the rehearing order changes the rates originally allowed."[393] The Commission further explained that "[s]uch a policy is fair to both utilities and ratepayers since it allows finally determined just and reasonable rates to go into effect at the earliest possible date, thereby preventing unjust enrichment of one party for any period of time. It also eliminates any incentive parties would have to delay the effective date of new rates."[394] Accordingly, the Commission's decision to grant rehearing of Opinion No. 551 to modify the rate established in that order for the First Complaint proceeding under section 206 takes effect as of the date of the order setting that rate (i.e., Opinion No. 551), not as of the date of Opinion No. 569 or this order. As discussed further below, because the changed rate set on rehearing of Opinion No. 551 is effective as of the date of that order, it is appropriate to direct refunds for the period from that date through the date of this order, which establishes the finally determined just and reasonable rate.

243. We disagree with MISO TOs' argument that this is not a case where the Commission fixed an error on rehearing of Opinion No. 551, and with Ameren's and Transource Energy's arguments that the new replacement base ROE established in granting rehearing of Opinion No. 551 can only be effective prospectively from the date of Opinion No. 569. MISO TOs contend that, while the Commission granted rehearing of Opinion No. 551 in part, it is unclear as to which issue presented on rehearing the Commission granted because none of the rehearing requests asked the Commission to adopt a new ROE methodology.[395] MISO TOs, instead, contend that opposing parties requested rehearing on the grounds that the composition of the DCF proxy group was incorrect, and that Commission should consider only DCF results, ignore the anomalous capital market conditions that impacted the DCF model inputs, and ignore cost of equity evidence produced by alternative models.[396] While it may be true that a party did not explicitly request that the Commission reach each and every exact decision that it made in Opinion No. 569, the Commission nonetheless acted within its discretion to reach its conclusions and these conclusions involved granting rehearing of the Commission's decision in Opinion No. 551 to establish a 10.32% base ROE as the new ROE under the second prong of section 206 in the First Complaint proceeding.

244. In Opinion No. 551, the Commission relied on the DCF analysis and looked to the CAPM, Risk Premium, and Expected Earnings models as corroborative evidence to support its decision. On rehearing, certain parties argued, as MISO TOs note, that the

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[393] *Ariz. Pub. Serv. Co.*, 26 FERC ¶ 61,087, at 61,221 (1984).

[394] *Id.*

[395] MISO TOs Rehearing Request at 85-86.

[396] *Id.* at 86.

Commission should have considered only DCF results and ignored those alternative models.[397] In Opinion No. 569, as modified in this order, the Commission granted rehearing to reach a logical middle ground that does not consider only DCF, as those parties requested, but does depart from Opinion No. 551 by considering only some of the other three models that the Commission initially considered in Opinion No. 551. Specifically, here we consider the CAPM and Risk Premium models in addition to the DCF model, but not the Expected Earnings model, which the Commission initially did consider in Opinion No. 551. In reaching its decision on rehearing of Opinion No. 551, the Commission is not limited to only reaching a conclusion that replicated every detail of a conclusion that a party had explicitly proposed.[398] In relevant part, the Commission, upon a party's application for rehearing, "shall have power to grant or deny rehearing or to abrogate or modify its order without further hearing."[399] Accordingly, the Commission may modify its order on rehearing as it has here, because there exists no such limitation as a requirement that the Commission may only modify its order if the exact modification is explicitly proposed by a party on rehearing. The Commission found merit in some of the arguments against considering all of the non-DCF models but was not persuaded to ignore all of the models. Accordingly, it reached a conclusion arising from compromise that considered some, but not all, of the alternative models that were considered in Opinion No. 551. As a result of partially granting rehearing on these issues, the Commission granted rehearing of its decision to establish 10.32% as a new replacement base ROE in the First Complaint proceeding. Accordingly, this is a case where the Commission granted rehearing to modify Opinion No. 551, and that modified conclusion is effective as of the date of Opinion No. 551.

245. While the Commission's grant of rehearing of Opinion No. 551 is sufficient to justify the Commission's ordering of refunds from the date of Opinion No. 551—September 28, 2016—through the date of this order, the Commission's decision to order such refunds is further justified by the fact that it is correcting a legal error in granting rehearing to change the new just and reasonable ROE established for the First Complaint proceeding in Opinion No. 551. Although Ameren is correct that none of the Commission decisions in these proceedings have been vacated by a court, that does not mean that there was no legal error in the Commission's decisions in these proceedings. In *Emera Maine*, the D.C. Circuit found that the Commission failed to satisfy its dual burden under section 206 of the FPA by finding that the result of a single ROE analysis was sufficient to demonstrate that an existing base ROE was unjust and unreasonable if it exceeded that result and that such result was a just and reasonable

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[397] *See id.* at 86.

[398] *See* 16 U.S.C. § 825*l*.

[399] *Id.*

replacement ROE. Opinion No. 551 and Initial Decision (II) in the Second Complaint proceeding both used the same reasoning that the D.C. Circuit found was insufficient to satisfy the Commission's burden under section 206. Accordingly, while no court has vacated a specific decision in this case, the rationale on which Opinion No. 551 and Initial Decision (II) in the Second Complaint proceeding are based has been rejected by the D.C. Circuit as in violation of section 206. As a result, those Commission decisions are based on a legal error identified by the D.C. Circuit. The fact that the court did not explicitly identify that legal error in a case involving a decision in these proceedings does not mean that there is no error in Opinion No. 551 and Initial Decision (II). To find otherwise would allow the Commission to continue to make decisions that are based on reasoning that has been found to be unlawful and only require the Commission to correct those decisions when a court has repeated its previous conclusion in every individual applicable case.

246. MISO TOs and Transource Energy also argue that the legal error doctrine does not apply here because the methodology adopted in Opinion No. 569 goes beyond what they contend is necessary to fix the problems identified by the *Emera Maine* court, and therefore represents a change in policy and not correction of a legal error. We disagree. The court in *Emera Maine* found that the Commission acted arbitrarily and outside of its statutory authority because its single ROE analysis failed to include an actual finding as to the lawfulness of the existing base ROE at issue. The court remanded the proceeding for the Commission to make that actual finding, but it did not specify exactly how the Commission needed to make that finding. In Opinion No. 569, as modified herein, the Commission concluded that the best way to make that finding in these proceedings in light of its statutory obligations was to revise its methodology for analyzing base ROEs under section 206 as explained herein. Accordingly, while MISO TOs and Transource Energy would prefer the Commission to arrive at this finding in a different way, that does not mean that the Commission's action is a change in policy instead of a correction of a legal error.

247. We are also not persuaded by arguments that the Commission should exercise its discretion to not order interest on the refunds for the period from the date of Opinion No. 551 through the date of this order replacing the base ROE set in in Opinion No. 551. While MISO TOs are correct that the Commission is not required to order that interest be paid on all refunds, we find that there are no equitable reasons that would warrant not ordering interest on the refunds ordered from the date of Opinion No. 551 through the date of this order. The parties to the First Complaint proceeding had notice that the base ROE established to be prospective from the date of Opinion No. 551 was subject to rehearing and therefore could be modified such that the modified rate would result in refunds, with interest pursuant to the Commission's authority under section 206. We are also not persuaded by MISO TOs' argument that the Commission should exercise its discretion to not require interest on the refunds because the status quo ante cannot be

fully restored since a separate Commission order "implicitly has recognized"[400] that some non-public utility members of MISO do not have a refund obligation relating to complaints that were filed prior to 2017.[401] As the precedent cited by MISO TOs provides, the Commission is not restricted to only requiring interest on refunds when it can completely restore the status quo ante, but rather, whether the status quo ante can be fully restored is merely a consideration that "may . . . offset . . . at least in part"[402] a full refund. MISO TOs also correctly recognize that "whether to order interest in crafting a remedy is a matter of Commission discretion."[403] MISO TOs have not persuaded us that the fact that some members of MISO may have different obligations with respect to the subject refunds is sufficient to use to our discretion to deny the complainants a full refund with interest. The payment of interest on refunds merely "ensures that the amounts to be refunded are, in fact, refunded through the addition of interest so that the recipient receives payment in inflation-adjusted dollars . . . to make the recipients whole,"[404] consistent with the Commission's "general policy of granting full refunds" for overcharges.'"[405] While we may exercise our discretion to decline to make recipients whole through the payment of interest on refunds, MISO TOs' argument on this point is not a sufficient reason to do so. On balance, we find that is more appropriate to ensure that the overcharged entities are made whole through the payment of interest on refunds than it is to decline to require interest because some members of MISO may have different obligations with respect to the subject refunds such that the refunds paid do not exactly reconstitute the status quo ante.

248. Transource Energy argues that the Commission should use its discretion to not order additional refunds for the First Complaint proceeding's 15-month refund period because customers benefitted from investments during the refund period.[406] We find that this argument is similarly unavailing. Transmission owners are constantly making new

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[400] MISO TOs Rehearing Request at 89.

[401] *Id.* at 88-89 (citing *Midcontinent Indep. Sys. Operator, Inc.*, 151 FERC ¶ 61,050 at P 24).

[402] *Panhandle E. Pipe Line Co.*, 69 FERC ¶ 61,048, at 61,189 (1994) (quoting *Consumer Fed'n of America v. FPC*, 515 F.2d 347, 359 (D.C. Cir. 1975)).

[403] MISO TOs Rehearing Request at 87 (quoting *Transcon. Gas Pipe Line Corp.*, 71 FERC ¶ 61,108, at 61,361 (1995)).

[404] *La. Pub. Serv. Comm'n*, 153 FERC ¶ 61,033, at P 14 (2015).

[405] *Consolidated Edison Co. of N.Y. v. FERC*, 347 F.3d 964, 972 (D.C. Cir. 2003).

[406] Transource Energy Rehearing Request at 38.

investments and changing investments during proceedings that may result in refund obligations. Therefore, to find that the existence of these investments alone would absolve such transmission owners from ordering refunds resulting from a Commission decision would mean that transmission owners would only owe refunds in the rarest of circumstances. We find that this would be contrary to the purpose of the refund obligation in section 206.

249. Consequently, we deny rehearing on this issue and find that, by granting rehearing of the decision in Opinion No. 551 to establish a new just and reasonable base ROE, and by acting to correct a legal error, it is appropriate to direct refunds, with interest, for the period from the effective date of the just and reasonable base ROE that was set in Opinion No. 551 which is being replaced in this order— September 28, 2016—through the date of this order, based on the new 10.02% base ROE established for the First Complaint proceeding in this order.

C. Second Complaint Proceeding Refunds

1. Rehearing Requests

250. CAPs argue that the Commission erred in not requiring refunds for the Second Complaint proceeding's refund period. They contend that the First Complaint and Second Complaint each challenged the base ROE in effect as of the date of filing of each complaint and had separate refund periods.[407] CAPs assert that, therefore, the mere fact that the two separate refund periods exceed 15 months does not mean that section 206 of the FPA is violated, "particularly in view of the fact that Commission orders set both refund periods, and the Commission itself acknowledged that the ROE in force when each complaint was filed was demonstrated to be unjust and unreasonable based on evidence of market conditions during the relevant study period."[408]

251. CAPs further contend that the Commission's interpretation of the existing rate to be analyzed in the Second Complaint proceeding creates a loophole that utilities could exploit to vitiate the consumer protection intended by section 206. In particular, CAPs assert that a utility could make a tactical section 205 filing after a section 206 filing is signaled or underway to undermine section 206's refund and prospective relief remedies. CAPs argue that, for example, if an initial decision identifies a new just and reasonable base ROE resulting from a section 206 complaint, the subject utility could make a section 205 filing before issuance of a Commission order on the initial decision that reduces its base ROE to a level well above the base ROE the initial decision determined was just and reasonable, but just within the top end of what the initial decision identifies

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[407] CAPs Rehearing Request at 52-53.

[408] *Id.* at 53.

as the zone of presumptively just and reasonable ROEs, such that the utility's proposed base ROE in the section 205 filing would likely be accepted by the Commission. CAPs argue that, under the Commission's rationale in Opinion No. 569, in such a case, the base ROE in the utility's section 205 filing would become the currently effective base ROE that the Commission would examine for purposes of acting on the initial decision, meaning that this base ROE would likely not be found unjust and unreasonable in the Commission's order on the initial decision because it falls within the zone of presumptively just and reasonable ROEs identified in the initial decision. CAPs contend that, in such a case, the utility would have successfully shielded itself both from refunds and from a prospective reduction down to the cost-based level found in the initial decision. CAPs argue that, because of this possibility, the Commission should reconsider its finding that the FPA requires section 206 relief to be denied if the rate in effect just before a final order applying section 206 is just and reasonable, or at least clarify how it would prevent such tactics from vitiating relief under section 206.[409]

252. CAPs further contend that, even if the Commission does not reverse its determination that the outcome of the Second Complaint was dependent on the outcome of the First Complaint, it still has and should exercise discretion to order refunds for the Second Complaint proceeding. CAPs assert that, because section 206 contains no deadline for the Commission to act on a complaint, where two complaints raising overlapping issues are pending before the Commission simultaneously, the order in which the Commission acts on the complaints is within the Commission's discretion. CAPs argue that the Commission should have acted on the Second Complaint before acting on rehearing of Opinion No. 551 because this would have kept prospective rates, which can affect future conduct, aligned with the most recent and accurate evidence of the MISO TOs' cost of equity. CAPs contend that, by acting in this sequence, MISO transmission customers would have been entitled to refunds for the Second Complaint proceeding's refund period and the First Complaint proceeding's refund period because the ROE set by an order in the Second Complaint could not be deemed to be the "existing" ROE for purposes of deciding the First Complaint. CAPs assert that, therefore, the Commission's rationale for denying refunds in the Second Complaint proceeding effectively claims that the Commission's procedural decisions can expand or contract the statutory rights of public utility customers.[410]

253. LPSC argues that Opinion No. 569 interprets section 206 to mean that the Commission must decide whether the rate that is "currently effective" at the time it issues its opinion is just and reasonable, as opposed to the rate that was in effect at the time the

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[409] *Id.* at 53-54.

[410] *Id.* at 56-59.

complaint was filed and contends that this interpretation violates the FPA.[411] LPSC contends that section 206 provides that the Commission shall determine the just and reasonable rate, if the Commission determines that the rate "demanded, observed, charged, or collected by any public utility . . . is unjust, unreasonable, unduly discriminatory or preferential."[412] LPSC asserts that Opinion No. 569 is inconsistent with this plain language because it requires an analysis of whether a new rate that had never been charged or collected by the utility is just and reasonable. LPSC contends that the MISO TOs have never "demanded, observed, charged, or collected" the 9.88% ROE that was established in Opinion No. 569 from their customers, so the FPA could not have intended for that to be the rate analyzed by the Commission.[413]

254. LPSC argues that the Commission's interpretation of the existing rate to be analyzed in the Second Complaint proceeding would prevent the Commission from ever granting refunds in a second ROE proceeding, even if the Commission found that the newly effective ROE that resulted from the first ROE proceeding had become unjust and unreasonable by the time the second complaint was filed. LPSC contends that this is the case because section 206 provides for refunds to "persons who have paid those rates" but no person would have paid the rate established in such a first complaint proceeding.[414]

255. LPSC also contends that the Commission's interpretation on this point is inconsistent with the Commission's precedent in *Golden Spread Elec. Coop., Inc. v. Southwestern Pub. Serv. Co.*[415] LPSC asserts that, in that case, the Commission rejected a company's argument that a 2013 ROE complaint should be dismissed because it served only to extend the refund effective period associated with a 2012 ROE complaint, and explained that, "In assessing the 2013 Complaint, the relevant comparison is between the current ROE and the ROE sought in the 2013 Complaint."[416]

256. LPSC further argues that Opinion No. 569 is also arbitrary because its conclusions rely entirely on the order that the Commission decides the ROE proceedings, but there is no statute or regulation that requires the Commission to resolve section 206 proceedings

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[411] LPSC Rehearing Request at 17-19.

[412] *Id.* at 19 (citing 16 U.S.C. § 824e (2018)).

[413] *Id.*

[414] *Id.* at 19-20.

[415] 151 FERC ¶ 61,126 (2015).

[416] LPSC Rehearing Request at 21 (citing *Golden Spread Elec. Coop., Inc. v. Southwestern Pub. Serv. Co.*, 151 FERC ¶ 61,126 at P 24).

chronologically. LPSC contends that refunds could have been granted for the second complaint proceeding and a different ROE would have applied prospectively if Opinion No. 569 had resolved the second complaint proceeding first. LPSC asserts that Congress did not intend to give the Commission the power to decide the justness and reasonableness of rates and whether refunds should be granted based on the order that it chooses to decide complaints.[417]

257. In addition, LPSC argues that Opinion No. 569 is inconsistent with the Commission's precedent that a second ROE complaint can be filed and a second refund effective period can be ordered, as long as the second complaint is based on new analyses and data. LPSC contends that, "Contrary to its precedent, Opinion No. 569 now finds that determining whether the ROE in a second ROE complaint proceeding is unjust and unreasonable by analyzing the ROE that was in effect when the complaint was filed would effectively extend the statutory fifteen-month refund effective period."[418] LPSC argues that, in *Firstenergy Service Co. v. FERC*, 758 F.3d 346 (D.C. Cir. 2014), the D.C. Circuit stated that "FERC is required to evaluate a 206 complaint as to existing rates specifically because they might have become unjust and unreasonable by intervening shifts in circumstances"[419] and that the Commission should do the same here and rule that the rate in effect at the time the Second Complaint was filed should be analyzed to assess possible "intervening shifts in circumstances."[420]

258. RPGI similarly argues that the Commission's interpretation of section 206 to not permit refunds for the Second Complaint proceeding is unsupported. RPGI asserts that the Commission's interpretation sets up a scenario in which the ROE in force on a second complaint's date of filing becomes virtually irrelevant. RPGI contends that a complainant would know that, if it filed, the benchmark against which its case would be evaluated would not be the ROE in effect on the date the second complaint would be filed—which is known—but rather the ROE set by the first proceeding and where it falls in the second proceeding's updated zone of reasonableness, neither of which is known at the second proceeding's outset. RPGI asserts that, thus, after Opinion No. 569, filing a second complaint upon the expiration of a first complaint's refund period represents such

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[417] *Id.* at 21-23.

[418] *Id.* at 24.

[419] *Id.* at 27-28 (citing *Firstenergy Service Co. v. FERC*, 758 F.3d at 356).

[420] *Id.*

a high risk of a “no-change” outcome as to effectively bar successive complaints, even if the data from the second proceeding supports an ROE lower than that set by the first.[421]

259. RPGI argues that, if the Commission’s concern is that successive complaints require it to make duplicative findings of one ROE’s unlawfulness, then it could consolidate proceedings. RPGI further contends that, if the Commission’s concern is the effect of successive refund periods on the MISO TOs, the appropriate course of action is seeking a statutory change, not adopting a strained statutory interpretation.[422]

2. <u>Commission Determination</u>

260. We deny rehearing on this issue. We continue to find, as the Commission did in Opinion No. 569, that, for purposes of deciding whether a rate charged by a public utility is unjust and unreasonable and determining a new just and reasonable rate “to be thereafter observed” pursuant to section 206(a) of the FPA, we must assess whether the public utility’s currently effective rate is unjust and unreasonable, not some earlier rate that may have been in effect when the complaint was filed but has now been superseded. As explained in Opinion No. 569, in the context of successive, or pancaked, complaints like those in these proceedings, if the Commission’s analysis in the successive complaint analyzed some earlier rate that may have been in effect when the complaint was filed but has since been superseded, it would permit the Commission to order refunds for a period beyond the 15-month statutory refund period based on a single decision in the preceding complaint decision. We find that this would allow the Commission to use a single decision as the predicate for issuing refunds beyond the refund period applicable to that decision, which would exceed the refund authority granted to the Commission in section 206.

261. CAPs argue that the First Complaint and Second Complaint each challenged the base ROE in effect as of the date of filing of each complaint and had separate refund periods, and the mere fact that the two separate refund periods exceed 15 months does not mean that section 206 is violated. CAPs misinterpret the Commission’s finding in Opinion No. 569. In Opinion No. 569, the Commission did not find that the mere fact that the First Complaint and Second Complaint proceedings had separate refund periods that combined exceed 15 months rendered the Commission unable to issue refunds in the Second Complaint proceeding. It would have been possible for the Commission to order refunds for the refund periods in both complaint proceedings if the base ROE resulting from resolution of the First Complaint proceeding was no longer just and reasonable based on the facts and circumstances of the Second Complaint proceeding. However, complainants did not show that the existing rate reviewed in the Second Complaint

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[421] RPGI Rehearing Request at 17-21.

[422] *Id.* at 22-23.

proceeding was unjust and unreasonable under the facts and circumstances of that proceeding.

262. Both complaints challenged the MISO TOs' base ROE, and the Commission established a new just and reasonable base ROE in the First Complaint proceeding that was filed first chronologically. As discussed above, the Commission found that it was required to review that new base ROE as the existing rate for purposes of the Second Complaint and complainants did not show that this existing rate was unjust and unreasonable. The Commission then found that section 206 provides that refunds may be ordered in a complaint proceeding only when the Commission grants prospective relief in that proceeding because section 206 only permits refunds in proceedings where the Commission sets a new rate to be "thereafter observed and in force."[423] As a result, the Commission found that it did not have authority under section 206 to order refunds in the Second Complaint proceeding because it did not grant prospective relief by establishing a new base ROE in that proceeding. The Commission further explained that ordering refunds in the Second Complaint proceeding even though it did not grant prospective relief in that proceeding would in fact allow its determination in the First Complaint proceeding to serve as the predicate for two 15-month refund periods, which is beyond the Commission's authority in section 206. Accordingly, the fact that the First Complaint and Second Complaint proceedings had separate refund periods that together exceeded 15 months did not render the Commission unable to issue refunds in the Second Complaint proceeding. Rather, it was the fact that the Commission could not grant prospective relief in the Second Complaint proceeding because the complainants did not show that the rate that was reviewed in that Second Complaint proceeding was unjust and unreasonable. Had the complainants made that showing, the Commission could have ordered refunds in the Second Complaint proceeding, regardless of the fact that the refund periods in the First Complaint proceeding and Second Complaint proceeding add up to more than 15 months. However, that was not the case and consequently we find CAPs' argument on this point unavailing.

263. CAPs argue that the Commission's interpretation of the existing rate to be analyzed in the Second Complaint proceeding creates a loophole pursuant to which a utility could make a tactical section 205 filing after a section 206 filing is signaled or underway to undermine section 206's refund and prospective relief remedies. CAPs assert that such a filing could, for example, propose to reduce the utility's base ROE to a level well above the base ROE the initial decision determined was just and reasonable, but just within the top end of what the initial decision identifies as the zone of presumptively just and reasonable ROEs, such that the utility's proposed base ROE in the section 205 filing would likely be accepted by the Commission and then become the currently effective base ROE that the Commission would examine for purposes of acting

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[423] Opinion No. 569, 169 FERC ¶ 61,129 at P 568.

on the initial decision. This argument does not persuade us that our interpretation is inappropriate. As an initial matter, we note that the presumptively just and reasonable ranges applied in this order are limited to our analysis of complaints filed under section 206. There is no section 205 filing before us in this proceeding and we are not making any determinations regarding whether or how the presumptively just and reasonable ranges used in this order would apply in the context of a section 205 filing. Moreover, if a utility were to make such a tactical section 205 filing proposing a new base ROE while a section 206 proceeding challenging the utility's base ROE is still pending a final Commission decision, then the Commission could consider such a section 205 filing in light of the pending section 206 proceeding. "The Commission has broad discretion to structure its proceedings so as to resolve a controversy in the way it best sees fit,"[424] and, in addressing such a section 205 filing, the Commission could consider the common issues that would likely be raised by a section 205 filing to change the same base ROE that is being challenged in a pending section 206 proceeding. For example, in analogous circumstances, the Commission consolidated a rate filing pursuant to section 4 of the Natural Gas Act (NGA) with an ongoing complaint proceeding pursuant to section 5 of the NGA involving the same rates. There the Commission noted that "KCC asserts that Southwest Gas's instant section 4 rate filing is nothing more than an attempt to circumvent the ongoing section 5 complaint proceeding"[425] and found that "the section 4 filing appears as an outgrowth of the section 5 complaint proceeding"[426] for which consolidation would "provide the most efficient and effective forum to handle issues common to both proceedings."[427] Any section 205 filing like the type suggested by CAPs would be considered by the Commission in light of any other proceedings

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[424] *PJM Transmission Owners*, 120 FERC ¶ 61,013, at P 12 (2007). *See also Ameren Energy Generating Co.,* 108 FERC ¶ 61,081, at P 23 (2004) ("The courts have repeatedly recognized that the Commission has broad discretion in managing its proceedings.); *Fla. Mun. Power Agency v. FERC*, 315 F.3d 362, 366 (D.C. Cir. 2003) (citing *Telecomm. Resellers Assoc. v. FCC*, 141 F.3d 1193, 1196 (D.C. Cir. 1998) (stating that administrative agencies enjoy broad discretion to manage their own dockets); *FPC v. Transcontinental Gas Pipe Line Corp.*, 423 U.S. 326, 333 (1976) (stating that agencies can determine how best proceed to develop the needed evidence); *Richmond Power & Light v. FERC*, 574 F.2d 610, 624 (D.C. Cir. 1978) (stating that agencies have wide leeway in controlling their calendars)).

[425] *Panhandle Complainants v. Sw. Gas Storage Co.*, 120 FERC ¶ 61,207, at P 19 (2007).

[426] *Id.* P 20.

[427] *Id.* P 21.

involving common issues, including section 206 proceedings.[428] We do not believe that the Commission's interpretation of the existing rate to be analyzed in the Second Complaint proceeding would somehow allow utilities to make section 205 filings that would dictate or otherwise limit the Commission's ability to appropriately determine just and reasonable rates in section 206 proceedings.

264. LPSC argues that Opinion No. 569's decision to not order refunds in the Second Complaint proceeding is inconsistent with section 206 because section 206 requires the Commission to determine whether a rate "demanded, observed, charged, or collected by any public utility . . . is unjust, unreasonable, unduly discriminatory or preferential"[429] but MISO TOs have never "demanded, observed, charged, or collected" the base ROE that was established in the First Complaint proceeding from their customers, but that is the rate that the Commission analyzed in making its determination in the Second Complaint proceeding. We find this argument unavailing. While at the time the Second Complaint was filed, the new just and reasonable rate established in the First Complaint proceeding had not yet been demanded, observed, charged or collected, the Commission's decision in the First Complaint proceeding made the new base ROE established in that proceeding the rate that was demanded, observed, charged and collected for the First Complaint proceeding's refund period. Therefore, when the Commission analyzed the new just and reasonable rate established in the First Complaint proceeding in making its determination in the Second Complaint proceeding, that rate was the one demanded, observed, charged and collected for the First Complaint proceeding's refund period, which is consistent with the language of section 206. The fact that the Commission acted on the successive complaints in the First Complaint and Second Complaint proceedings in a single order instead of in two separate sequential ones does not render the new base ROE established in the First Complaint proceeding a fiction that is not actually applied by the MISO TOs. Rather, the Commission's decision in the First Complaint proceeding made the rate established there the rate "demanded, observed, charged, or collected" for purposes of the First Complaint proceeding and the Commission then reviewed that rate as the existing rate in making its decision on the Second Complaint which followed the First Complaint. We are not persuaded that this analysis is inconsistent with section 206.

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[428] *See, e.g.*, *Mobil Oil Explor. & Prod. SE Inc. v. United Distrib. Cos.*, 498 U.S. 211, 230 (1991) ("An agency enjoys broad discretion in determining how best to handle related, yet discrete, issues in terms of procedures."); *Nadar v. FCC*, 520 F.2d 182, 195 (D.C. Cir. 1975) ("[T]his court has upheld in the strongest terms the discretion of regulatory agencies to control the disposition of their caseload.").

[429] LPSC Rehearing Request at 19 (citing 16 U.S.C. § 824e).

265. CAPs and LPSC argue that the Commission is not required to act on the First Complaint proceeding first and should have acted on the Second Complaint proceeding first. They contend that there is no requirement that the Commission resolve section 206 proceedings chronologically. As an initial matter, we note that, "The Commission has broad discretion to structure its proceedings so as to resolve a controversy in the way it best sees fit."[430] The Commission "is generally master of its own calendar and procedures."[431] In these proceedings, we find that it is appropriate to act on the First Complaint proceeding first and then the Second Complaint proceeding. The Commission permitted the Second Complaint because it was "was based on financial data from a different time period, and produced a different proxy group, than the DCF analysis set forth in the [First Complaint]."[432] In that order, the Commission explained that it "has allowed multiple complaints regarding the same ROE, where the subsequent complaints are based on 'new, more current data.'"[433] Accordingly, the premise for permitting the Second Complaint was that it was based on different, more current data, than the data in the First Complaint proceeding. We find that it is appropriate to address the First Complaint first because the Commission must first determine what the final data and results from the First Complaint are before determining whether the Second Complaint can be granted based on how the Second Complaint's data have changed as compared to the data in the First Complaint. Moreover, we find that it would not be appropriate to follow the approach suggested by CAPs and LPSC because it could force the Commission to delay action on a preceding complaint that is likely closer to resolution until it has first acted on a successive complaint because that successive complaint is

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[430] *PJM Transmission Owners*, 120 FERC ¶ 61,013 at P 12.

[431] *Stowers Oil and Gas Co.*, 27 FERC ¶ 61,001 (1984); *see also Ameren Energy Generating Co.,* 108 FERC ¶ 61,081 at P 23 ("The courts have repeatedly recognized that the Commission has broad discretion in managing its proceedings.); *Fla. Mun. Power Agency v. FERC*, 315 F.3d 362, 366 (D.C. Cir. 2003) (citing *Telecomm. Resellers Assoc. v. FCC*, 141 F.3d 1193, 1196 (D.C. Cir. 1998) (stating that administrative agencies enjoy broad discretion to manage their own dockets); *FPC v. Transcontinental Gas Pipe Line Corp.*, 423 U.S. 326, 333 (1976) (stating that agencies can determine how best proceed to develop the needed evidence); *Richmond Power & Light v. FERC*, 574 F.2d 610, 624 (D.C. Cir. 1978) (stating that agencies have wide leeway in controlling their calendars)).

[432] MISO II Rehearing Order, 156 FERC ¶ 61,061 at P 34.

[433] *Id.* P 33 (quoting *Consumer Advocate Div. of the Pub. Serv. Of West Virginia v. Allegheny Generating Co.*, 67 FERC ¶ 61,288, *order on reh'g*, 68 FERC ¶ 61,207, at 61,998 (1994)).

"aligned with the most recent and accurate evidence."[434] This could further delay Commission action on section 206 complaint proceedings that are often already very protracted. In addition, CAPs' and LPSC's approach would not always benefit ratepayers over utilities. For example, it is possible that, in resolving a successive complaint first, ratepayers would be subject a higher rate during such a complaint's refund period than they would have been subject to if the preceding complaint resulted in a prospectively effective rate that overlapped with the successive complaint's refund period which was lower than the rate resulting from the successive complaint. Accordingly, we find that it is appropriate to address the complaints in these proceedings in chronological order by deciding the First Complaint before deciding the Second Complaint.

266. RPGI argues that, if the Commission's concern in deciding to not order refunds in the Second Complaint proceeding was that it would be required to make duplicative findings of one ROE's unlawfulness, then it could consolidate the First Complaint and Second Complaint proceedings. We find this argument unavailing. The Commission has explained that "[i]n general, the Commission consolidates matters only if . . . consolidation will ultimately result in greater administrative efficiency."[435] However, these proceedings have progressed through hearing, initial decision and, in the case of the First Complaint proceeding, Commission decision, separately with separate records. At this point there would be no greater administrative efficiency in consolidating these two proceedings because they are already close to final resolution. Moreover, RPGI does not explain how consolidation would eliminate the need to identify the existing rate to be analyzed in the Second Complaint proceeding and then determine whether refunds could be issued based on the Commission's analysis of that rate under section 206. Thus, RPGI has not explained how consolidation would change the analysis underlying our decision to not order refunds in the Second Complaint proceeding.

267. RPGI also contends that, if the Commission's concern in making its decision in Second Complaint proceeding is the effect of successive refund periods on the MISO TOs, the appropriate course of action is seeking a statutory change, not adopting a strained statutory interpretation. However, here we must determine how to act in these section 206 complaint proceedings and in order to do so we must determine how to interpret and apply section 206 to these proceedings. The issue before us is not whether it would be appropriate or preferable to seek a statutory change. We must apply the statute as it exists to these proceedings. The fact that RPGI would prefer that the Commission adopt a different interpretation does not mean that the Commission had the option of not applying section 206 as it exists to these proceedings. For the reasons discussed in this order, we find that the application of section 206 to the Second

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[434] *See* CAPs Rehearing Request at 59.

[435] *See, e.g.*, *Startrans IO, LLC*, 122 FERC ¶ 61,253, at P 25 (2008).

Complaint proceeding requires us to dismiss the complaint and not order refunds in that proceeding. Accordingly, we find that RPGI's argument on this point does not persuade us to grant rehearing of our decision to not order refunds in the Second Complaint proceeding.

XIX. Conclusion

268. For the reasons discussed above, we grant in part and deny in part the requests for rehearing of Opinion No. 569. In particular, we require the MISO TOs to adopt a 10.02% base ROE effective September 28, 2016, the date Opinion No. 551 initially required the MISO TOs to adopt a 10.32% ROE. As discussed above, we therefore require the MISO TOs to provide refunds based on that 10.02% base ROE, with interest, for the First Complaint proceeding's 15-month refund period from November 12, 2013 through February 11, 2015, and for the period from September 28, 2016 to the date of this order. Further, as discussed above we are denying rehearing of the Commission's dismissal of the Second Complaint in Opinion No. 569 and its finding that no refunds will be ordered in the Second Complaint proceeding.

The Commission orders:

(A) Rehearing of Opinion No. 569 is granted in part and denied in part, as discussed in the body of this order.

(B) MISO TOs' base ROE is set at 10.02% with a total or maximum ROE including incentives not to exceed 12.62%, effective as of September 28, 2016, as discussed in the body of this order.

(C) MISO and MISO TOs are directed to provide refunds, with interest calculated pursuant to 18 C.F.R. § 35.19a (2019), by December 23, 2020, for the 15-month refund period for the First Complaint from November 12, 2013 through February 11, 2015 and for the period from September 28, 2016 to the date of this order, as discussed in the body of this order.

(D) MISO and MISO TOs are directed to file a refund report a detailing the principal amounts plus interest paid to each of their customers by December 23, 2020.

By the Commission. Commissioner Glick is concurring in part and dissenting in part
in a separate statement attached.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

Appendix I: Risk Premium Results

Risk Premium Model Results

Current Equity Risk Premium	MISO I	MISO II
Average Yield Over Study Period	6.10%	6.02%
Baa Utility Bond Yield	4.65%	5.41%
Change in Bond Yield	-1.45%	-0.61%
Risk Premium/Interest Rate Relationship	-0.7006	-0.6866
Adjustment to Average Risk	1.02%	0.42%
Average Risk Premium over Study Period	4.43%	4.46%
Adjusted Risk Premium	**5.45%**	**4.88%**
Implied Cost of Equity		
Baa Utility Bond Yield	4.65%	5.41%
Adjusted Equity Risk Premium	5.45%	4.88%
Risk Premium Cost of Equity	**10.10%**	**10.29%**

Risk Premium Model Inputs

Docket Number	Utility	Type	Date	Base ROE	Baa Bond Yield	Implied Risk Premium
ER05-515	BG&E	Settlement - Uncontested	Feb-06	10.80	6.07	4.73
ER05-515	BG&E	Settlement - Uncontested	Feb-06	11.30	6.07	5.23
ER05-925	Westar	Settlement - Uncontested	Jun-06	10.80	6.36	4.44
ER07-284	SDG&E	Settlement - Uncontested	Feb-07	11.35	6.14	5.21
ER06-787	Idaho Pwr	Settlement - Uncontested	May-07	10.70	6.15	4.55
ER06-1320	Wisconsin Elec. Pwr	Settlement - Uncontested	May-07	11.00	6.15	4.85
ER07-583	Commonwealth Edison	Settlement - Uncontested	Sep-07	11.00	6.41	4.59
ER06-1549	Duquesne	Settlement - Uncontested	Sep-07	10.90	6.41	4.49
ER08-92	VEPCO	Order	Oct-07	10.90	6.43	4.47
ER08-374	Atlantic Path	Order	Nov-07	10.65	6.44	4.21
ER08-413	Startrans IO	Order	Nov-07	10.65	6.44	4.21
ER08-396	Westar	Declaratory order.	Nov-07	10.80	6.44	4.36
ER08-686	Pepco Holdings	Order	Jan-08	11.30	6.41	4.89
ER07-562	Allegheny	Settlement	Feb-08	11.20	6.42	4.78

ER07-1142	Ariz. Pub. Service	Settlement - uncontested	Apr-08	10.75	6.54	4.21
ER08-1207	VEPCO	Order	May-08	10.90	6.62	4.28
ER08-1402	Duqesne	Order	Jun-08	10.90	6.69	4.21
ER08-1423	Pepco Holdings	Order	Jun-08	10.80	6.69	4.11
ER08-1584	Black Hlls	Settlement - Uncontested	Jun-08	10.80	6.69	4.11
ER09-35/36	Tallgrass / Prairie Wind	Commission Order	Jul-08	10.80	6.80	4.00
ER09-249	Public Service Elec. & Gas	Accepted by FERC	Aug-08	11.18	6.86	4.32
ER09-548	ITC Great Plains	Settlement - Uncontested	Sep-08	10.66	6.94	3.72
ER09-75	Pioneer	Order	Sep-08	10.54	6.94	3.60
ER09-187	SoCal Edison	Order on Paper Hearing	Sep-08	10.04	6.94	3.10
ER08-375	SoCal Edison	Order on Paper Hearing	Nov-08	10.55	7.60	2.95
ER09-745	Baltimore Gas & Elec.	Accepted by FERC	Dec-08	11.30	7.80	3.50
ER07-1069	AEP - SPP Zone	Settlement - Uncontested	Jan-09	10.70	7.95	2.75
ER09-681	Green Power Express	Commission Order	Jan-09	10.78	7.95	2.83
ER08-281	Oklahoma Gas & Elec.	Settlement - Uncontested	Apr-09	10.60	8.13	2.47
ER08-1457	PPL Elec. Utilities Corp.	Settlement - Uncontested	Apr-09	11.00	8.13	2.87

ER08-1457	PPL Elec. Utilities Corp.	Settlement - Uncontested	Apr-09	11.14	8.13	3.01
ER08-1588	Kentucky Utilities Co.	Settlement - Uncontested	Apr-09	11.00	8.13	2.87
ER08-552	Niagara Mohawk	Settlement - Uncontested	Jul-09	11.00	7.62	3.38
ER09-628	National Grid Generation LLC	Settlement - Uncontested	Aug-09	10.75	7.39	3.36
ER08-313	Southwestern Public Service Co.	Settlement - Uncontested	Aug-09	10.77	7.39	3.38
ER10-160	SoCal Edison	Order on Paper Hearing	Sep-09	10.33	7.08	3.25
ER08-1329	AEP - PJM Zone	Settlement - Uncontested	Mar-10	10.99	6.20	4.79
ER10-230	Kansas City Power & Light Co.	Settlement - Uncontested	Aug-10	10.60	6.05	4.56
ER10-355	AEP Transcos - PJM	Settlement - Contested	Aug-10	10.99	6.05	4.95
ER10-355	AEP Transcos - SPP	Settlement - Contested	Aug-10	10.70	6.05	4.66
ER11-1952	SoCal Edison	Order	Sep-10	10.30	5.93	4.37
EL11-13	Atlantic Grid Operations	Declaratory Order	Oct-10	10.09	5.84	4.26
ER11-2895	Duke Energy Carolinas	Settlement - Initial Filing	Oct-10	10.20	5.84	4.37
ER11-2377	Northern Pass Tx	Order	Nov-10	10.40	5.79	4.62
ER12-2300	PSCo	Order	Nov-10	10.25	5.79	4.47

ER10-1377	Northern States Power Co. (MN)	Settlement - Uncontested	Mar-11	10.40	5.94	4.46
ER10-992	Northern States Power Co.	Settlement - Uncontested	Apr-11	10.20	6.00	4.20
ER10-516	South Carolina Electric and Gas	Settlement - Uncontested	Apr-11	10.55	6.00	4.55
ER11-4069	RITELine	Order	May-11	9.93	5.98	3.95
ER12-296	PSEG	Order	Aug-11	11.18	5.71	5.47
ER08-386	PATH	Settlement - uncontested	Sep-11	10.40	5.57	4.83
ER11-2560	Entergy Arkansas, Inc.	Settlement - Uncontested	Dec-11	10.20	5.21	4.99
ER11-2853	PSCo	Settlement - Uncontested	Mar-12	10.10	5.08	5.03
ER11-2853	PSCo	Settlement - Uncontested	Mar-12	10.40	5.08	5.33
ER12-1378	Cleco	Settlement - Uncontested	Nov-12	10.50	4.74	5.77
ER12-2554	Transource Missouri	Settlement - Uncontested	Jan-13	9.80	4.65	5.16
ER12-778	Puget Sound Energy	Settlement - Uncontested	Jan-13	9.80	4.65	5.16
ER12-778	Puget Sound Energy	Settlement - Uncontested	Jan-13	10.30	4.65	5.66
ER11-3643	PacifiCorp Inc.	Settlement - Uncontested	Feb-13	9.80	4.62	5.18
ER12-1650	Maine Public Service Co.	Settlement - Uncontested	Feb-13	9.75	4.62	5.13

ER11-3697	SoCal Edison	Settlement - Uncontested	Jul-13	9.30	4.82	4.49
ER13-941	San Diego Gas and Electric	Settlement - Uncontested	Jan-14	9.55	5.22	4.33
ER12-1589	PSCo	Settlement	Aug-14	9.72	4.76	4.96
ER12-91	Duke Energy Ohio	Settlement - Uncontested	Sep-14	10.88	4.73	6.15
EL12-101	Niagara Mohawk	Settlement - Uncontested	Jan-15	9.80	4.66	5.14
ER13-685	Public Service Company New Mexico	Settlement - Uncontested	Feb-15	10.00	4.62	5.38
ER14-1661	MidAmerican Central California	Settlement - Uncontested	Mar-15	9.80	4.58	5.22
ER15-303	American Transmission Systems, Inc.	Settlement - Uncontested	May-15	9.88	4.58	5.30
ER15-303	American Transmission Systems, Inc.	Settlement - Uncontested	May-15	10.56	4.58	5.98
EL14-93	Westar Energy	Settlement - Uncontested	May-15	9.80	4.58	5.22
EL12-39	Duke Energy Florida	Settlement - Uncontested	Jun-15	10.00	4.65	5.35
ER14-192	SPS	Settlement - Uncontested	Jul-15	10.00	4.79	5.21
ER13-2428	Kentucky Utilities	Settlement - Uncontested	Jul-15	10.25	4.79	5.46
ER14-2751	XEST	Settlement - Uncontested	Sep-15	10.20	5.07	5.13

ER15-572	New York Transco LLC	Settlement - Uncontested	Oct-15	9.50	5.23	4.27
ER15-2237	Kanstar Transmission LLC	Settlement - Uncontested	Dec-15	9.80	5.41	4.39
ER15-2114	Transource West Virginia	Settlement - Uncontested	Dec-15	10.00	5.41	4.59

*Highlighted cases only included in MISO II

Cases removed from the Risk Premium Model

As noted above, the Commission refined the Risk Premium Model by, among other things, removing some cases from the analysis. A full list of those cases, along with the reason for their removal, is below:

Cases removed because the utility was merely adopting an existing ROE, such as the MISO ROE, without consideration of whether that ROE would be determined to be just and reasonable under fresh analysis:

- EL08-77, *Central Maine Power Co.*
- ER08-1548, *Northeast Utilities Service Co.*
- ER09-14, *NSTAR Elec. Co.*
- ER07-694, *New England Power Co.*
- EL10-80, *Ameren*
- ER12-1593, *DATC Midwest Holdings*
- ER12-2681, *ITC Holdings*

Cases removed because the ROE was clearly not under consideration:

- ER08-10, *Pepco Holdings, Inc.*
- ER11-3352, *PJM and Public Service Enterprise Group*

Cases removed for being duplicative:

- EL13-86, *Public Service Co. of Colorado*

Cases removed because the ROE was set for a definite future date, and the Commission could not have evaluated a risk premium for a future date:

- ER08-1457, *PPL Elec. Utilities Corp.*[436]

Cases removed because the test period predates 2006:

- EL05-19, *Golden Spread Electric Cooperative, Inc.*
- ER05-154, *Bangor Hydro Electric Company*

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[436] Only the 11.18% was removed from consideration. The other two resulting ROEs, because they were not solely applied to a future period, are still included in the analysis.

Appendix II: DCF Results

MISO I DCF Results

		Unadjusted Dividend Yield	Short-Term	Long-Term		Dividend Yield Adjustment	Adjusted Dividend Yield	DCF Results
Line	Company		Yahoo! Finance	GDP	Composite Growth	One-Step		
1	Consolidated Edison, Inc.	4.14%	2.38%	4.39%	2.78%	101.19%	4.19%	6.97%
2	Public Service Enterprise Group	3.74%	2.95%	4.39%	3.24%	101.48%	3.80%	7.03%
3	PPL Corporation	4.39%	2.23%	4.39%	2.66%	101.12%	4.44%	7.10%
4	CenterPoint Energy, Inc.	4.69%	1.91%	4.39%	2.41%	100.96%	4.73%	7.14%
5	IDACORP Inc.	3.04%	4.00%	4.39%	4.08%	102.00%	3.10%	7.18%
6	OGE Energy Corp.	3.09%	4.00%	4.39%	4.08%	102.00%	3.15%	7.23%
7	Westar Energy Inc.	3.74%	3.40%	4.39%	3.60%	101.70%	3.80%	7.40%
8	Portland General Electric Co.	3.11%	4.70%	4.39%	4.64%	102.35%	3.18%	7.82%
9	DTE Energy Co.	3.38%	4.51%	4.39%	4.49%	102.26%	3.46%	7.94%
10	PG&E Corp.	3.39%	4.71%	4.39%	4.65%	102.36%	3.47%	8.12%
11	The Southern Co.	4.62%	3.32%	4.39%	3.53%	101.66%	4.70%	8.23%
12	SCANA Corp.	3.91%	4.30%	4.39%	4.32%	102.15%	3.99%	8.31%
13	Xcel Energy Inc.	3.68%	4.69%	4.39%	4.63%	102.35%	3.77%	8.40%
14	NorthWestern Corp.	3.60%	5.00%	4.39%	4.88%	102.50%	3.69%	8.57%
15	Duke Energy Corp.	4.05%	4.49%	4.39%	4.47%	102.25%	4.14%	8.61%
16	American Electric Power Co. Inc.	3.68%	5.08%	4.39%	4.94%	102.54%	3.77%	8.72%
17	Vectren Corp.	3.46%	5.50%	4.39%	5.28%	102.75%	3.56%	8.83%
18	Alliant Energy Corp.	3.50%	5.45%	4.39%	5.24%	102.73%	3.60%	8.83%

19	Avista Corp.	3.93%	5.00%	4.39%	4.88%	102.50%	4.03%	8.91%
20	NextEra Energy, Inc.	2.94%	6.27%	4.39%	5.89%	103.14%	3.03%	8.93%
21	Pinnacle West Capital Corp.	3.74%	5.30%	4.39%	5.12%	102.65%	3.84%	8.96%
22	Empire District Electric Co.	4.12%	5.00%	4.39%	4.88%	102.50%	4.22%	9.10%
23	Dominion Resources, Inc.	3.58%	5.89%	4.39%	5.59%	102.95%	3.69%	9.28%
24	Eversource Energy (Northeast Utilities)	3.27%	6.60%	4.39%	6.16%	103.30%	3.38%	9.54%
25	Ameren Corp.	3.91%	5.85%	4.39%	5.56%	102.93%	4.02%	9.58%
26	El Paso Electric Co.	3.01%	7.00%	4.39%	6.48%	103.50%	3.12%	9.59%
27	ALLETE Inc.	3.85%	6.00%	4.39%	5.68%	103.00%	3.97%	9.64%
28	CMS Energy Corp.	3.35%	6.73%	4.39%	6.26%	103.37%	3.46%	9.72%
29	Great Plains Energy, Inc.	3.65%	6.37%	4.39%	5.97%	103.19%	3.77%	9.74%
30	Otter Tail Corp.	4.06%	6.00%	4.39%	5.68%	103.00%	4.18%	9.86%
31	Black Hills Corp.	3.28%	7.00%	4.39%	6.48%	103.50%	3.39%	9.87%
32	Sempra Energy	2.59%	7.93%	4.39%	7.22%	103.97%	2.69%	9.91%
33	Exelon	3.64%	6.81%	4.39%	6.33%	103.41%	3.76%	10.09%
34	PNM Resources	2.85%	8.56%	4.39%	7.73%	104.28%	2.97%	10.70%
35	UIL Holdings	3.59%	7.79%	4.39%	7.11%	103.90%	3.73%	10.84%
36	TECO Energy	4.61%	7.68%	4.39%	7.02%	103.84%	4.79%	11.81%
37	ITC Holdings Corp.	1.76%	11.66%	4.39%	10.21%	105.83%	1.86%	12.07%
38	Unitil Corp.	Merger						
39	MGE Energy	Merger						
40	Edison International	2.66%	0.37%	4.39%	1.17%	100.19%	2.66%	4.38%
41	FirstEnergy Corp.	3.97%	-0.64%	4.39%	0.37%	99.68%	3.96%	5.01%
42	Entergy Corp.	4.21%	-0.48%	4.39%	0.49%	99.76%	4.20%	5.36%

Moodys Baa Utility Bonds	4.65%
Low With Outlier Test	6.97%
High	12.07%

Midpoint	9.52%
Low-End Outlier Test	6.47%
High-End Outlier Test	17.67%
Mean	8.93%

MISO II DCF Results

			Short-Term	Long-Term		Dividend Yield Adjustment		
Line	Company	Unadjusted Dividend Yield	Yahoo! Finance	GDP	Composite	One-Step	Adjusted Dividend Yield	DCF Results
1	Consol. Edison, Inc.	4.08%	2.95%	4.35%	3.23%	101.48%	4.14%	7.37%
2	Westar Energy Inc.	3.70%	3.50%	4.35%	3.67%	101.75%	3.76%	7.43%
3	Portland General Electric Co.	3.33%	4.11%	4.35%	4.16%	102.06%	3.40%	7.56%
4	Vectren Corp.	3.10%	5.00%	4.35%	4.87%	102.50%	3.18%	8.05%
5	Amer. Elec. Power Co., Inc.	3.84%	4.47%	4.35%	4.45%	102.24%	3.93%	8.37%
6	Xcel Energy, Inc.	3.68%	4.68%	4.35%	4.61%	102.34%	3.77%	8.38%
7	SCANA Corp.	3.90%	4.45%	4.35%	4.43%	102.23%	3.99%	8.42%
8	PPL Corp.	4.67%	3.74%	4.35%	3.86%	101.87%	4.76%	8.62%
9	Great Plains Energy	3.83%	4.80%	4.35%	4.71%	102.40%	3.92%	8.63%
10	DTE Energy Co.	3.75%	5.00%	4.35%	4.87%	102.50%	3.84%	8.71%
11	Pinnacle West Capital Corp.	3.92%	4.95%	4.35%	4.83%	102.48%	4.02%	8.85%
12	Avista Corp.	3.98%	5.00%	4.35%	4.87%	102.50%	4.08%	8.95%
13	Dominion Resources, Inc.	3.72%	5.49%	4.35%	5.26%	102.75%	3.82%	9.08%
14	PG&E Corp.	3.50%	5.80%	4.35%	5.51%	102.90%	3.60%	9.11%
15	Alliant Energy	3.72%	5.55%	4.35%	5.31%	102.78%	3.82%	9.13%
16	ALLETE, Inc.	4.16%	5.00%	4.35%	4.87%	102.50%	4.26%	9.13%
17	Eversource Energy	3.39%	6.57%	4.35%	6.13%	103.29%	3.50%	9.63%
18	CMS Energy Corp.	3.36%	6.72%	4.35%	6.25%	103.36%	3.47%	9.72%
19	Ameren Corporation	3.96%	6.00%	4.35%	5.67%	103.00%	4.08%	9.75%
20	El Paso Elec. Co.	3.20%	7.00%	4.35%	6.47%	103.50%	3.31%	9.78%
21	Otter Tail Corp.	4.05%	6.00%	4.35%	5.67%	103.00%	4.17%	9.84%
22	NorthWestern Corp.	3.61%	6.81%	4.35%	6.32%	103.41%	3.73%	10.05%
23	WEC Energy Group, Inc.	3.58%	7.55%	4.35%	6.91%	103.78%	3.72%	10.63%
24	Sempra Energy	2.84%	9.35%	4.35%	8.35%	104.68%	2.97%	11.32%
25	PNM Resources, Inc.	2.92%	9.30%	4.35%	8.31%	104.65%	3.06%	11.37%
27	IDACORP, Inc.	3.03%	4.00%	4.35%	4.07%	102.00%	3.09%	7.16%
26	CenterPoint Energy, Inc.	5.47%	0.40%	4.35%	1.19%	100.20%	5.48%	6.67%
28	OGE Energy Corp.	3.81%	2.17%	4.35%	2.61%	101.09%	3.85%	6.46%
29	Public Service Enterprise Group	3.85%	1.38%	4.35%	1.97%	100.69%	3.88%	6.28%

30	FirstEnergy Corp.	4.51%	-0.92%	4.35%	0.13%	99.54%	4.49%	5.38%
31	Edison International	2.85%	-0.51%	4.35%	0.46%	99.75%	2.84%	3.92%
32	Black Hills Corp.	Merger						
33	Cleco Corp.	Merger						
34	Duke Enegy Corp.	Merger						
35	Empire District	Merger						
36	Exelon Corp.	Merger						
37	Hawaii Elec. Ind. Inc.	Merger						
38	ITC Holdings	Merger						
39	NextEra Energy Inc.	Merger						
40	Pepco Holdings Inc.	Merger						
41	Souther Co.	Merger						
42	TECO Energy Inc.	Merger						
43	UIL Energy	Merger						

Moodys Baa Utility Bonds	5.41%
Low With Outlier Test	7.37%
High	11.37%
Midpoint	9.37%
High-End Outlier Test	17.43%
Low-End Outlier Test	7.18%

Appendix III: Overall Results

MISO I	**Zone of Reasonableness**		**Lower Third**		**Middle Third**		**Upper Third**	
	Lower	**Upper**	**Lower**	**Upper**	**Lower**	**Upper**	**Lower**	**Upper**
DCF (1)	6.97%	12.07%	6.97%	8.67%	8.67%	10.37%	10.37%	12.07%
CAPM (2)	7.80%	13.09%	7.80%	9.56%	9.56%	11.33%	11.33%	13.09%
Risk Premium (3)	7.50%	12.70%	7.50%	9.23%	9.23%	10.97%	10.97%	12.70%
Average	7.42%	12.62%	7.42%	9.16%	9.16%	10.89%	10.89%	12.62%
Midpoint	**10.02%**							
Average Width of DCF and CAPM Zones of Reasonableness:					5.195			
Risk Premium ROE:		10.10%						
Risk Premium Imputed Zone of Reasonableness:					7.50%	to	12.70%	

MISO II	**Zone of Reasonableness**		**Lower Third**		**Middle Third**		**Upper Third**	
	Lower	**Upper**	**Lower**	**Upper**	**Lower**	**Upper**	**Lower**	**Upper**
DCF (4)	7.37%	11.37%	7.37%	8.70%	8.70%	10.04%	10.04%	11.37%
CAPM (5)	8.35%	12.63%	8.35%	9.78%	9.78%	11.20%	11.20%	12.63%
Risk Premium (6)	8.22%	12.36%	8.22%	9.60%	9.60%	10.98%	10.98%	12.36%
Average	7.98%	12.12%	7.98%	9.36%	9.36%	10.74%	10.74%	12.12%
Midpoint	**10.05%**							
Average Width of DCF and CAPM Zones of Reasonableness:					4.14			
Risk Premium ROE:		10.29%						
Risk Premium Imputed Zone of Reasonableness:					8.23%	to	12.37%	

(1) See Appendix II

(2) See Trial Staff Initial Br. (I), Attachment A to App. 2 at 6.

(3) See Appendix I

(4) See Appendix II

(5) See Trial Staff Initial Br. (II), Attachment A to App. 2 at 6.

(6) See Appendix I

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Association of Businesses Advocating Tariff Equity Docket No. EL14-12-004
Coalition of MISO Transmission Customers
Illinois Industrial Energy Consumers
Indiana Industrial Energy Consumers, Inc.
Minnesota Large Industrial Group
Wisconsin Industrial Energy Group

v.

Midcontinent Independent System Operator, Inc.
ALLETE, Inc.
Ameren Illinois Company
Ameren Missouri
Ameren Transmission Company of Illinois
American Transmission Company LLC
Cleco Power LLC
Duke Energy Business Services, LLC
Entergy Arkansas, Inc.
Entergy Gulf States Louisiana, LLC
Entergy Louisiana, LLC
Entergy Mississippi, Inc.
Entergy New Orleans, Inc.
Entergy Texas, Inc.
Indianapolis Power & Light Company
International Transmission Company
ITC Midwest LLC
Michigan Electric Transmission Company, LLC
MidAmerican Energy Company
Montana-Dakota Utilities Co.
Northern Indiana Public Service Company
Northern States Power Company-Minnesota
Northern States Power Company-Wisconsin
Otter Tail Power Company
Southern Indiana Gas & Electric Company

Arkansas Electric Cooperative Corporation Mississippi Delta Energy Agency Clarksdale Public Utilities Commission Public Service Commission of Yazoo City Hoosier Energy Rural Electric Cooperative, Inc.	Docket No.	EL15-45-001

v.

ALLETE, Inc.
Ameren Illinois Company
Ameren Missouri
Ameren Transmission Company of Illinois
American Transmission Company LLC
Cleco Power LLC
Duke Energy Business Services, LLC
Entergy Arkansas, Inc.
Entergy Gulf States Louisiana, LLC
Entergy Louisiana, LLC
Entergy Mississippi, Inc.
Entergy New Orleans, Inc.
Entergy Texas, Inc.
Indianapolis Power & Light Company
International Transmission Company
ITC Midwest LLC
Michigan Electric Transmission Company, LLC
MidAmerican Energy Company
Montana-Dakota Utilities Co.
Northern Indiana Public Service Company
Northern States Power Company-Minnesota
Northern States Power Company-Wisconsin
Otter Tail Power Company
Southern Indiana Gas & Electric Company

(Issued May 21, 2020)

GLICK, Commissioner, *concurring in part and dissenting in part*:

1. Today's order is yet another twist in the Commission's decade-long effort to adapt its methodology for setting public utilities' return on equity (ROE) to the low-interest rate conditions that have prevailed since the late 2000s. In that time, the Commission has proposed multiple different ways of dealing with the fact that its long-standing ROE methodology produces cost-of-equity estimates well below the ROEs it generally permitted public utilities to collect in the years before the Great Recession. The

Commission's most recent attempt to address this issue, Opinion No. 569,[1] was far from perfect. Nevertheless, I supported it because it represented a reasonable compromise that I hoped would bring some much-needed certainty and predictability to the Commission's approach to setting public utilities' ROEs.

2. So much for that. Today, we are once again changing course and revamping our ROE methodology. And, in so doing, we are sacrificing whatever certainty Opinion No. 569 might have provided.

3. In addition, I am particularly troubled that the Commission is portraying its change of heart as a dispassionate assessment of various technical questions—the comparative merits of one financial model, the right source of data for another, or the appropriate application of various assumptions. It is hard for me to believe that anyone buys that this latest twist is a genuine reassessment of those technical minutiae or that those details are what led Chairman Chatterjee to express his eagerness to consider rehearing requests at the December 2019 Open Meeting, before those requests were even filed. Instead, it appears that the Commission again has chosen a path directed by the results, in this case the perceived need to award a higher ROE, rather than the law and the facts.

4. In fairness, it may be that the methodology established in Opinion No. 569 would yield ROEs that are too low. And it may also be that the ROE established in this proceeding—10.02 percent—is a just and reasonable number. But, even so, the Commission must be transparent about the factors driving its decisionmaking process. If we think the ROEs set by the Commission's methodology are too low—or, for that matter, too high—we ought to say so and explain our reasoning, rather than pretending to be concerned only with the technical details of our models, data, and assumptions. Accordingly, I dissent in part because I do not believe that today's order adequately justifies several of the changes it adopts, even if the end result is an appropriate number.

5. Finally, today's order affirms the one aspect of Opinion No. 569 that merited a grant of rehearing. Opinion No. 569 declined to order refunds for a period in which everyone agrees customers paid an unjust and unreasonable rate. I continue to believe that decision was an abdication of our responsibility to protect consumers. As a result, I also dissent from the portion of today's order that affirms that decision.

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[1] *Ass'n of Bus. Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.*, Opinion No. 569, 169 FERC ¶ 61,129 (2019).

I. The Commission Must Stop the Endless Fiddling with Its ROE Methodology

6. Between 2011 and 2015, various entities representing customers' interests filed a series of complaints under section 206 of the Federal Power Act[2] (FPA) arguing that the base ROE available to transmission owners in ISO New England, Inc. and the Midcontinent Independent System Operator (MISO) was unjust and unreasonable. In Opinion No. 531, the Commission addressed the first of those complaints, with its most significant findings being that "anomalous capital market conditions" required the Commission to consider a variety of financial models and that those models supported an elevated ROE.[3] The Commission subsequently applied that approach to a similar complaint involving the MISO Transmission Owners.[4] Shortly thereafter, however, the D.C. Circuit vacated Opinion No. 531, sending it back to the Commission and the Commission back to the drawing board.[5] Following that remand, the Commission proposed to expressly rely on the four financial models considered in Opinion No. 531.[6] A year later, in Opinion No. 569, we narrowed it to two models, while making a number of changes to how we implemented those models.[7] Today, we're back up to three models, with another round of tweaks to those models.[8]

7. With the exception of the Commission's finding of anomalous market conditions, which at least hinted at its real concern, the Commission's various orders in this saga have suggested that each new iteration of its ROE methodology is a largely technical affair that turns on the Commission's evaluation of discrete issues with the various

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[2] 16 U.S.C. ¶ 824e (2018).

[3] *Coakley Mass. Attorney Gen. v. Bangor Hydro-Elec. Co.*, Opinion No. 531, 147 FERC ¶ 61,234, at PP 41, 152 (2014).

[4] *Ass'n of Businesses Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.*, Opinion No. 551, 156 FERC ¶ 61,234 (2016).

[5] *Emera Maine v. FERC*, 854 F.3d 9 (2017).

[6] *Ass'n of Bus. Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.*, 165 FERC ¶ 61,118 (2018) (Briefing Order).

[7] Opinion No. 569, 169 FERC ¶ 61,129.

[8] Although the complaints against the RTO-wide ROEs in MISO and ISO New England garnered the most attention, the last ten years have also seen a host of other complaints against individual transmission owner's ROEs, which have also been affected by the Commission's back-and-forth over these complaints.

financial models. In so doing, the Commission has added new models,[9] removed some of those models,[10] tweaked some of those models,[11] introduced new inputs,[12] modified existing inputs,[13] introduced new screens,[14] modified existing screens,[15] and even altered how the Commission places the ROE within the zone of reasonableness.[16] But, with each

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[9] *See, e.g.*, Opinion No. 551, 156 FERC ¶ 61,234 at P 9 (relying on four alternative models to place the ROE within the zone of reasonableness).

[10] *See, e.g.*, Opinion No. 569, 169 FERC ¶ 61,129 at PP 200, 340 (declining to rely on the Expected Earnings or Risk Premium methodologies). Indeed, at this point, the Commission has considered, but not relied on the risk premium model, Opinion No. 551, 156 FERC ¶ 61,234 at P 191, proposed relying on the risk premium model, Briefing Order, 165 FERC ¶ 61,118 at PP 18-19**,** declined to rely on the risk premium model, Opinion No. 569, 169 FERC ¶ 61,129 at P 340, and, with today's order, now elected to rely on the rely risk premium model, *Ass'n of Bus. Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.*, Opinion No. 569, 171 FERC ¶ 61,154, at P 104 (2020).

[11] *See, e.g.*, Opinion No. 569-A, 171 FERC ¶ 61,154 at P 107 (modifying the risk premium model to produce a zone of reasonableness rather than a single point estimate).

[12] *Compare* Opinion No. 569, 169 FERC ¶ 61,129 at P 274 (rejecting the use of *Value Line* short-term growth rates in the Capital Asset Pricing Model (CAPM)) *with* Opinion No. 569-A, 171 FERC ¶ 61,154 at P 78 ("clarify[ing]" that the Commission will consider *Value Line* short-term growth rates in the CAPM).

[13] *See, e.g.*, Opinion No. 569-A, 171 FERC ¶ 61,154 at P 57 (reducing the weighting of the long-term growth rate in the two-step Discounted Cash Flow model (DCF) from one-third to one-fifth).

[14] Briefing Order, 165 FERC ¶ 61,118 at P 54 (proposing a high-end outlier screen that would apply to "any proxy company whose cost of equity estimated with a given model is more than 150 percent of the median result of all of the potential proxy group members in that model"); Opinion No. 569, 169 FERC ¶ 61,129 at P 375 (adopting the proposed high-end outlier screen).

[15] *See, e.g.*, Opinion No. 569-A, 171 FERC ¶ 61,154 at P 154 (increasing the threshold for the high-end outlier test from 150 percent of the median of the zone of reasonableness to 200 percent of the median of the zone of reasonableness).

[16] *See, e.g.*, *id.* P 193 (changing the start points for setting ROEs for above- and below-average ROEs); Opinion No. 551, 156 FERC ¶ 61,234 at P 275 (setting the MISO-wide ROE at the midpoint of the upper half of the zone of reasonableness).

new twist, it becomes harder to buy that the Commission is genuinely reassessing the mechanics of each model rather than disagreeing with the ROE numbers those models produce.[17]

8. Today's order is the culmination of all that. Not long after completing a year-long process to re-evaluate our approach to setting ROEs following the D.C. Circuit's decision in *Emera Maine*, the Commission is now once again charting a major change of course. In so doing, the Commission is again portraying its change of heart as a technical matter based on its reassessment of a handful of discrete issues rather than what it is: A determination that the old number was too low and now we need a higher one.

9. To be fair, I am sympathetic to the impulse to consider subjective factors. The Commission's approach to setting a just and reasonable ROE will often implicate broader policy considerations, equity, and other factors that cannot be captured in, for example, a discussion of dividend yields or the appropriate sources of growth rate calculations. But while ROE policy will always be as much art as science, that is no excuse to pretend that art is science.

10. If broader considerations, including policy goals, are preventing the Commission from settling on or consistently applying an ROE methodology, then we must acknowledge those goals and give the interested entities the chance to weigh in on them just as they do for the intricacies of dividend yields, growth rates, and the like. All approaches to setting ROEs have their shortcomings, but the worst result by far is to continually fiddle with those approaches, undermining the certainty and predictability that help transmission owners make long-term investments. If the Commission is going to purport to rely entirely on financial models to evaluate and set ROEs, it has to take those models at face value without second-guessing them when it does not like the results.

11. In addition, today's order illustrates the problems with disguising subjective policy considerations as technical determinations. In a number of instances, the Commission is reversing determinations made in Opinion No. 569 using rationales that are far less convincing than those that supported the opposite outcome in Opinion No. 569. Shifting

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[17] It is also worth noting that, today, the Commission is adding even more complexity to its approach to setting ROE methodologies by also issuing a policy statement regarding oil and natural gas pipelines that largely follows the approach outlined in Opinion No. 569 rather than this order. In particular, that policy statement does not use the risk premium model, adjust the weighting of long- and short-term growth rates for the two-step DCF model, or adopt a particular high-end outlier screen. *See Policy Statement on Determining Return on Equity for Natural Gas and Oil Pipelines*, 171 FERC ¶ 61,155 at PP 2, 87 (2020). The Commission, it seems, just cannot settle on an analytically consistent approach to this important issue.

from such strong arguments to such suspect ones underscores the extent to which subjective factors seem to be operating in the background while also opening the Commission up to considerable risk on judicial review, creating even more of the uncertainty we ought to be trying to minimize.

12. Take the example of the risk premium model. Although Opinion No. 569 declined to utilize the risk premium model based on a long list of shortcomings, today's order reverses course, adding it to the DCF and CAPM on which the Commission previously relied. The record before us does not support that choice.

13. As an initial matter, and as explained in Opinion No. 569, the risk premium model does essentially the same thing as the CAPM by attempting to calculate the "premium that investors require over the risk-free rate of return."[18] Opinion No. 569 rightly pointed out that nothing in the record supports having two thirds of the Commission's ROE methodology composed of such analytically redundant approaches.[19] Today's order tersely responds to that concern by asserting that the two models are "sufficiently distinct" since they use different inputs.[20] But that ignores the point in Opinion No. 569 that the problem with relying on both models is that they replicate the same basic methodology, irrespective of their inputs.[21]

14. Opinion No. 569 also explained how the risk premium model is, in most respects, just an inferior version of the CAPM in so far as it does not consider market-based cost-of-equity estimates[22] and introduces significant circularity concerns by relying on *past*

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[18] Opinion No. 569, 169 FERC ¶ 61,129 at P 341.

[19] *Id.*

[20] Opinion No. 569-A, 171 FERC ¶ 61,154 at P 105.

[21] Opinion No. 569, 169 FERC ¶ 61,129 at P 341 ("We find that using the Risk Premium model in conjunction with the CAPM model would confer too much weight towards risk premium methodologies. The Commission has long used and, over time, refined the DCF model and we find that it would be inappropriate for variations of the risk premium model to receive twice its weight.").

[22] *Id.* P 342 ("[T]he Risk Premium model is likely to provide a less accurate current cost of equity estimate than the DCF model or CAPM because it relies on previous ROE determinations, whose resulting ROE may not necessarily be directly determined by a market-based method, whereas the DCF and CAPM methods apply a market-based method to primary data."). In addition, as the Commission noted, many of the ROEs included in the risk premium analyses in the record were never determined to be just and reasonable. For example, many of the ROEs were set through uncontested settlements, which involve compromise across a host of issues of which ROE is just one.

judgments, which may not reflect the appropriate risk premium under current conditions.[23] The Commission responds to those circularity concerns by contending that they are "mitigate[d]" by the fact that the Commission will average the results of the risk premium with the DCF and the CAPM, which do not present the same concerns.[24] But observing that the Commission will *also* use models without significant circularity concerns is not a reasoned response to the argument that you should not use circular models in the first place.

15. In addition, the Commission convincingly explained in Opinion No. 569 how "the record contains insufficient evidence to conclude that investors rely on risk premium analyses utilizing historic Commission ROE determinations or settlement approvals to determine the cost of capital and make investment decisions."[25] The Commission noted that, while allowed ROEs are certainly important to investors' decisionmaking, that does not suggest that investors' perform anything remotely close to the analysis contemplated by the risk premium model—*i.e.*, a backward looking comparison between riskless assets and allowed ROEs—when making their investment decisions.[26] Today's order now takes the opposite position, observing only that investors in regulated utilities expect to earn a return above a risk-free asset (which is obviously true) and that "investors . . . observe regulatory ROEs and how changes in authorized ROE levels could affect utility earnings" (which is equally obvious).[27] It should go without saying that investors pay attention to ROEs earned by public utilities and expect them to be higher than debt backed by the U.S. government. But neither of those self-evident statements provides *any* reason—much less substantial evidence—to believe that investors perform a risk premium analysis comparing past differences between risk free assets and Commission-allowed ROEs when evaluating whether to invest in Commission-regulated public utilities.

16. And, finally, the risk premium model does not at all fit with the Commission's new approach for evaluating whether an existing ROE is just and reasonable. Opinion No. 569 established a framework for evaluating whether an existing ROE is just and

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The Commission frequently approves uncontested without directly passing on whether the individual terms are just and reasonable. *See id.*

[23] *See id.* P 343 (explaining that the circularity concerns with the risk premium model are "particularly direct and acute").

[24] Opinion No. 569-A, 171 FERC ¶ 61,154 at P 106.

[25] Opinion No. 569, 169 FERC ¶ 61,129 at P 345.

[26] *Id.*

[27] Opinion No. 569-A, 171 FERC ¶ 61,154 at P 112.

reasonable based on ranges of presumptively just and reasonable results derived from the financial models used by the Commission.[28] Unlike every other financial model used, or even considered by the Commission in Opinion No. 569,[29] the risk premium model produces a single point estimate of the just and reasonable ROE, not a zone of reasonableness.[30]

17. Recognizing this "serious concern," but nevertheless determined to fit a square peg into a round hole, today's order resolves to "impute" the average width of the zone of reasonableness created by the DCF and CAPM methodologies to the risk premium model.[31] For example, if the DCF and CAPM produce an average zone of 200 basis points, it seems that the Commission will just assume that the risk premium model does too. Today's order, however, does not point to any evidence suggesting that such imputation is appropriate or that any investors or financial experts have sanctioned the Commission's method. Presumably that is because the record lacks any evidence supporting such an odd repurposing of the risk premium model.[32] After all, the Commission's approach to using the risk premium in evaluating whether an existing ROE is just and reasonable is the equivalent of making someone a "custom" suit based on their siblings' measurements: Maybe it will fit, but there is no reason to believe that it will and, in any case, it misses the point of the exercise.

18. In addition, today's order adopts a series of equally unreasoned modifications to Opinion No. 569's framework for conducting the first step of the section 206 inquiry. As noted, Opinion No. 569 established a practice of dividing the zone of reasonableness into ranges of presumptively just and reasonable ROEs within the broader zone of reasonableness.[33] In particular, the Commission created risk-adjusted "quartiles" of the

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[28] Opinion No. 569, 169 FERC ¶ 61,129 at P 57.

[29] The Commission also considered, but rejected, relying upon an expected earnings model as well. *Id.* P 200.

[30] *Id.* P 351.

[31] Opinion No. 569-A, 171 FERC ¶ 61,154 at P 107.

[32] That become especially clear when compared with the Commission's thorough and well-reasoned rejection of the risk premium on this basis, among others, in Opinion No. 569. *Compare id* P 107 *with* Opinion No. 569, 169 FERC ¶ 61,129 at P 351.

[33] That change responded to the D.C. Circuit's holding that the FPA contemplates "a 'broad' range of potentially just and reasonable ROEs, 'not an exact dollar figure.'" *Emera Maine v. FERC*, 854 F.3d 9, 23 (D.C. Cir. 2017) (quoting *Panhandle E. Pipe Line Co. v. FERC*, 777 F.2d 739, 746 (D.C. Cir. 1985)).

zone of reasonableness centered on the three points that the Commission uses as the starting point for setting ROEs for utilities of different risk profiles[34]—the midpoint of the entire zone of reasonableness for average-risk utilities, the midpoint of the lower half of the zone of reasonableness for below-average risk utilities, and the midpoint of the upper half of the zone of reasonableness for above-average risk utilities.[35]

19. The Commission justified the end points of each quartile by explaining that "[l]ogic dictates that the end points of those ranges should not be closer to the starting points for the ranges of utilities with different risk profiles than they are to their own starting point."[36] In other words, it would not make sense to presume that an existing ROE is just and reasonable if it was closer to the starting point used to set the ROE for a utility of a different risk profile than the starting point for a utility of the same risk profile. The Commission's quartile-based approach made sense given the emphasis that the Commission has historically placed on relative risk profiles when placing ROEs within the zone of reasonableness[37] and it ensured that the ranges of presumptively just and reasonable results were not just arbitrary sub-sections of the zone of reasonableness.

20. Today's order abandons that well-reasoned approach and arbitrarily divides the entire zone of reasonableness into thirds, with each third providing a presumptively just and reasonable range of ROEs for certain utilities. The Commission appears to suggest[38] that this maneuver is necessary to comply with the D.C. Circuit's statement in *Emera Maine* that "the zone of reasonableness creates a broad range of *potentially* lawful

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[34] Opinion No. 569, 169 FERC ¶ 61,129 at P 57.

[35] *Id*. The midpoint is the measure of central tendency that the Commission uses when setting the ROE for a diverse range of utilities. *Id.* PP 398, 409. By contrast, the Commission uses the median as the measure of central tendency when setting the ROE for a single utility. *Id.* P 398.

[36] *Id.* P 63.

[37] *See* Opinion No. 569, 169 FERC ¶ 61,129 at P 62 ("We also find that the circumstance most relevant to determining that range is the utility's risk profile."); *see also FPC v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944) ("[T]he return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks."); *Petal Gas Storage, L.L.C. v. FERC*, 496 F.3d 695, 6-99700 (D.C. Cir. 2007) (explaining the emphasis that the Commission and courts have placed on the role of risk in setting ROEs).

[38] Opinion No. 569-A, 171 FERC ¶ 61,154 at P 190.

ROEs."[39] But *Emera Maine* requires nothing of the sort. Read in context, the quoted language stands only for the proposition that the Commission cannot prove that an existing rate is unjust and unreasonable simply by showing that its ROE methodology would produce a different number using current data.[40] The court certainly did not suggest that every point within the zone of reasonableness must be *presumptively* just and reasonable for some utility, which is how today's order appears to understand that language. In any case, the quartile-based approach in Opinion No. 569 easily complied with even the Commission's reading of the language in *Emera Maine*. Because the ranges only represented presumptive findings, a public utility could still argue that an ROE outside those ranges was nevertheless just and reasonable based on other considerations,[41] making every ROE within the zone of reasonableness at least "potentially" just and reasonable.

21. And that's just the start of it. Recognizing that the decision to divide the zone of reasonableness into thirds obliterates the rationale for the ranges outlined in Opinion No. 569,[42] the Commission announces, without any explanation, that it will change the starting points it uses when setting the ROE for below- and above-average risk utilities to the midpoint of the lower third of the zone of reasonableness and the midpoint of the upper third of the zone of reasonableness, respectively.[43] Now the tail is truly wagging the dog. In Opinion No. 569, the Commission justified the ranges of presumptively just and reasonable ROEs based on the Commission's longstanding approach to handling companies' relative risk profiles, namely the use of the upper and lower midpoints for utilities of above- and below-average risk, respectively.[44] In today's order, the Commission uproots that longstanding approach, selecting entirely new starting points for placing ROEs within the zone of reasonableness in order to support its new ranges of

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[39] *Emera Maine*, 854 F.3d at 26 (emphasis added).

[40] *Id.* ("But, as we have explained, the zone of reasonableness creates a broad range of potentially lawful ROEs rather than a single just and reasonable ROE, meaning that FERC's finding that 10.57 percent was a just and reasonable ROE, standing alone, did not amount to a finding that every other rate of return was not." (internal quotation marks omitted)).

[41] Opinion No. 569, 169 FERC ¶ 61,129 at PP 60-64, 68 (discussing how the Commission would apply the new framework, including what other factors it would consider).

[42] *See supra* P 20 & note 37.

[43] Opinion No. 569-A, 171 FERC ¶ 61,154 at 194.

[44] Opinion No. 569, 169 FERC ¶ 61,129 at PP 62-64.

presumptively just and reasonable results. That gets it entirely backwards; the ranges of presumptively just and reasonable results should reflect how we set ROEs, not the other way around. In any case, at no point in today's order does the Commission explain why the new starting points themselves are an appropriate place to begin the process of placing the ROE for an above- or below-average risk utility within the zone of reasonableness.[45]

22. Suffice it to say, the Commission has not justified its change of course with respect to either the risk premium model or its approach to step one of the section 206 inquiry. Nevertheless, while I believe that Opinion No. 569 was a superior approach to setting ROEs, I also recognize that the roughly 10 percent ROE established in today's order may well be a just and reasonable end result.[46] In addition, for the reasons explained above, I firmly believe that the Commission must finally bring some certainty and predictability to how its sets transmission owner ROEs.

II. The Commission Should Order Refunds for Unjust and Unreasonable Rates Paid by Consumers

23. I continue to disagree with the Commission's refusal to order refunds for the fifteen-month refund period established pursuant to the Second Complaint.[47] Throughout that period, customers within MISO paid an unjust and unreasonable ROE. Nevertheless, the Commission refuses to order refunds on the specious basis that the FPA requires it to act as if the 10.02 percent ROE set in today's order was in effect throughout that fifteen-month period. In reality, however, customers actually paid a 12.38 percent ROE—a difference worth tens of millions of dollars—and nothing in the law requires us to pretend otherwise.

24. The facts relevant to the issue of refunds are straightforward. On November 12, 2013, multiple parties filed a complaint (First Complaint) alleging that the MISO Transmission Owners' 12.38 percent ROE was unjust and unreasonable.[48] The

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[45] That failure is particularly glaring because the new starting points will be closer to either the top or bottom of the zone of reasonableness than the midpoint. Nothing in today's order—or the record before us—explains why those starting points should be biased towards the most extreme costs of equity in the zone of reasonableness.

[46] *Cf. Hope*, 320 U.S. 591, 602 (1944) ("Under the statutory standard of 'just and reasonable' it is the result reached not the method employed which is controlling.").

[47] *See* Opinion No. 569, 169 FERC ¶ 61,129 (Glick, Comm'r, dissenting in part).

[48] *Id.* P 3. The authorized base ROE for the ATCLLC zone was 12.20 percent, but I will follow the underlying order's practice of referring to the MISO-wide ROE as 12.38.

Commission set the matter for hearing and established a refund effective date of November 12, 2013 (the date the First Complaint was filed),[49] meaning that the 15-month refund period for the First Complaint lasted until February 12, 2015.[50] On February 12, 2015, a different set of parties filed another complaint (Second Complaint) against the MISO Transmission Owners' ROE. The Commission again set the matter for hearing and established a refund effective date of February 12, 2015,[51] meaning that the 15-month refund period for the Second Complaint lasted until May 12, 2016. Both proceedings were fully litigated and produced initial decisions by Administrative Law Judges.[52] And, in both cases, the Commission did not get around to issuing orders on the initial decisions until well after both refund periods expired, meaning that customers paid rates reflecting a 12.38 percent ROE throughout both refund periods.[53]

25. In today's order, the Commission affirms its conclusion in Opinion No. 569 that the 12.38 percent ROE was unjust and unreasonable and it establishes a new just and reasonable ROE of 10.02 percent. That is sufficient to order refunds for the refund

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Id. P 3 & n.11.

[49] *Ass'n of Bus. Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.*, 149 FERC ¶ 61,049, at P 188 (2014), *order on reh'g*, 156 FERC ¶ 61,060 (2016).

[50] As discussed further below, pursuant to the Regulatory Fairness Act, Pub. L. No. 100-473, § 2, 102 Stat 2299 (1988) (codified at 16 U.S.C. § 824e(b)), as part of any proceeding under section 206 of the FPA, the Commission shall establish a refund effective date and, at the conclusion of that proceeding, it may order refunds for the difference between an unjust and unreasonable rate in effect during the period up to 15 months following the refund effective date and the new just and reasonable rate fixed by the Commission.

[51] *Ark. Elec. Coop. Corp. v. ALLETE, Inc.*, 151 FERC ¶ 61,219, at P 1 (2015), *order on reh'g*, 156 FERC ¶ 61,061 (2016) (Second Complaint Rehearing Order).

[52] *Ass'n of Bus. Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.*, 153 FERC ¶ 63,027 (2015); *Ark. Elec. Coop. Corp. v. ALLETE, Inc.*, 155 FERC ¶ 63,030 (2016).

[53] The Commission originally issued an order on the First Complaint in September 2016. *See Ass'n of Businesses Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.*, Opinion No. 551, 156 FERC ¶ 61,234, at P 9 (2016). But, shortly thereafter, the D.C. Circuit issued its opinion in *Emera Maine*, 854 F.3d 9, which vacated the precedent on which Opinion No. 551 relied. Following briefing on remand, the Commission issued Opinion No. 569, which elicited the rehearing requests addressed in today's order.

periods established pursuant to *both* the First and Second Complaints. To see why, let's start with the text of section 206(b), which provides that

> At the conclusion of any proceeding under this section [i.e., section 206], the Commission may order refunds of any amounts paid, for the period subsequent to the refund effective date through a date fifteen months after such refund effective date, in excess of those which would have been paid under the just and reasonable rate, charge, classification, rule, regulation, practice, or contract which the Commission orders to be thereafter observed and in force.[54]

All that text requires is that the Commission find that customers paid an unjust and unreasonable rate during the refund period and that the Commission have set a just and reasonable replacement rate, so that it can calculate refunds equal to the difference between those two rates. Both conditions are satisfied here: Customers paid 12.38 percent through the Second Complaint refund period and the Commission has determined that they should have paid 10.02 percent. That is sufficient to order refunds pursuant to section 206(b).

26. Contrary to the suggestion in today's order,[55] the text of section 206(b) does not limit the Commission's refund authority to only those individual proceedings in which it sets a new rate. Instead, it provides the Commission with the authority to order refunds "[a]t the *conclusion* of *any* proceeding under this section"—*i.e.*, section 206."[56] Congress surely understood that not every section 206 proceeding would be resolved against the public utility and, had it so desired, it could have conditioned the Commission's refund authority accordingly. But by pairing the word "conclusion"—which would seem to contemplate proceedings in which the public utility prevailed as well as those in which it did not—with the phrase "any proceeding"—which is equally unlimited—Congress rejected such a narrow interpretation of the Commission's refund authority. Instead, as noted, the plain text of section 206 indicates that the Commission's refund authority turns on the presence of a difference between the unjust and unreasonable rate that customers paid during the refund period and the just and reasonable rate that they should have paid, not whether the Commission set a new rate in every complaint it resolves.

27. Recognizing that Congress did not explicitly limit the Commission's refund authority, the Commission responds that it did so implicitly when it inserted the phrase

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[54] 16 U.S.C. § 824e(b) (emphasis added).

[55] Opinion No. 569-A, 171 FERC ¶ 61,154 at PP 260-262.

[56] 16 U.S.C. § 824e(b) (emphasis added).

"thereafter observed and in force" in section 206(b).[57] The idea, as I understand it, is that "thereafter observed and in force" is supposed to reflect Congress' understanding that the Commission would be setting a new rate in each complaint prior to ordering any refunds.[58] Thus, the argument appears to go, the Commission cannot order refunds unless it sets a new rate in the complaint corresponding to each individual refund period.

28. As an initial matter, that would be a remarkably convoluted way of limiting the Commission's refund authority under section 206. It envisions that, instead of limiting the Commission's refund authority in the statutory text that establishes the proceedings in which the Commission can order refunds, Congress elected to do so through an opaque reference in the discussion of how the Commission should calculate any refunds that it may order. That is a bizarre—and overly complicated—way to read an otherwise straightforward statute.[59]

29. In any case, the "thereafter observed and in force" language is better read as a reference to the identical language in section 206(a).[60] Under that reading, all that "thereafter observed and in force" does is clarify that the ceiling on the Commission's refund authority under section 206(b) is the difference between the rate in effect during the refund period and the just and reasonable rate that the Commission established pursuant to subsection 206(a).[61] In other words, that language specifies *how* the Commission should calculate any refunds it orders, not *when* it may order refunds. As noted, my reading makes far more sense given the fact that the "thereafter observed and in force" language appears in the portion of 206(b) that defines how the Commission should calculate refunds, not when it should order them. I see no reason to abandon that

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[57] Opinion No. 569-A, 171 FERC ¶ 61,154 at P 262.

[58] *Id.*

[59] *Cf. City of Anaheim v. FERC*, 558 F.3d 521, 525 (D.C. Cir. 2009) ("declin[ing] FERC's invitation to mangle the statute").

[60] *See* 16 U.S.C. § 824e(a) (requiring the Commission to establish a new just and reasonable rate to be "thereafter observed and in force" whenever it finds that an existing rate is unjust and unreasonable or unduly discriminatory or preferential).

[61] That interpretation makes even more sense when you consider that section 206(b) was added more than 50 years after section 206(a), which was part of the original FPA, and so it would have been necessary to clarify how the amendment worked in conjunction with the pre-existing language.

straightforward reading of the statute, which protects customers from paying unjust and unreasonable rates, in favor of a convoluted one that does not.[62]

30. The Commission's next argument is even more of a head scratcher. The Louisiana Public Service Commission argues that it is irrational to use the ROE set in Opinion No. 569 as the baseline for evaluating whether to order refunds for the Second Complaint refund period because that ROE was never "demanded, observed, charged, or collected," as section 206 requires. The Commission responds with what might charitably be called a regulatory fiction. It argues that Opinion No. 569 made the new just and reasonable ROE set in the First Complaint proceeding effective as of the beginning of the First Complaint refund period, which, the Commission argues, means that we must pretend that that lower ROE was in effect throughout the refund period for the Second Complaint as well. The Commission seems to be suggesting that it must pretend that the 10.02 ROE established today was "demanded, observed, charged, or collected" during the second refund period.[63]

31. But that interpretation is both demonstrably false and squarely foreclosed by section 206. First and foremost, the ROE that the MISO Transmission Owners collected during the refund period for the Second Complaint was 12.38 percent, no ifs, ands, or buts. In addition, the FPA flatly prohibited the MISO Transmission Owners from collecting any other ROE during that period. As noted, section 206 is forward looking in that it gives the Commission the ability to set a new just and reasonable rate as of the date on which the Commission makes the findings required by section 206.[64] The only exception to that rule is for the refund period, during which time the Commission is

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[62] *Cf., e.g.*, *California ex rel. Lockyer v. FERC*, 383 F.3d 1006, 1017 (9th Cir. 2004) (rejecting "an interpretation [that] comports neither with the statutory text nor with the Act's 'primary purpose' of protecting consumers"); *City of Chicago, Ill. v. FPC*, 458 F.2d 731, 751 (D.C. Cir. 1971) ("[T]he primary purpose of the Natural Gas Act is to protect consumers." (citing, *inter alia*, *City of Detroit v. FPC*, 230 F.2d 810, 815 (D.C. Cir. 1955)); S. Rep. 100-491, 5-6 (1988) ("The Committee intends the Commission to exercise its refund authority under section 206 in a manner that furthers the long-term objective of achieving the lowest cost for consumers consistent with the maintenance of safe and reliable service.").

[63] Opinion No. 569-A, 171 FERC ¶ 61,154 at P 264.

[64] *See, e.g.*, *Louisiana Pub. Serv. Comm'n v. FERC*, 772 F.3d 1297, 1299 (D.C. Cir. 2014) (explaining that section 206 provides for prospective relief only with the exception of the refund period).

permitted to act as if the new rate were in effect when ordering refunds.[65] The refund period for the Second Complaint, however, fell *after* the conclusion of the refund period for the First Complaint and *before* the date on which the Commission issued Opinion No. 569. Suffice it to say, it is arbitrary and capricious for the Commission to assume that it did that which it is legally prohibited from doing.

32. The Commission's next argument is that ordering refunds for the Second Complaint would represent an end-run around the 15-month limitation on refunds enshrined in section 206(b).[66] That argument appears to have both a legal dimension and a policy dimension. Beginning with the former, the Commission seems to be taking the position that ordering refunds in the Second Complaint period would effectively extend the refund period established for the First Complaint. But the Commission has repeatedly held that the FPA permits such successive or "pancaked" complaints, which are "'entirely new proceeding[s]'" and not "'duplicative proceeding[s] intended solely to expand the amount of refund protection beyond 15 months,'"[67] provided that they raise new facts or arguments,[68] which the Commission held that the Second Complaint did.[69] Accordingly, rather than extending the refund period for the First Complaint, ordering refunds pursuant to the Second Complaint would simply reflect the fact that the MISO Transmission Owners collected an unjust and unreasonable ROE during a period when all parties were on notice that the Commission might order refunds of such excessive rates.[70]

33. From the perspective of public policy, I recognize that permitting pancaked complaints with multiple refund periods may be sub-optimal. After all, pancaked complaints can create significant uncertainty in an area where certainty is especially

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[65] *Id.*

[66] Opinion No. 569-A, 171 FERC ¶ 61,154 at P 259.

[67] Second Complaint Rehearing Order, 156 FERC ¶ 61,061 at P 33 (quoting *Southern Co. Servs. Inc.*, 83 FERC ¶ 61,079, 61,386 (1998)).

[68] *Id.* P 33 ("[T]he Commission has allowed multiple complaints regarding the same ROE, where the subsequent complaints are based on new, more current data, explaining that this is particularly critical given that what is at issue is return on equity, which, in contrast to other cost of service issues can be particularly volatile. (internal alterations and quotation marks omitted)).

[69] *Id.* P 34.

[70] *Cf. La. Pub. Serv. Comm'n v. FERC*, 482 F.3d 510, 520 (D.C. Cir. 2007) (noting that the filing of a section 206 put all parties on notice of the possibility that the Commission would order refunds).

important as transmission owners decide whether and how to invest in transmission infrastructure. But the desirability of pancaked complaints is something for Congress to consider, not a reason for us to twist the text of the FPA. So long as the FPA and the Commission's precedents permit pancaked complaints, then the Commission should not let its antipathy toward such complaints prevent customers from receiving the refunds to which they are entitled.

For these reasons, I respectfully concur in part and dissent in part.

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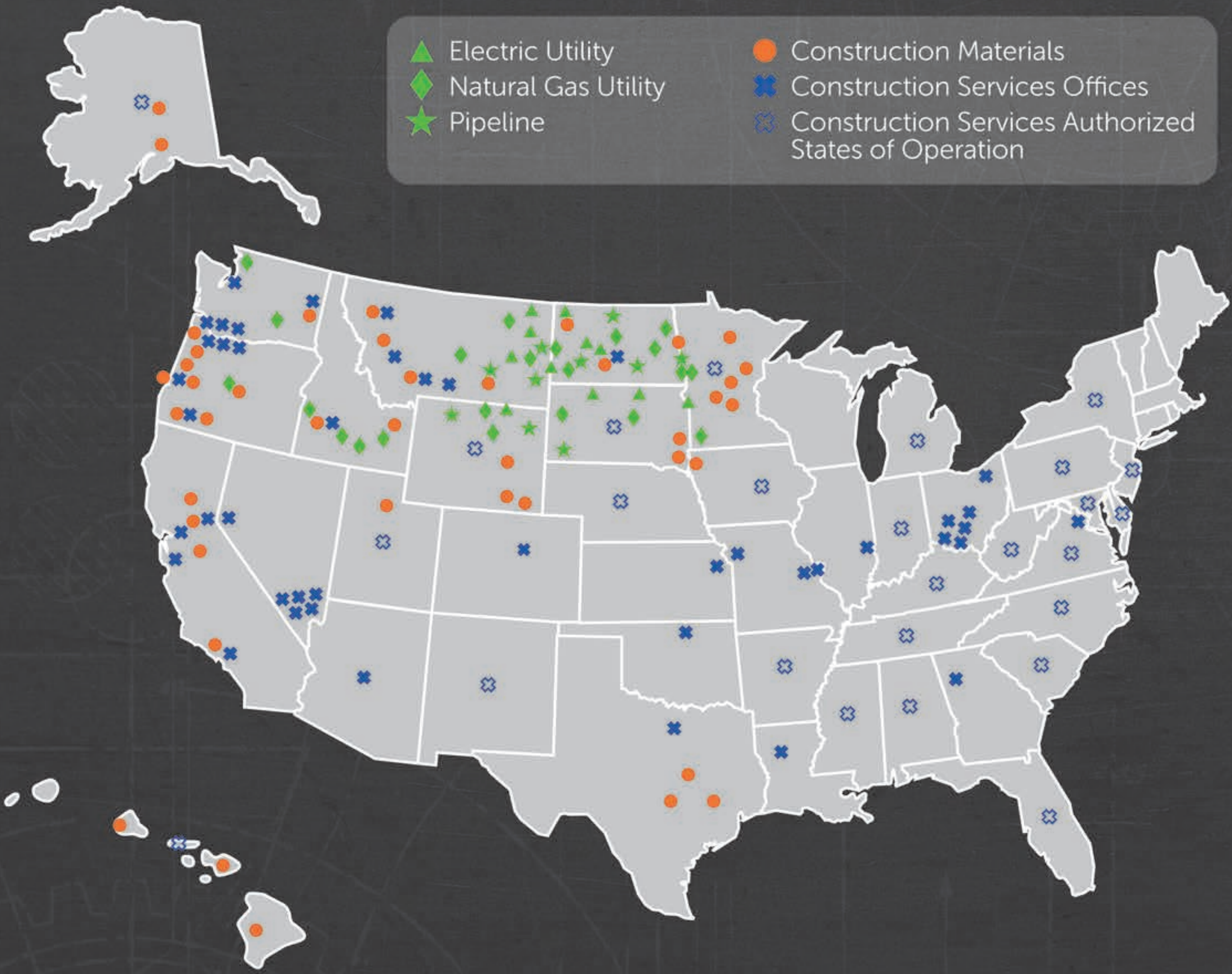
Richard Glick
Commissioner

2022

MDU RESOURCES
GROUP, INC.

Annual Report | Form 10-K | Proxy Statement

2022



MDU Resources Group, Inc., a member of the S&P MidCap 400 and S&P High-Yield Dividend Aristocrats indices, is Building a Strong America® by providing essential products and services through our regulated energy delivery and construction materials and services businesses.

MDU
LISTED
NYSE

MDU RESOURCES
GROUP, INC.

14,929
employees

2.4 Bcf/day
of natural gas pipeline capacity

1.18 million
utility customers

12th largest
specialty contractor,
according to Engineering News-Record

1.1 billion
tons of aggregate reserves

2022 annual dividend per share: 88 cents

Paid dividends 85 **consecutive years**

Increased dividends 32 **consecutive years**

2022 earnings:
$367.5 million / $1.81 EPS

At December 31, 2022.

Highlights

Years ended December 31,	**2022**	2021
	(In millions, where applicable)	
Operating revenues	**$6,973.9**	$5,680.7
Operating income	**$ 574.0**	$ 534.2
Net Income	**$ 367.5**	$ 378.1
Earnings per share	**$ 1.81**	$ 1.87
Dividends declared per common share	**$ .875**	$ .855
Weighted average common shares outstanding — diluted	**203.5**	202.4
Total assets	**$ 9,661**	$ 8,910
Total equity	**$ 3,587**	$ 3,383
Total debt	**$ 3,088**	$ 2,742
Capitalization ratios:		
Total equity	**53.7%**	55.2%
Total debt	**46.3**	44.8
	100%	100%
Price/earnings from continuing operations ratio (12 months ended)	**16.8x**	16.5x
Book value per share	**$ 17.62**	$ 16.64
Market value as a percent of book value	**172.2%**	185.3%
Employees	**14,929**	12,826

Forward-looking statements: This Annual Report contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Forward-looking statements should be read with the cautionary statements and important factors included in "Part I, Forward-Looking Statements" and "Item 1A — Risk Factors" of the company's "2022 Form 10-K." Forward-looking statements are all statements other than statements of historic fact, including without limitation those statements that are identified by the words anticipates, estimates, expects, intends, plans, predicts and similar expressions.

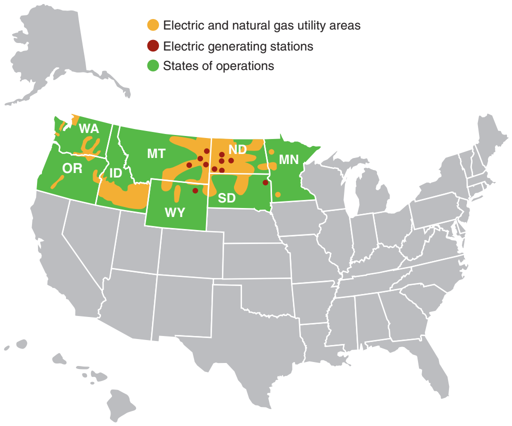
Our Businesses

Electric and Natural Gas Utilities

MDU Resources Group's utility companies serve approximately 1.18 million customers. Cascade Natural Gas Corporation distributes natural gas in Oregon and Washington. Intermountain Gas Company distributes natural gas in southern Idaho. Montana-Dakota Utilities Co. generates, transmits and distributes electricity and distributes natural gas in Montana, North Dakota, South Dakota and Wyoming. Great Plains Natural Gas Co., a division of Montana-Dakota Utilities, distributes natural gas in western Minnesota and southeastern North Dakota. These operations also supply related value-added services.

2022 Key Statistics

Revenues (millions)	
Electric	$377.1
Natural gas	$1,273.8
Net income (millions)	
Electric	$57.1
Natural gas	$45.2
Electric retail sales (million kWh)	3,343.9
Natural gas distribution (MMdk)	
Retail sales	131.2
Transportation sales	167.7

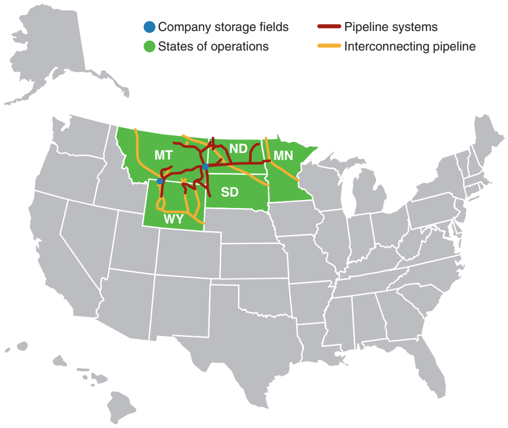


Pipeline

WBI Energy provides natural gas transportation and underground storage services through regulated pipeline systems primarily in the Rocky Mountain and northern Great Plains regions of the United States. It also provides cathodic protection and other energy-related services.

2022 Key Statistics

Revenues (millions)	$155.6
Net income (millions)	$35.3
Pipeline transportation (MMdk)	482.9

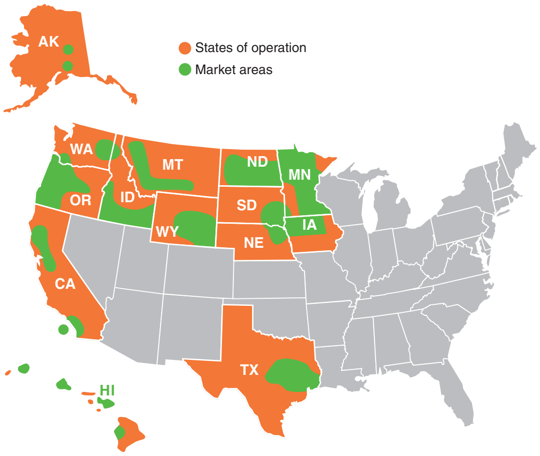


Construction Materials and Contracting

Knife River Corporation mines aggregates and markets crushed stone, sand, gravel and related construction materials, including ready-mix concrete, cement, asphalt, asphalt oil and other value-added products. It also performs integrated contracting services.

2022 Key Statistics

Revenues (millions)	$2,534.7
Net income (millions)	$116.2
Construction materials sales	
Aggregates (million tons)	34.0
Asphalt (million tons)	7.3
Ready-mix concrete (million cubic yards)	4.0
Construction materials aggregate reserves (billion tons)	1.1

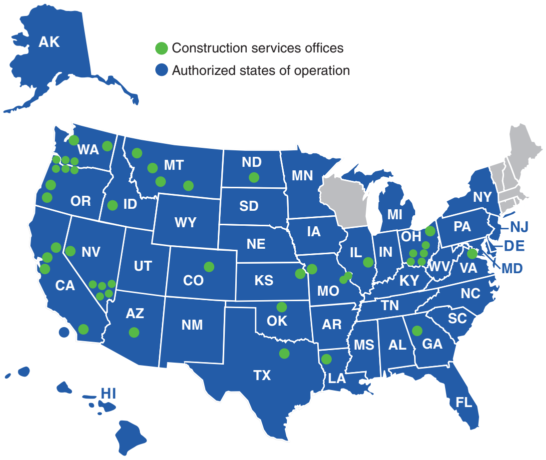


Construction Services

MDU Construction Services Group provides a full spectrum of construction services through its electrical and mechanical and transmission and distribution specialty contracting services across the United States. These specialty contracting services are provided to utility, manufacturing, transportation, commercial, industrial, institutional, renewable and governmental customers. Its electrical and mechanical contracting services include construction and maintenance of electrical and communication wiring and infrastructure, fire suppression systems, and mechanical piping and services. Its transmission and distribution contracting services include construction and maintenance of overhead and underground electrical, gas and communication infrastructure, as well as manufacturing and distribution of transmission line construction equipment and tools.

2022 Key Statistics

Revenues (millions)	$2,699.2
Net income (millions)	$124.8



Report to Stockholders

While our operations continued in 2022 to do what they do best — providing essential products and services that are Building a Strong America® — we also have been working toward significant strategic initiatives for our corporation. We announced in 2022 that our board has determined that moving toward two pure-play publicly traded companies, with one focused on regulated energy delivery and the other on construction materials, will unlock significant value for our shareholders. To achieve that objective, we announced on August 4 our intent to separate Knife River Corporation as an independent, publicly traded company. The spinoff is on track to be complete in the second quarter of 2023. Also, we announced on November 3 that we are undertaking a strategic review of MDU Construction Services Group, and we expect this to be complete in the second quarter as well.

Our objective is to make MDU Resources Group a pure-play energy delivery business, primarily electric and natural gas utilities along with a natural gas transmission pipeline business.

In 2022, MDU Resources had revenues of $6.97 billion and earnings of $367.5 million, or $1.81 per share, compared to revenues of $5.68 billion and earnings of $378.1 million, or $1.87 per share, in 2021. Costs associated with our strategic initiatives negatively impacted earnings in 2022 by $12.7 million, or 6 cents per share.

We increased our common stock dividend in 2022, for an annualized dividend of 89 cents per share. This is the 32nd consecutive year we have increased our dividend, and we have paid dividends uninterrupted for 85 years.

Utilities continue steady customer, rate base growth

Our electric and natural gas utilities earned $102.3 million in 2022, compared to earnings of $103.5 million in 2021. Retail sales volumes were 13.7 percent higher for natural gas and 2.2 percent higher for electricity. Increases in rates in certain jurisdictions, as approved by regulators, had a positive impact on the year's results, offset in part by higher operation and maintenance costs and higher interest expense.

Our utilities in 2022 continued their growth trajectory. Customer count grew by 1.6 percent, which aligns with our projected 1-2 percent annual growth over the longer term. We invested in this business to grow our rate base 7.8 percent in 2022. With anticipated capital investments of $2.1 billion through 2027, we expect rate base to continue to grow by approximately 6.5 percent on a compound annual basis for at least the next five years.

Our utilities again were recognized for providing superior customer service, with Cascade Natural Gas, Intermountain Gas and Montana-Dakota Utilities ranking first, third and sixth, respectively, among West Region midsize natural gas utilities in the J.D. Power 2022 Gas Utility Residential Customer Satisfaction Study. The study surveys customer satisfaction across six factors: safety and reliability, billing and payment, price, corporate citizenship, communications and customer care.

Our electric utility also was honored in 2022 by the Edison Electric Institute with an Emergency Response Award, which recognizes recovery and assistance efforts of electric companies following service disruptions from extreme weather or other natural events. Montana-Dakota's service territory was hit with widespread power outages during a late April blizzard in 2022. Rain that turned to thick ice on power lines, followed by 60 mph wind gusts, caused unprecedented system damage. Restoration was expected to take two weeks, but our team worked tirelessly

Earnings Per Share

Montana-Dakota Utilities crews work to restore power after unprecedented damage to company facilities from an April blizzard.

to restore service to our customers in just eight days, including replacing approximately 150 power poles and repairing about 350 crossarms in extremely difficult conditions.

Our electric utility continues to make progress toward its greenhouse gas emissions intensity reduction target of 45 percent by 2030, compared to 2005 levels, from owned generating facilities. In 2022, we ceased operations at our last wholly owned coal-fired electric generating facility, Heskett Station Units I and II in Mandan, North Dakota. As of the end of the year, we had reduced greenhouse gas emissions from owned generating facilities by approximately 40 percent. We expect construction to be complete this summer on Heskett Station Unit IV, an 88-megawatt natural gas-fired simple-cycle combustion turbine. This unit will be used primarily as a backup electric generation source when renewable sources may be unavailable.

WBI Energy's North Bakken Expansion project was placed into service in February 2022, and natural gas capacity usage will ramp up in 2023.

We announced in 2022 another Midcontinent Independent System Operator-approved joint regional transmission line project with Otter Tail Power Company. Together, we plan to develop, construct and co-own a 95-mile, 345-kilovolt transmission line that will span from Jamestown to Ellendale in North Dakota. MDU Resources will be responsible for half the investment, with the total project currently estimated at $439 million. The project creates a more resilient regional transmission grid, helping ensure continued reliable, affordable electric service to our customers. We are targeting a 2028 in-service date.

On the natural gas utility side of our business, we are investing in renewable natural gas opportunities. We have produced RNG from the Billings Regional Landfill in Montana since 2010 and have three dairy digesters in Idaho adding RNG to our system for customer use since 2020. We continue to explore additional RNG projects across our system and expect to have additional sources online soon.

Pipeline integrity remains another area of investment focus for our natural gas utilities as we continue to upgrade older natural gas distribution lines with lines made of newer materials, such as polyethylene and coated steel. We replaced approximately 90 miles of distribution lines in 2022.

Natural gas pipeline continues expanding

Dennis W. Johnson
Chair of the Board

David L. Goodin
President and Chief Executive Officer

Our natural gas pipeline business, WBI Energy, earned $35.3 million in 2022, compared to $40.9 million in 2021. WBI Energy achieved its sixth consecutive year of record transportation volumes through continued system expansions and steady customer demand. Results were negatively impacted by the absence of income recorded in 2021 as allowed by the Federal Energy Regulatory Commission for funds used during construction on the North Bakken Expansion project, as well as higher interest expense.

As we mentioned in last year's letter, the North Bakken Expansion project was in service in early 2022. We saw initial benefits from that project in 2022 and look forward to a full year of results in 2023 as customers' capacity usage ramps up.

We also completed a 10-mile expansion project in central North Dakota in 2022 to serve an ethanol plant. The project added approximately 6.7 million cubic feet per day of capacity to WBI Energy's system.

As of December 31, WBI Energy had total capacity to transport more than 2.4 billion cubic feet of natural gas per day on its system.

WBI Energy's natural gas pipeline system will continue to grow, with more expansion projects being planned than ever before. In 2023, significant projects include:

- Line Section 27 Expansion in northwestern North Dakota, which is expected to add transportation capacity of 175 million cubic feet per day and be in service in November.
- Grasslands South Expansion from western North Dakota to northern Wyoming, which is expected to add transportation capacity of 94 million cubic feet per day and be in service this fall.
- Line Section 15 Expansion in western South Dakota, which is expected to add transportation capacity of 25 million cubic feet per day and be in service in November.

In total, approximately 300 million cubic feet of additional natural gas transportation capacity is expected to be added in 2023, pending regulatory approval.

WBI Energy on January 27, 2023, filed a rate case with the FERC in which it is seeking rate increases for its transportation and storage services. We expect new rates to take effect by August 1.

Bakken-related development activity continues at a steady pace, and pipeline capacity is key to managing natural gas flaring. WBI Energy has a number of other projects in the queue for 2024 and beyond, including our Wahpeton Expansion Project. Pending regulatory approval, it is slated for construction in 2024 in southeastern North Dakota and would add much-needed capacity of nearly 21 million cubic feet of natural gas per day for the region.

WBI Energy sharpened its focus on reducing greenhouse gas emissions by establishing a methane emissions reduction target in 2022. WBI Energy has a near-term goal of reducing its methane emission intensity 25 percent by 2030 compared to 2020 levels, and it intends to establish a longer-term methane emission intensity reduction goal by 2030. In 2022, WBI Energy also joined the One Nation's Energy Future Coalition — ONE Future — which is a group of more than 50 natural gas companies working together to voluntarily reduce methane emissions across the industry to 1 percent or less by 2025.

Knife River overcoming inflationary pressures

Knife River Corporation earned $116.2 million in 2022, compared to $129.8 million in 2021. Revenues set a record at $2.53 billion, up 14 percent. While we were largely able to recover expense increases from inflationary pressures in 2022, margins were negatively impacted by cost increases on asphalt oil, labor, fuel and cement, as well as higher interest expense. Unfavorable weather early in the year and in the fourth quarter, which compressed the construction season for certain markets, also dampened results.

In addition to continuing to provide the products and services necessary for Building a Strong America,® Knife River was focused in 2022 on preparing to be spun off from MDU Resources as an independent, publicly traded company. Functions that have been provided at the MDU Resources level, such as information technology, accounting processes and human capital management, are being established to enable Knife River to stand separately from MDU Resources upon the anticipated spinoff in the second quarter.

Our board of directors appointed Brian Gray to be president of Knife River as of January 1, 2023, and just recently


The Knife River Training Center includes an 80,000-square-foot heated indoor arena for training truck drivers and heavy equipment operators.


MDU Construction Services Group subsidiary Bombard Renewable Energy finished construction on a 200-megawatt solar facility in Nevada.

announced that Brian also will become CEO of Knife River on March 1 as Dave Barney transitions to a senior advisor role. Brian has 29 years of experience with Knife River and was president of Knife River's Northwest Region since 2012.

Knife River's state-of-the-art construction training center in Oregon, which was fully operational in 2022, was recognized by Liberty Mutual with a prestigious Risk Management Excellence Award for its focus on safety in the construction industry. The center includes an 80,000-square-foot heated indoor arena for truck and heavy equipment training and a 16,000-square-foot office, classroom and lab facility on a 230-acre property that also allows for outdoor equipment training. With an emphasis on safety at all times, it provides both classroom and hands-on experience that will enhance the skills of current team members as well as recruit and train needed new team members.

Demand remains high for Knife River's construction materials products and contracting services. The company's backlog of work was a record $935 million at December 31, up 32 percent compared to $708 million at December 31, 2021. We expect strong ongoing growth opportunities for Knife River, including through projects that result from the U.S. Infrastructure Investment and Jobs Act that provides approximately $650 billion of reauthorized funds for the Department of Transportation surface transportation program and $550 billion of new infrastructure funds.

Records abound for construction services

MDU Construction Services Group earned $124.8 million in 2022, compared to $109.4 million in 2021. Revenues were a record $2.70 billion, compared to $2.05 billion in 2021. Electrical and mechanical services workload was particularly high for hospitality, data center and renewable projects. Utility-related transmission and distribution demand was steady as well, especially for power line fire-hardening work.

Demand continues to be extremely strong for construction services work, with MDU Construction Services Group having a record backlog of $2.13 billion at December 31, up 54 percent compared to $1.38 billion at December 31, 2021. MDU Construction Services Group also expects additional project opportunities to result from the Infrastructure Investment and Jobs Act funding.

With climbing backlog throughout 2022, this business also had a record number of employees during the year to meet project demand. MDU Construction Services Group employed approximately 9,000 skilled construction team members at December 31.

MDU Construction Services Group in 2022 was ranked the 12th largest specialty contractor in the United States by Engineering News-Record magazine and the fifth largest electrical contractor by Electrical Construction & Maintenance magazine.

An area of strong and growing demand for the construction services business continues to be what our team calls "mission critical" projects. We build hyperscale data centers for premier clients, and our superior expertise in this area provides industry-best performance to meet schedule and project costs.

MDU Construction Services Group continues to emphasize its premier services for renewable electric generation projects. Subsidiary Bombard Renewable Energy completed construction in October on a 200-megawatt solar facility in Moapa, Nevada. Bombard Renewable Energy installed 621,093 solar modules, as well as ancillary facilities, for the project.

While some things change, some remain the same

While our company footprint will change following the anticipated spinoff of Knife River and strategic review of MDU Construction Services Group, MDU Resources' philosophy toward the critical aspects of our business will remain the same as we become a pure-play energy delivery business.

We remain committed to operating with integrity and safety at the forefront of all that we do, while focusing on proper governance, environmental stewardship and stakeholder priorities, including returning value to you, our shareholders.

Thank you for your investment in MDU Resources.

Dennis W. Johnson
Chair of the Board

David L. Goodin
President and Chief Executive Officer

February 24, 2023

Board of Directors

Dennis W. Johnson
73 (22)
Dickinson, North Dakota

Chair of MDU Resources Board of Directors

Chair, president and chief executive officer of TMI Group, an architectural woodwork manufacturer; former president of the Dickinson City Commission; a former director of Federal Reserve Bank of Minneapolis.

Expertise: Business management, specialty contracting, finance and strategic planning.

David L. Goodin
61 (10)
Bismarck, North Dakota

President and Chief Executive Officer of MDU Resources

Formerly president and chief executive officer of Cascade Natural Gas Corporation, Great Plains Natural Gas Co., Intermountain Gas Company and Montana-Dakota Utilities Co.

German Carmona Alvarez
54 (1)
Wellington, Florida

Global president of applied intelligence of Wood PLC; formerly senior vice president and global digital practice leader of NEORIS and executive vice president of finance, information technology and shared services at CEMEX.

Expertise: Human capital management, digital and information technology, finance, and mergers and acquisitions.

Thomas Everist
73 (28)
Sioux Falls, South Dakota

President and chair of The Everist Co., formerly a construction materials company; a former director of Raven Industries, Inc., a public company.

Expertise: Construction materials and contracting industry, business leadership and management.

Karen B. Fagg
69 (18)
Billings, Montana

Retired, formerly vice president of DOWL HKM and formerly chair, chief executive officer and majority owner of HKM Engineering Inc.

Expertise: Engineering, natural resource development, environment and business management.

Patricia L. Moss
69 (20)
Bend, Oregon

Formerly vice chair, president and chief executive officer of Cascade Bancorp and Bank of the Cascades; a director of First Interstate BancSystem Inc., a public company.

Expertise: Finance, compliance oversight, business development and public company governance.

Dale S. Rosenthal
66 (2)
Washington, D.C.

Formerly strategic director of Clark Construction Group, LLC; a director of Washington Gas Light Company.

Expertise: Construction, alternative energy, infrastructure development, risk management and corporate strategy.

Edward A. Ryan
69 (5)
Washington, D.C.

Formerly executive vice president and general counsel of Marriott International, a large public company with international operations.

Expertise: Corporate governance and transactions, legal and public company leadership.

David M. Sparby
68 (5)
North Oaks, Minnesota

Formerly senior vice president and group president, revenue at Xcel Energy Inc. and president and chief executive officer of NSP-Minnesota.

Expertise: Public utility, renewable energy, finance, legal and public company leadership.

Chenxi Wang
52 (4)
Los Altos, California

Founder and managing general partner of Rain Capital Fund LP, a cybersecurity-focused venture fund; formerly chief strategy officer of Twistlock, a security software company.

Expertise: Technology, cybersecurity, capital markets and business development.

Audit Committee
David M. Sparby, Chair
Dale S. Rosenthal
Edward A. Ryan
Chenxi Wang

Compensation Committee
Karen B. Fagg, Chair
German Carmona Alvarez
Thomas Everist
Patricia L. Moss

Environmental and Sustainability Committee
Patricia L. Moss, Chair
Karen B. Fagg
David M. Sparby
Chenxi Wang

Nominating and Governance Committee
Edward A. Ryan, Chair
German Carmona Alvarez
Thomas Everist
Dale S. Rosenthal

Director Changes
German Carmona Alvarez was appointed to the Board of Directors on November 18, 2022.

Numbers indicate age and years of service ( ) on the MDU Resources Board of Directors as of December 31, 2022.

Corporate Management

David L. Goodin

61 (40)

President and Chief Executive Officer of MDU Resources

Serves on the company's Board of Directors and as chair of the board of all major subsidiary companies; formerly president and chief executive officer of Cascade Natural Gas Corporation, Great Plains Natural Gas Co., Intermountain Gas Company and Montana-Dakota Utilities Co.

David C. Barney

67 (37)

President and Chief Executive Officer of Knife River Corporation

Formerly held executive and management positions with Knife River.

Stephanie A. Barth

50 (27)

Vice President, Chief Accounting Officer and Controller of MDU Resources

Formerly controller of MDU Resources and vice president, treasurer and chief accounting officer of WBI Energy, Inc.

Trevor J. Hastings

49 (27)

President and Chief Executive Officer of WBI Energy, Inc.

Formerly vice president of business development and operations support of Knife River Corporation.

Anne M. Jones

59 (41)

Vice President and Chief Human Resources Officer of MDU Resources

Formerly vice president of human resources, customer service and safety of Cascade Natural Gas Corporation, Great Plains Natural Gas Co., Intermountain Gas Company and Montana-Dakota Utilities Co.

Nicole A. Kivisto

49 (28)

President and Chief Executive Officer of Cascade Natural Gas Corporation, Intermountain Gas Company and Montana-Dakota Utilities Co.

Formerly vice president of operations of Great Plains Natural Gas Co. and Montana-Dakota Utilities Co.

Karl A. Liepitz

44 (20)

Vice President, General Counsel and Secretary of MDU Resources

Serves as general counsel and secretary of all major subsidiary companies; formerly assistant general counsel and assistant secretary of MDU Resources.

Peggy A. Link

56 (18)

Vice President and Chief Information Officer of MDU Resources

Formerly assistant vice president of technology and cybersecurity officer of MDU Resources.

Jeffrey S. Thiede

60 (19)

President and Chief Executive Officer of MDU Construction Services Group, Inc.

Formerly held executive and management positions with MDU Construction Services Group.

Jason L. Vollmer

45 (18)

Vice President and Chief Financial Officer of MDU Resources

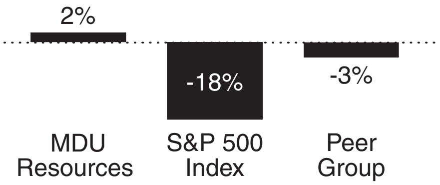
Formerly vice president, chief accounting officer and treasurer of MDU Resources.

Numbers indicate age and years of service ( ) as of December 31, 2022.

Stockholder Return Comparison

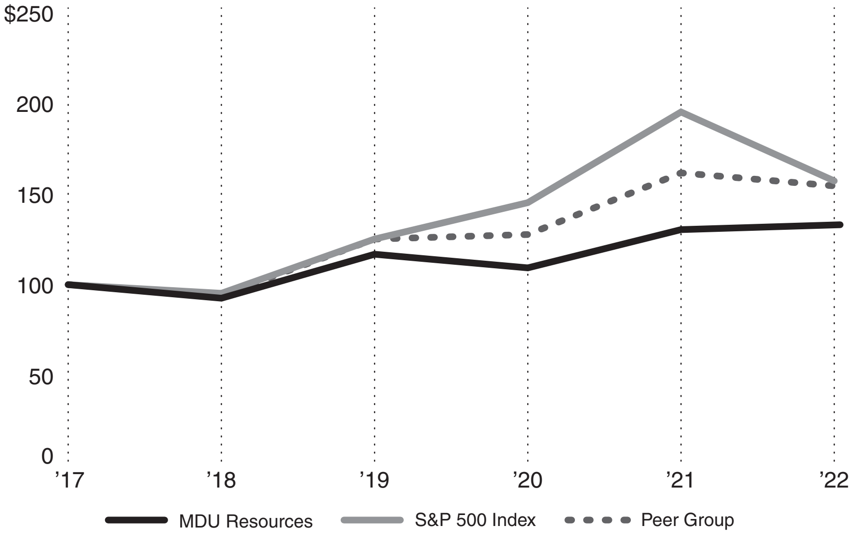
Comparison of One-Year Total Stockholder Return

(as of December 31, 2022)



Comparison of Five-Year Total Stockholder Return (in dollars)

$100 invested December 31, 2017, in MDU Resources was worth $131.40 at year-end 2022.



Company Name / Index	**12/31/17**	**12/31/18**	**12/31/19**	**12/31/20**	**12/31/21**	**12/31/22**
MDU Resources Group, Inc.	$100.00	$91.36	$117.34	$107.59	$129.51	$131.40
S&P 500 Index	100.00	95.62	125.72	148.85	191.58	156.88
Peer Group	100.00	94.84	125.08	126.38	160.10	155.39

Data is indexed to December 31, 2022, for the one-year total stockholder return comparison and December 31, 2017, for the five-year total stockholder return comparison for MDU Resources, the S&P 500 and the peer group. Total stockholder return is calculated using the December 31 price for each year. It is assumed that all dividends are reinvested in stock at the frequency paid, and the returns of each component peer issuer of the group are weighted according to the issuer's stock market capitalization at the beginning of the period.

The peer group issuers are Alliant Energy Corporation, Ameren Corporation, Atmos Energy Corporation, Black Hills Corporation, CMS Energy Corporation, Dycom Industries, Inc., EMCOR Group, Inc., Evergy, Inc., Granite Construction Incorporated, Jacobs Solutions Inc., KBR, Inc., Martin Marietta Materials, Inc., MasTec, Inc., NiSource Inc., Pinnacle West Capital Corporation, Portland General Electric Company, Quanta Services, Inc., Southwest Gas Holdings, Inc., Summit Materials, Inc., Vulcan Materials Company and WEC Energy Group, Inc.

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 1-03480

MDU RESOURCES GROUP INC

(Exact name of registrant as specified in its charter)

Delaware	30-1133956
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

1200 West Century Avenue
P.O. Box 5650
Bismarck, North Dakota 58506-5650
(Address of principal executive offices)
(Zip Code)

(701) 530-1000
(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 $1.00 per share	MDU	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 ☒.

State the aggregate market value of the voting common stock held by non-affiliates of the registrant as of June 30, 2022: $5,488,436,473.

Indicate the number of shares outstanding of the registrant's common stock, as of February 16, 2023: 203,623,893 shares.

DOCUMENTS INCORPORATED BY REFERENCE

Relevant portions of the registrant's 2023 Proxy Statement, to be filed no later than 120 days from December 31, 2022, are incorporated by reference in Part III, Items 10, 11, 12, 13 and 14 of this Report.

Contents

Part I

Part II

Part II (continued)

Part III

Part IV

Definitions

The following abbreviations and acronyms used in this Form 10-K are defined below:

Abbreviation or Acronym	
AFUDC	Allowance for funds used during construction
Army Corps	U.S. Army Corps of Engineers
ASC	FASB Accounting Standards Codification
ASU	FASB Accounting Standards Update
Audit Committee	Audit Committee of the board of directors of the Company
Bcf	Billion cubic feet
Big Stone Station	475-MW coal-fired electric generating facility near Big Stone City, South Dakota (22.7 percent ownership)
BSSE	345-kilovolt transmission line from Ellendale, North Dakota, to Big Stone City, South Dakota (50 percent ownership)
Btu	British thermal unit
CARES Act	United States Coronavirus Aid, Relief, and Economic Security Act
Cascade	Cascade Natural Gas Corporation, an indirect wholly owned subsidiary of MDU Energy Capital
Centennial	Centennial Energy Holdings, Inc., a direct wholly owned subsidiary of the Company
Centennial Capital	Centennial Holdings Capital LLC, a direct wholly owned subsidiary of Centennial
CERCLA	Comprehensive Environmental Response, Compensation and Liability Act
Code	The U.S. Internal Revenue Code, the highest form of tax law in the United States
Coincident Load Factor	The discount from peak requirements when the Company's peak is at a time different from the MISO system peak for the winter season.
Company	MDU Resources Group, Inc.
COVID-19	Coronavirus disease 2019
Coyote Creek	Coyote Creek Mining Company, LLC, a subsidiary of The North American Coal Corporation
Coyote Station	427-MW coal-fired electric generating facility near Beulah, North Dakota (25 percent ownership)
CyROC	Cyber Risk Oversight Committee
dk	Decatherm
Dodd-Frank Act	Dodd-Frank Wall Street Reform and Consumer Protection Act
EBITDA	Earnings before interest, taxes, depreciation, depletion and amortization
EIN	Employer Identification Number
EPA	United States Environmental Protection Agency
ERISA	Employee Retirement Income Security Act of 1974
ESA	Endangered Species Act
Exchange Act	Securities Exchange Act of 1934, as amended
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
Fidelity	Fidelity Exploration & Production Company, a direct wholly owned subsidiary of WBI Holdings (previously referred to as the Company's exploration and production segment)
FIP	Funding improvement plan
GAAP	Accounting principles generally accepted in the United States of America
GHG	Greenhouse gas
Grasslands Subsystem	A portion of WBI Energy Transmission's natural gas pipeline that runs from western North Dakota to north central Wyoming
Great Plains	Great Plains Natural Gas Co., a public utility division of Montana-Dakota
GVTC	Generation Verification Test Capacity
Holding Company Reorganization	The internal holding company reorganization completed on January 1, 2019, pursuant to the agreement and plan of merger, dated as of December 31, 2018, by and among Montana-Dakota, the Company and MDUR Newco Sub, which resulted in the Company becoming a holding company and owning all of the outstanding capital stock of Montana-Dakota.
IBEW	International Brotherhood of Electrical Workers
ICWU	International Chemical Workers Union
Intermountain	Intermountain Gas Company, an indirect wholly owned subsidiary of MDU Energy Capital
IPUC	Idaho Public Utilities Commission
IRA	Inflation Reduction Act
IRS	Internal Revenue Service

Item 8	Financial Statements and Supplementary Data
Knife River	Knife River Corporation, a direct wholly owned subsidiary of Centennial
Knife River Holding Company	The holding company established in conjunction with the proposed spinoff of Knife River
Knife River - Northwest	Knife River Corporation - Northwest, an indirect wholly owned subsidiary of Knife River
K-Plan	Company's 401(k) Retirement Plan
kW	Kilowatts
kWh	Kilowatt-hour
kV	Kilovolts
LIBOR	London Inter-bank Offered Rate
MD&A	Management's Discussion and Analysis of Financial Condition and Results of Operations
MDU Construction Services	MDU Construction Services Group, Inc., a direct wholly owned subsidiary of Centennial
MDU Energy Capital	MDU Energy Capital, LLC, a direct wholly owned subsidiary of the Company
MDUR Newco	MDUR Newco, Inc., a public holding company created by implementing the Holding Company Reorganization, now known as the Company
MDUR Newco Sub	MDUR Newco Sub, Inc., a direct, wholly owned subsidiary of MDUR Newco, which was merged with and into Montana-Dakota in the Holding Company Reorganization
MEPP	Multiemployer pension plan
MISO	Midcontinent Independent System Operator, Inc., the organization that provides open-access transmission services and monitors the high-voltage transmission system in the Midwest United States and Manitoba, Canada and a southern United States region which includes much of Arkansas, Mississippi and Louisiana
MMBtu	Million Btu
MMcf	Million cubic feet
MMdk	Million dk
MNPUC	Minnesota Public Utilities Commission
Montana-Dakota	Montana-Dakota Utilities Co. a direct wholly owned subsidiary of MDU Energy Capital
MPPAA	Multiemployer Pension Plan Amendments Act of 1980
MTDEQ	Montana Department of Environmental Quality
MTPSC	Montana Public Service Commission
MW	Megawatt
NDDEQ	North Dakota Department of Environmental Quality
NDPSC	North Dakota Public Service Commission
NERC	North American Electric Reliability Corporation
Oil	Includes crude oil and condensate
OPUC	Oregon Public Utility Commission
PCAOB	Public Company Accounting Oversight Board
PCBs	Polychlorinated biphenyls
PHMSA	Pipeline and Hazardous Material Safety Administration
Proxy Statement	Company's 2023 Proxy Statement to be filed no later than April 28, 2023
PRP	Potentially Responsible Party
Qualified Person	As defined by the SEC, a mineral industry professional with at least five years of relevant experience in the type of mineralization and type of deposit under consideration and in the specific type of activity that person is undertaking. The qualified person must also be an eligible member or licensee in good standing of a recognized professional organization.
RCRA	Resource Conservation and Recovery Act
RNG	Renewable Natural Gas
RP	Rehabilitation plan
SDPUC	South Dakota Public Utilities Commission
SEC	United States Securities and Exchange Commission
Securities Act	Securities Act of 1933, as amended
Sheridan System	A separate electric system owned by Montana-Dakota
SOFR	Secured Overnight Financing Rate
SPP	Southwest Power Pool, the organization that manages the electric grid and wholesale power market for the central United States.
UA	United Association of Journeyman and Apprentices of the Plumbing and Pipefitting Industry of the United States and Canada

Definitions

TSA	Transportation Security Administration
VIE	Variable interest entity
Washington DOE	Washington State Department of Ecology
WBI Energy	WBI Energy, Inc., an indirect wholly owned subsidiary of Centennial
WBI Energy Transmission	WBI Energy Transmission, Inc., an indirect wholly owned subsidiary of WBI Holdings
WBI Holdings	WBI Holdings, Inc., a direct wholly owned subsidiary of Centennial
WUTC	Washington Utilities and Transportation Commission
Wygen III	100-MW coal-fired electric generating facility near Gillette, Wyoming (25 percent ownership)
WYDEQ	Wyoming Department of Environmental Quality
WYPSC	Wyoming Public Service Commission
ZRCs	Zonal resource credits - a MW of demand equivalent assigned to generators by MISO for meeting system reliability requirements

Forward-Looking Statements

This Form 10-K contains forward-looking statements within the meaning of Section 21E of the Exchange Act. Forward-looking statements are all statements other than statements of historical fact, including without limitation those statements that are identified by the words "anticipates," "estimates," "expects," "intends," "plans," "predicts" and similar expressions, and include statements concerning plans, trends, objectives, goals, strategies, including the anticipated separation of Knife River or the proposed future structure of two pure-play publicly traded companies, future events, or performance, and underlying assumptions (many of which are based, in turn, upon further assumptions) and other statements that are other than statements of historical facts. From time to time, the Company may publish or otherwise make available forward-looking statements of this nature, including statements contained within Item 7 - MD&A - Business Segment Financial and Operating Data.

Forward-looking statements involve risks and uncertainties, which could cause actual results or outcomes to differ materially from those expressed. The Company's expectations, beliefs and projections are expressed in good faith and are believed by the Company to have a reasonable basis, including without limitation, management's examination of historical operating trends, data contained in the Company's records and other data available from third parties. Nonetheless, the Company's expectations, beliefs or projections may not be achieved or accomplished and changes in such assumptions and factors could cause actual future results to differ materially.

Any forward-looking statement contained in this document speaks only as of the date on which the statement is made and, except as required by law, the Company undertakes no obligation to update any forward-looking statement or statements to reflect events or circumstances that occur after the date on which the statement is made or to reflect the occurrence of unanticipated events, except as required by law. New factors emerge from time to time, and it is not possible for management to predict all of the factors, nor can it assess the effect of each factor on the Company's business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statement. All forward-looking statements, whether written or oral and whether made by or on behalf of the Company, are expressly qualified by the risk factors and cautionary statements in this Form 10-K, including statements contained within Item 1A - Risk Factors.

Items 1 and 2. Business and Properties

General

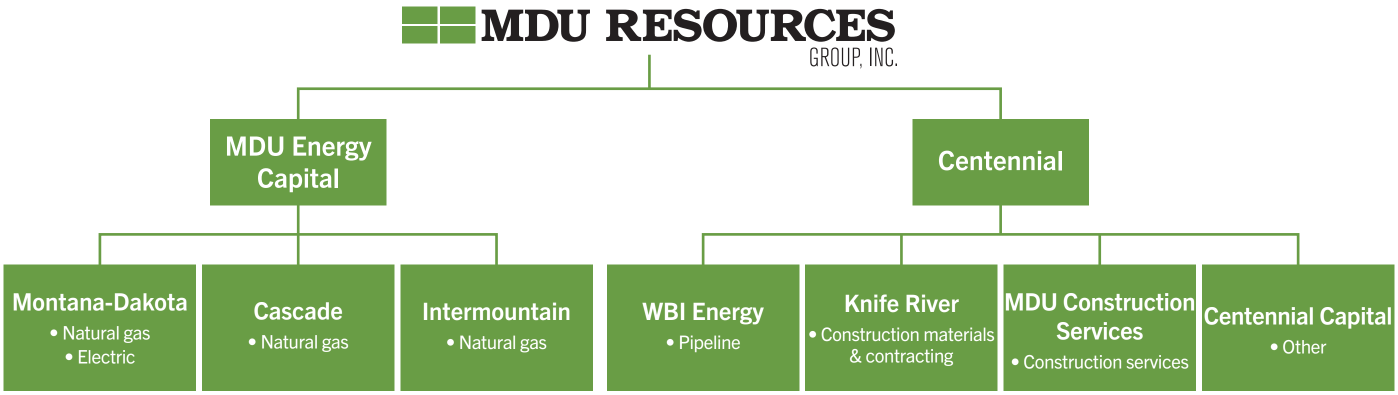
The Company is a regulated energy delivery and construction materials and services business. Its principal executive offices are located at 1200 West Century Avenue, P.O. Box 5650, Bismarck, North Dakota 58506-5650, telephone (701) 530-1000.

Montana-Dakota was incorporated under the state laws of Delaware in 1924. The Company was incorporated under the state laws of Delaware in 2018. Upon the completion of the Holding Company Reorganization, Montana-Dakota became a subsidiary of the Company. The Company's mission is to deliver superior value to stakeholders by providing essential infrastructure and services to America.

As part of the Company's continual review of its business, the Company announced strategic initiatives that are expected to enhance its value. On August 4, 2022, the Company announced its plan to separate Knife River, the construction materials and contracting business, from the Company, resulting in two independent, publicly traded companies. The separation of Knife River is planned as a tax-free spinoff transaction to the Company’s stockholders for U.S. federal income tax purposes. Completion of the separation will be subject to, among other things, the effectiveness of a registration statement on Form 10 with the SEC, final approval from the Company’s board of directors, receipt of one or more tax opinions and a private letter ruling from the IRS, and other customary conditions. The Company may, at any time and for any reason until the proposed transaction is complete, abandon the separation or modify or change its terms. The separation is expected to be complete in the second quarter of 2023, but there can be no assurance regarding the ultimate timing of the separation or that the separation will ultimately occur. On November 3, 2022, the Company announced its intention to create two pure-play publicly traded companies, one focused on regulated energy delivery and the other on construction materials, and that, to achieve this future structure, the board has authorized management to commence a strategic review process of MDU Construction Services. The strategic review is well underway and the Company anticipates completing it during the second quarter of 2023.

The Company's strategy is to deliver superior value and achieve industry-leading performance with two pure-play companies of regulated energy delivery and construction materials, while pursuing organic growth opportunities and strategic acquisitions of well-managed companies and properties. Through its regulated energy delivery businesses, the Company generates, transmits and distributes electricity and provides natural gas distribution, transportation and storage services. These businesses are regulated by state public service commissions and/or the FERC. The construction materials business provides construction materials through aggregate mining and marketing of related products, such as ready-mix concrete, asphalt and asphalt oil, and associated contracting services. The construction services business provides construction services through its electrical and mechanical and transmission and distribution specialty contracting services.

As of December 31, 2022, the Company was organized into five reportable business segments. These business segments include: electric, natural gas distribution, pipeline, construction materials and contracting, and construction services. The Company's business segments are determined based on the Company's method of internal reporting, which generally segregates the strategic business units due to differences in products, services and regulation. The internal reporting of these segments is defined based on the reporting and review process used by the Company's chief executive officer.



*Depicts the segment structure of the corporation; not the legal organization.

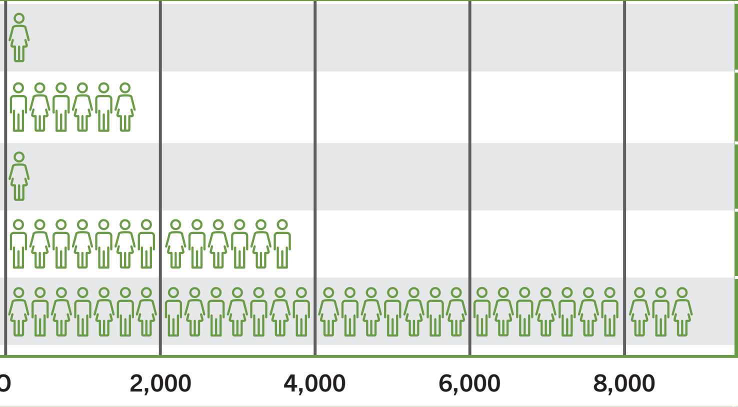
The Company, through its wholly owned subsidiary, MDU Energy Capital, owns Montana-Dakota, Cascade and Intermountain. The electric segment is comprised of Montana-Dakota while the natural gas distribution segment is comprised of Montana-Dakota, Cascade and Intermountain.

The Company, through its wholly owned subsidiary, Centennial, owns WBI Energy, Knife River, MDU Construction Services and Centennial Capital. WBI Energy is the pipeline segment, Knife River is the construction materials and contracting segment, MDU Construction Services is the construction services segment, and Centennial Capital is reflected in the Other category.

The financial results and data applicable to each of the Company's business segments, as well as their financing requirements, are set forth in Item 7 - MD&A and Item 8 - Note 17.

The Company's material properties, which are of varying ages and are of different construction types, are generally in good condition, are well maintained and are generally suitable and adequate for the purposes for which they are used.

Human Capital Management At the core of Building a Strong America® is building a strong workforce. This means building a strong team of employees with a focus on safety and a commitment to diversity, equity and inclusion. The Company's team was located in 44 states plus Washington D.C. as of December 31, 2022. The number of employees fluctuates during the year due to the seasonality and the number and size of construction projects. During 2022, the number of employees peaked in the third quarter at just over 16,800. Employees as of December 31, 2022, were as follows:



	Total	Male	Female
MDU Resources Group, Inc.	283	170	113
MDU Energy Capital	1,596	1,155	441
WBI Energy	321	260	61
Knife River	3,797	3,294	503
MDU Construction Services	8,932	8,238	694
MDU Resources Group, Inc. Total	14,929	13,117	1,812

Many of the Company's employees are represented by collective-bargaining agreements and the Company is committed to establishing constructive dialogue with this representation and bargain in good faith. The majority of the collective-bargaining agreements contain provisions that prohibit work stoppages or strikes and provide dispute resolution through binding arbitration in the event of an extended disagreement.

The following information is as of December 31, 2022.

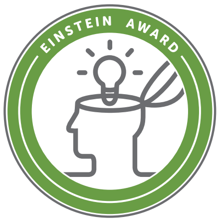
Company	Collective-bargaining agreement	Number of employees represented	Agreement status
Montana-Dakota	IBEW	313	Effective through April 30, 2024
Intermountain	UA	139	Effective through March 31, 2023
Cascade	ICWU	195	Effective through March 31, 2024
WBI Energy Transmission	IBEW	68	Effective through April 30, 2023
Knife River	40 various agreements	502	2 agreements in negotiations
MDU Construction Services	106 various agreements	7,588	No agreements in negotiations
Total		8,805	

Diversity, Equity and Inclusion The Company is committed to an inclusive environment that respects the differences and embraces the strengths of its diverse employees. Essential to the Company's success is its ability to attract, retain and engage the best people from a broad range of backgrounds and build an inclusive culture where all employees feel valued and contribute their best. To aid in the Company's commitment to an inclusive environment, each business segment has a diversity officer who serves as a conduit for diversity-related issues and provides a voice to all employees. The Company requires employees to participate in its Leading with Integrity training which provides training on the Company's code of conduct and additional courses focusing on diversity, effective leadership, equal employment opportunity, workplace harassment, respect and unconscious bias.

The Company has three strategic goals related to diversity:

- Enhance collaboration efforts through cooperation and sharing of best practices to create new ways of meeting employee, customer and stockholder needs.
- Maintain a culture of integrity, respect and safety by ensuring employees understand these essential values which are part of the Company's vision statement.
- Increase productivity and profitability through the creation of a work environment which values all perspectives and methods of accomplishing work.

The Company also promotes its strategic diversity goals through the following special recognition awards:



The **Einstein Award** recognizes the best process improvement ideas that contribute in a measurable way to improving the Company's bottom line and are vital to the Company's success.

The **Community Spirit Award** recognizes employees who are actively involved in their community.

The **Summit Award** recognizes employees who make the Company a better place to work.

The **Environmental Sustainability Award** recognizes an employee program, project or activity that reflects the Company's environmental policy and philosophy.

The **Hero Award** recognizes employees who go above and beyond the call of duty to save another's life.

In March 2022, the chief executive officer of the Company joined more than 2,000 chief executive officers in signing the CEO Action for Diversity and Inclusion Pledge. Through this collaboration with other companies, the Company furthers its commitment to a diverse and inclusive environment that respects the differences and embraces the strengths of its employees to further its corporate vision.

Building People Building a strong workforce begins with employee recruitment. The Company hires and trains employees to have the skills, abilities and motivation to achieve the results needed for their jobs. Each job is important and part of a coordinated team effort to accomplish the organization's objectives. The Company uses a variety of means to recruit new employees for open positions including posting on the Company's website at www.jobs.mdu.com, which is not incorporated by reference herein. Other sources for employee recruitment include employee referrals, union workforce, direct recruitment, advertising, social media, career fairs, partnerships with colleges and technical schools, job service organizations and associations connected with a variety of professions. The Company also uses internship programs to introduce individuals to the Company's business operations and provide a possible source of future employees.

Building a strong workforce also requires developing employees in their current positions and for future advancement. The Company provides opportunities for advancement through job mobility, succession planning and promotions both within and between business segments. The Company provides employees the opportunity to further develop and grow through various forms of training, mentorship programs and internship programs, among other things.

To attract and retain employees, the Company offers:

Compensation
Competitive salaries and wages based on the labor markets in which it operates.

Growth & Development
Employee growth through training in the form of technical, professional and leadership programs, as well as formal and informal mentoring and job shadowing programs to assist employees in their job and career goals.

Incentives
Incentive compensation based on the Company's performance.

Benefits
Comprehensive benefits including vacation, sick leave, health and wellness programs, retirement plans and discount programs.

The Company conducts employee surveys to hear and gauge employee opinions on issues such as fairness, camaraderie and pride in the workplace. Survey responses are compiled and evaluated at various levels throughout the Company to develop action plans to address areas of concern raised by employees.

Safety Safety is a corporate value and top priority of the Company. The Company is committed to safety and health in the workplace. To ensure safe work environments, the Company provides training, adequate resources and appropriate follow-up on any unsafe conditions or actions. To facilitate a strong safety culture, the Company established its Safety Leadership Council. In addition to the Safety Leadership Council, the Company has policies and training that support safety in the workplace including training on safety matters through classroom and toolbox meetings on job sites. The Company utilizes safety compliance in the evaluation of employees, which includes management, and recognizes employee safety through safety award programs. Accident and safety statistical information is gathered for each of the business segments and regularly reported to management and the board of directors.

Environmental Matters The Company believes it has a responsibility to use natural resources efficiently and attempt to minimize the environmental impact of its activities. The Company produces GHG emissions primarily from its fossil fuel electric-generating facilities, as well as from natural gas pipeline and storage systems, and operations of equipment and fleet vehicles. The Company has developed renewable generation with lower or no GHG emissions. Governmental legislation and regulatory initiatives regarding environmental and energy policy are continuously evolving and could negatively impact the Company's operations and financial results. As legislation and regulation are finalized, the impact of these measures can be assessed. The Company will continue to monitor legislative and regulatory activity related to environmental and energy policy initiatives. In addition, for a discussion of the Company's risks related to environmental laws and regulations, see Item 1A - Risk Factors.

The Company operates with three primary environmental objectives:

- Minimize waste and maximize resources.
- Be a good steward of the environment, while providing high-quality and reasonably priced products and services.
- Comply with or surpass all applicable environmental laws, regulations and permit requirements.

The Company maintains an executive management Sustainability Committee that supports the execution of, and makes recommendations to advance, the Company's environmental and sustainability strategy. For more information on the Company's sustainability goals, programs and performance, see the Company's Sustainability Report on its website, which is not incorporated by reference herein.

Laws & Regulations

- Air, water and solid waste pollution control
- Zoning and planning regulations - state and local authorities
- Federal and state health and safety regulations
- State facility-siting regulations

Governmental Matters The operations of the Company and certain of its subsidiaries are subject to laws and regulations relating to air, water and solid waste pollution control; state facility-siting regulations; zoning and planning regulations of certain state and local authorities; federal and state health and safety regulations; and state hazard communication standards.

The Company strives to be in substantial compliance with applicable regulations, except as to what may be ultimately determined with regard to items discussed in Environmental matters in Item 8 - Note 21. There are no pending CERCLA actions for any of the Company's material properties. However, the Company is involved in certain claims relating to the Portland, Oregon, Harbor Superfund Site and the Bremerton Gasworks Superfund Site. For more information on the Company's environmental matters, see Item 8 - Note 21 and Item 7 - MD&A - Business Section Financial and Operating Data.

Technology The Company uses technology in substantially all aspects of its business operations and requires uninterrupted operation of information technology systems and network infrastructure. These systems may be vulnerable to failures or unauthorized access. The Company has policies, procedures and processes designed to strengthen and protect these systems, which include the Company's enterprise information technology and operation technology groups continually evaluating new tools and techniques to reduce the risk and potential impacts of a cyber breach.

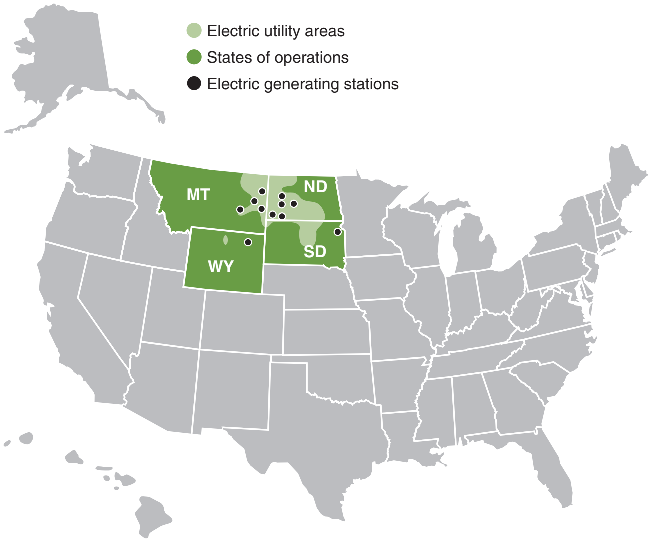
The Company created CyROC to oversee its approach to cybersecurity. CyROC is responsible for supplying management and the Audit Committee with analyses, appraisals, recommendations and pertinent information concerning cyber defense of the Company's electronic information and information technology systems. A quarterly cybersecurity report is provided to the Audit Committee. For a discussion of the Company's risks related to cybersecurity, see Item 1A - Risk Factors.

Available Information This annual report on Form 10-K, the Company's quarterly reports on Form 10-Q and current reports on Form 8-K, and any amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act are available free of charge through the Company's website as soon as reasonably practicable after the Company has electronically filed such reports with, or furnished such reports to, the SEC. The Company's website address is www.mdu.com. The information available on the Company's website is not part of this annual report on Form 10-K. The SEC also maintains a website where the Company's filings can be obtained free of charge at www.SEC.gov.

Electric

General The Company's electric segment is operated through its wholly owned subsidiary, Montana-Dakota. Montana-Dakota provides electric service at retail, serving residential, commercial, industrial and municipal customers in 185 communities and adjacent rural areas.

The material properties owned by Montana-Dakota for use in its electric operations include interests in 13 electric generating units at 11 facilities and two small portable diesel generators, as further described under System Supply, System Demand and Competition, approximately 3,400 and 4,800 miles of transmission and distribution lines, respectively, and 84 transmission and 294 distribution substations. Montana-Dakota has obtained and holds, or is in the process of renewing, valid and existing franchises authorizing it to conduct its electric operations in all of the municipalities it serves where such franchises are required. Montana-Dakota intends to protect its service area and seek renewal of all expiring franchises. At December 31, 2022, Montana-Dakota's net electric plant investment was $1.7 billion and its rate base was $1.4 billion.



Retail electric rates, service, accounting and certain securities issuances are subject to regulation by the MTPSC, NDPSC, SDPUC and WYPSC. The interstate transmission and wholesale electric power operations of Montana-Dakota are also subject to regulation by the FERC under provisions of the Federal Power Act, as are interconnections with other utilities and power generators, the issuance of certain securities, accounting, cybersecurity and other matters.

Through MISO, Montana-Dakota has access to wholesale energy, ancillary services and capacity markets for its interconnected system. MISO is a regional transmission organization responsible for operational control of the transmission systems of its members. MISO provides security center operations, tariff administration and operates day-ahead and real-time energy markets, ancillary services and capacity markets. As a member of MISO, Montana-Dakota's generation is sold into the MISO energy market and its energy needs are purchased from that market.

The retail customers served and respective revenues by class for the electric business were as follows:

	2022		2021		2020	
	Customers Served	**Revenues**	Customers Served	Revenues	Customers Served	Revenues
			(Dollars in thousands)			
Residential	**119,398**	**$ 135,412**	119,113	$ 123,043	118,893	$ 122,545
Commercial	**23,327**	**142,722**	23,149	133,336	23,050	131,207
Industrial	**230**	**42,937**	231	40,477	230	36,736
Other	**1,606**	**7,335**	1,610	6,754	1,609	6,601
	144,561	**$ 328,406**	144,103	$ 303,610	143,782	$ 297,089

Other electric revenues, which are largely transmission-related revenues, for Montana-Dakota were $48.7 million, $46.0 million and $34.9 million for the years ended December 31, 2022, 2021 and 2020, respectively.

The percentage of electric retail revenues by jurisdiction was as follows:

	2022	2021	2020
North Dakota	**65 %**	64 %	64 %
Montana	**21 %**	22 %	22 %
Wyoming	**9 %**	9 %	9 %
South Dakota	**5 %**	5 %	5 %

System Supply, System Demand and Competition Through an interconnected electric system, Montana-Dakota serves markets in portions of North Dakota, Montana and South Dakota. These markets are highly seasonal and sales volumes depend largely on the weather. Additionally, the average customer consumption has tended to decline due to increases in energy efficient lighting and appliances being installed. As of December 31, 2022, the interconnected system consisted of 12 electric generating units at 10 facilities and two small portable diesel generators. Additional details are included in the table that follows. For 2022, Montana-Dakota's total ZRCs, including its firm purchase power contracts, were 520.8. Montana-Dakota's planning reserve margin requirement within MISO was 520.2 ZRCs for 2022. The maximum electric peak demand experienced to date attributable to Montana-Dakota's sales to retail customers on the interconnected system was 611,542 kW in August 2015. Montana-Dakota's latest forecast for its interconnected system indicates that its annual peak will continue to occur during the summer. Additional energy is purchased as needed, or in lieu of generation if more economical, from the MISO market. In 2022, Montana-Dakota purchased approximately 45 percent of its net kWh needs for its interconnected system through the MISO market.

Through the Sheridan System, Montana-Dakota serves Sheridan, Wyoming, and neighboring communities. The maximum peak demand experienced to date attributable to Montana-Dakota sales to retail customers on that system was approximately 69,688 kW in August 2022. Montana-Dakota has a power supply contract with Black Hills Power, Inc. to purchase up to 49,000 kW of capacity annually through December 31, 2028. Wygen III also serves a portion of the needs of Montana-Dakota's Sheridan-area customers.

Approximately 37 percent of the electricity delivered to customers from Montana-Dakota's owned generation in 2022 was from renewable resources. Although Montana-Dakota's generation resource capacity has increased to serve the needs of its customers, the carbon dioxide emission intensity of its electric generation resource fleet has been reduced by approximately 40 percent since 2005 through the addition of renewable generation and with the retirement of aging coal-fired electric generating units, as further discussed below.

The Company ceased operations of Lewis & Clark Station in Sidney, Montana, in March 2021 and decommissioning was completed in October 2022. In February 2022, the Company ceased operations of Units 1 and 2 at Heskett Station near Mandan, North Dakota, and decommissioning commenced in July 2022. In addition, in May 2022 Montana-Dakota began construction of Heskett Unit 4, an 88-MW simple-cycle natural gas-fired combustion turbine peaking unit at the existing Heskett Station near Mandan, North Dakota, with an expected in service date in the summer of 2023.

The following table sets forth details applicable to the Company's electric generating stations:

Generating Station	Type	Fuel	Nameplate Rating (kW) at December 31, 2022	2022 ZRCs (a)	2022 Net Generation (kWh in thousands)
Interconnected System:					
North Dakota:					
Coyote (b)	Steam	Coal	103,647	94.0	571,389
Heskett (c)	Steam	Coal	—	—	47,046
Heskett	Combustion turbine	Natural gas	89,038	73.5	3,551
Glen Ullin	Renewable	Heat recovery	7,500	3.3	13,884
Cedar Hills	Renewable	Wind	19,500	3.8	64,546
Thunder Spirit	Renewable	Wind	155,500	24.6	577,567
South Dakota:					
Big Stone (b)	Steam	Coal	94,111	106.8	430,748
Montana:					
Lewis & Clark	Reciprocating internal combustion engine	Natural gas	18,700	18.0	1,539
Glendive	Combustion turbine	Natural gas / diesel	75,522	63.1	2,260
Miles City	Combustion turbine	Natural gas / diesel	23,150	18.6	583
Diamond Willow	Renewable	Wind	30,000	5.3	91,105
Portable Units (2)	Reciprocating internal combustion engine	Diesel	3,650	3.9	8
			620,318	414.9	1,804,226
Sheridan System:					
Wyoming:					
Wygen III (b)	Steam	Coal	28,000	N/A	202,487
			648,318	414.9	2,006,713

(a) Interconnected system only. MISO requires generators to obtain their summer capability through the GVTC. The GVTC is then converted to ZRCs by applying each generator's forced outage factor against its GVTC. Wind generator's ZRCs are calculated based on a wind capacity study performed annually by MISO. ZRCs are used to meet supply obligations within MISO.
(b) Reflects Montana-Dakota's ownership interest.
(c) Nameplate rating of 86,000 kW. Retired February 2022.

The owners of Coyote Station, including Montana-Dakota, have a contract with Coyote Creek for coal supply to the Coyote Station that expires December 2040. Montana-Dakota estimates the Coyote Station coal supply agreement to be approximately 1.5 million tons per contract year. For more information, see Item 8 - Note 21.

The owners of Big Stone Station, including Montana-Dakota, have a coal supply agreement with Peabody COALSALES, LLC to meet all of the Big Stone Station's fuel requirements through 2024. Montana-Dakota estimates the Big Stone Station coal supply agreement to be approximately 1.5 million tons per contract year.

Montana-Dakota has a coal supply agreement with Wyodak Resources Development Corp., to supply the coal requirements of Wygen III at contracted pricing through June 1, 2060. Montana-Dakota estimates the maximum annual coal consumption of the facility to be approximately 585,000 tons.

Montana-Dakota has entered into two purchase power agreements to purchase capacity and energy between the retirement of the Lewis & Clark Station and Heskett Station Units 1 and 2 and the completion of the new Heskett Unit 4. Montana-Dakota also purchased additional capacity and energy to cover forecasted capacity deficits through May 2026.

Montana-Dakota expects that it has secured adequate capacity available through existing baseload generating stations, renewable generation, turbine peaking stations, demand reduction programs and firm contracts to meet the peak customer demand requirements of its customers through 2030. Future capacity needs are expected to be met by constructing new generation resources or acquiring additional capacity through power purchase contracts or the MISO capacity auction.

Montana-Dakota has major interconnections with its neighboring utilities and considers these interconnections adequate for coordinated planning, emergency assistance, exchange of capacity and energy and power supply reliability.

Montana-Dakota is subject to competition resulting from customer demands, technological advances and other factors in certain areas, from rural electric cooperatives, on-site generators, co-generators and municipally owned systems. In addition, competition in varying degrees exists between electricity and alternative forms of energy such as natural gas.

Montana-Dakota is not dependent on any single customer or group of customers for sales of its products and services, where the loss of which would have a material adverse effect on its business.

Regulatory Matters and Revenues Subject to Refund In North Dakota, Montana, South Dakota and Wyoming, there are various recurring regulatory mechanisms with annual true-ups that can impact Montana-Dakota's results of operations, which also reflect monthly increases or decreases in electric fuel and purchased power costs (including demand charges). Montana-Dakota is deferring those electric fuel and purchased power costs that are greater or less than amounts presently being recovered through its existing rate schedules. Examples of these recurring mechanisms include: monthly Fuel and Purchased Power Tracking Adjustments, a fuel adjustment clause and an annual Electric Power Supply Cost Adjustment. Such mechanisms generally provide that these deferred fuel and purchased power costs are recoverable or refundable through rate adjustments which are filed annually. Montana-Dakota's results of operations reflect 95 percent of the increases or decreases from the base purchased power costs and also reflect 85 percent of the increases or decreases from the base coal price, which is also recovered through the Electric Power Supply Cost Adjustment in Wyoming. For more information on regulatory assets and liabilities, see Item 8 - Note 6.

All of Montana-Dakota's wind resources pertaining to electric operations in North Dakota are included in a renewable resource cost adjustment rider, including the North Dakota investment in Thunder Spirit. Montana-Dakota also has a transmission tracker in North Dakota to recover transmission costs associated with MISO and SPP, along with certain of the transmission investments not recovered through retail rates. The tracking mechanism has an annual true-up.

In South Dakota, Montana-Dakota recovers the South Dakota investment in Thunder Spirit through an Infrastructure Rider tracking mechanism that is subject to an annual true-up. Montana-Dakota also has in place in South Dakota a transmission tracker to recover transmission costs associated with MISO and SPP, along with certain of the transmission investments not recovered through retail rates. This tracking mechanism also has an annual true-up.

In Montana, Montana-Dakota recovers in rates, through a tracking mechanism, its allocated share of Montana property-related taxes assessed to electric operations on an after-tax basis.

For more information on regulatory matters, see Item 8 - Note 20.

Environmental Matters Montana-Dakota's electric operations are subject to federal, state and local laws and regulations providing for air, water and solid waste pollution control; state facility-siting regulations; zoning and planning regulations of certain state and local authorities; federal and state health and safety regulations; and state hazard communication standards. The electric operations strive to be in compliance with these regulations.

Montana-Dakota's electric generating facilities have Title V Operating Permits, under the federal Clean Air Act, issued by the states in which they operate. Each of these permits has a five-year life. Near the expiration of these permits, renewal applications are submitted. Permits continue in force beyond the expiration date, provided the application for renewal is submitted by the required date, usually six months prior to expiration. The WYDEQ determined all units at the Neil Simpson Complex, where Wygen III is situated, are to be included within a combined Title V Operating Permit which was submitted in June 2022. Wygen III is currently allowed to operate under the facility's construction permit until the Title V Operating Permit is issued. The Title V Operating Permit renewal application for Big Stone Station was submitted timely in October 2021 to the South Dakota Department of Agriculture & Natural Resources with the permit issuance date not specified at this time.

State water discharge permits issued under the requirements of the federal Clean Water Act are maintained for power production facilities on the Yellowstone and Missouri rivers. These permits also have five-year lives. Montana-Dakota renews these permits as necessary prior to expiration. Other permits held by these facilities may include an initial siting permit, which is typically a one-time, preconstruction permit issued by the state; state permits to dispose of combustion by-products; state authorizations to withdraw water for operations; and Army Corps permits to construct water intake structures. Montana-Dakota's Army Corps permits grant one-time permission to construct and do not require renewal. Other permit terms vary and the permits are renewed as necessary.

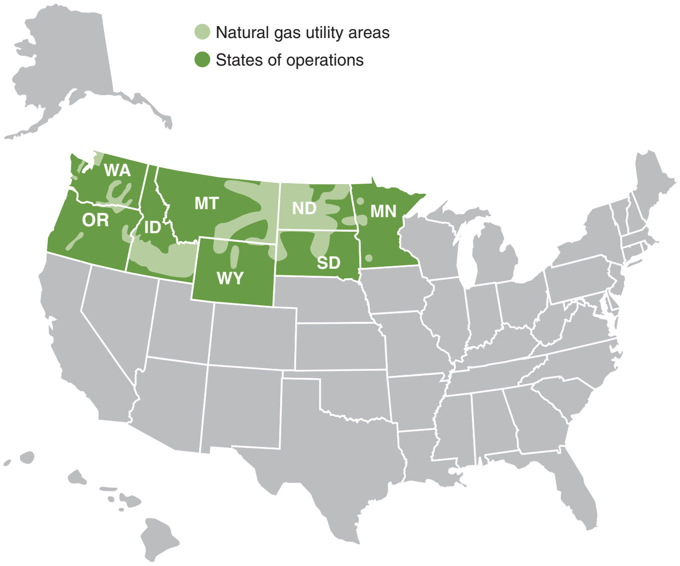
Montana-Dakota's electric operations are very small-quantity generators of hazardous waste and subject only to minimum regulation under the RCRA and when required notifies federal and state agencies of episodic generation events. Montana-Dakota routinely handles PCBs from its electric operations in accordance with federal requirements. PCB storage areas are registered with the EPA as required.

Montana-Dakota did not incur any material capital expenditures in 2022 related to compliance with current environmental laws and regulations. Environmental capital expenditures are estimated to be $3.1 million, $1.2 million and $1.0 million in 2023, 2024 and 2025, respectively, for the closure of coal ash management units at Lewis & Clark Station and Heskett Station and to maintain air emissions compliance at its co-owned electric generating facilities and does not expect to incur any material capital expenditures in 2023, 2024 or 2025 for compliance with current environmental laws and regulations. Montana-Dakota's capital and operational expenditures could also be affected by future environmental requirements, such as regional haze emission reductions. For more information, see Item 1A - Risk Factors and Item 7 - MD&A - Business Section Financial and Operating Data.

Natural Gas Distribution

General The Company's natural gas distribution segment is operated through its wholly owned subsidiaries, consisting of operations from Montana-Dakota, Cascade and Intermountain. These companies sell natural gas at retail, serving residential, commercial and industrial customers in 338 communities and adjacent rural areas across eight states. They also provide natural gas transportation services to certain customers on the Company's systems.

These services are provided through distribution and transmission systems aggregating approximately 21,300 miles and 600 miles, respectively. The natural gas distribution operations have obtained and hold, or are in the process of renewing, valid and existing franchises authorizing them to conduct their natural gas operations in all of the municipalities they serve where such franchises are required. These operations intend to seek renewal of all expiring franchises. At December 31, 2022, the natural gas distribution operations' net natural gas distribution plant investment was $2.2 billion and its rate base was $1.6 billion.



The natural gas distribution operations are subject to regulation by the IPUC, MNPUC, MTPSC, NDPSC, OPUC, SDPUC, WUTC and WYPSC regarding retail rates, service, accounting and certain securities issuances.

The retail customers served and respective revenues by class for the natural gas distribution operations were as follows:

	2022		2021		2020	
	Customers Served	**Revenues**	Customers Served	Revenues	Customers Served	Revenues
			(Dollars in thousands)			
Residential	**922,266**	**$ 715,494**	905,535	$ 548,091	887,429	$ 480,466
Commercial	**111,478**	**450,932**	110,196	330,468	108,788	281,175
Industrial	**1,077**	**41,466**	939	31,103	929	26,217
	1,034,821	**$ 1,207,892**	1,016,670	$ 909,662	997,146	$ 787,858

Transportation and other revenues for the natural gas distribution operations were $65.9 million, $62.3 million and $60.3 million for the years ended December 31, 2022, 2021 and 2020, respectively.

The percentage of the natural gas distribution operations' retail sales revenues by jurisdiction was as follows:

	2022	2021	2020
Idaho	**28 %**	27 %	30 %
Washington	**26 %**	29 %	30 %
North Dakota	**16 %**	15 %	13 %
Montana	**10 %**	10 %	8 %
Oregon	**8 %**	8 %	8 %
South Dakota	**6 %**	6 %	6 %
Minnesota	**4 %**	3 %	3 %
Wyoming	**2 %**	2 %	2 %

System Supply, System Demand and Competition The natural gas distribution operations serve retail natural gas markets, consisting principally of residential and commercial space and water heating users, in portions of Idaho, Minnesota, Montana, North Dakota, Oregon, South Dakota, Washington and Wyoming. These markets are highly seasonal and sales volumes depend largely on the weather, the effects of which are mitigated in certain jurisdictions by weather normalization mechanisms discussed later in Regulatory Matters. Additionally, the average customer consumption has tended to decline as more efficient appliances and furnaces are installed and as the Company has implemented conservation programs. In addition to the residential and commercial sales, the utilities transport natural gas for larger commercial and industrial customers who purchase their own supply of natural gas.

Competition resulting from customer demands, technological advances and other factors exists between natural gas and other fuels and forms of energy. The natural gas distribution operations have established various natural gas transportation service rates for their distribution businesses to retain interruptible commercial and industrial loads. These rates have enhanced the natural gas distribution operations' competitive posture with alternative fuels, although certain customers have bypassed the distribution systems by directly accessing transmission pipelines within close proximity. These bypasses do not have a material effect on results of operations.

The natural gas distribution operations and various distribution transportation customers obtain natural gas for their system requirements directly from producers, processors and marketers. The Company's purchased natural gas is supplied by a portfolio of contracts specifying market-based pricing and is transported under transportation agreements with WBI Energy Transmission, Northern Border Pipeline Company, Northwest Pipeline LLC, South Dakota Intrastate Pipeline, Northern Natural Gas, Gas Transmission Northwest LLC, Northwestern Energy, Viking Gas Transmission Company, Enbridge Westcoast Pipeline, Inc., Ruby Pipeline LLC, Foothills Pipe Lines Ltd., NOVA Gas Transmission Ltd, TC Energy Corporation and Northwest Natural. The natural gas distribution operations have contracts for storage services to provide gas supply during the winter heating season and to meet peak day demand with various storage providers, including WBI Energy Transmission, Dominion Energy Questar Pipeline, LLC, Northwest Pipeline LLC and Northern Natural Gas. In addition, certain of the operations have entered into natural gas supply management agreements with various parties. Demand for natural gas, which is a widely traded commodity, has historically been sensitive to seasonal heating and industrial load requirements, as well as changes in market price. The Company believes supplies are adequate for the natural gas distribution operations to meet its system natural gas requirements for the next decade. This belief is based on current and projected domestic and regional supplies of natural gas and the pipeline transmission network currently available through its suppliers and pipeline service providers.

Regulatory Matters The natural gas distribution operations' retail natural gas rate schedules contain clauses permitting adjustments in rates based upon changes in natural gas commodity, transportation and storage costs. Current tariffs allow for recovery or refunds of under- or over-recovered gas costs through rate adjustments which are filed annually.

In North Dakota and South Dakota, Montana-Dakota's natural gas tariffs contain weather normalization mechanisms applicable to certain firm customers that adjust the distribution delivery charges to reflect weather fluctuations during the November 1 through May 1 billing periods.

In Montana, Montana-Dakota recovers in rates, through a tracking mechanism, its allocated share of Montana property-related taxes assessed to natural gas operations on an after-tax basis.

In Minnesota and Washington, Great Plains and Cascade recover qualifying capital investments related to the safety and integrity of the pipeline systems through cost recovery tracking mechanisms.

In Oregon, Cascade has a decoupling mechanism in place approved by the OPUC until January 1, 2025, with a review to be completed by September 30, 2024. Cascade also has an earnings sharing mechanism with respect to its Oregon jurisdictional operations as required by the OPUC.

On July 7, 2016, the WUTC approved a full decoupling mechanism where Cascade is allowed recovery of an average revenue per customer regardless of actual consumption. The mechanism also includes an earnings sharing component if Cascade earns in excess of its authorized return. On September 15, 2021, the WUTC extended the effectiveness of the decoupling mechanism until the earlier of the rate effective date resulting from Cascade's next full general rate case or August 31, 2025.

On December 22, 2016, the MNPUC approved a request by Great Plains to implement a full revenue decoupling mechanism pilot project for three years. The decoupling mechanism reflects the period January 1 through December 31. The MNPUC adopted the administrative law judge's recommendation to extend the initial pilot period through the end of 2021. On May 13, 2022, Great Plains requested the continuation of the revenue decoupling mechanism. A final determination has not yet been made.

In Idaho, Intermountain has the authority to facilitate access for RNG producers to the Company's distribution system for the purpose of moving RNG to the producer's end-use customers.

For more information on regulatory matters, see Item 8 - Note 20.

Environmental Matters The natural gas distribution operations are subject to federal, state and local environmental, facility-siting, zoning and planning laws and regulations. The natural gas distribution operations strive to be in compliance with these regulations.

The Company's natural gas distribution operations are very small-quantity generators of hazardous waste, and subject only to minimum regulation under the RCRA. A Washington state rule defines Cascade as a small-quantity generator, but regulation under the rule is similar to RCRA. Certain locations of the natural gas distribution operations routinely handle PCBs from their natural gas operations in accordance with federal requirements. PCB storage areas are registered with the EPA as required. Capital and operational expenditures for natural gas distribution operations could be affected in a variety of ways by potential new GHG legislation or regulation. In particular, such legislation or regulation would likely increase capital expenditures for energy efficiency and conservation programs and operational and gas supply costs associated with GHG emissions compliance. Natural gas distribution operations expect to recover the operational and capital expenditures for GHG regulatory compliance in rates consistent with the recovery of other reasonable costs of complying with environmental laws and regulations. For more information, see Item 7 - MD&A - Business Section Financial and Operating Data.

The natural gas distribution operations did not incur any material capital expenditures in 2022 related to compliance with current environmental laws and regulations. However, Cascade does expect to incur capital expenditures for compliance with the Oregon Climate Protection Program and Washington Climate Commitment Act, which are estimated to be $4.3 million, $19.1 million and $2.6 million, respectively, in 2023, 2024 and 2025. The capital expenditures are for the development and construction of a renewable natural gas facility at the Deschutes County Landfill near Bend, Oregon. Except as to what may be ultimately determined with regard to the issues described in the following paragraph and the items noted for Cascade, the natural gas distribution operations do not expect to incur any material capital expenditures related to compliance with current environmental laws and regulations through 2025.

Montana-Dakota has ties to six historic manufactured gas plants as a successor corporation or through direct ownership of the plant. Montana-Dakota is investigating possible soil and groundwater impacts due to the operation of two of these former manufactured gas plant sites. To the extent not covered by insurance, Montana-Dakota may seek recovery in its natural gas rates charged to customers for certain investigation and remediation costs incurred for these sites. Cascade has ties to nine historic manufactured gas plants as a successor corporation or through direct ownership of the plant. Cascade is involved in the investigation and remediation of one of these manufactured gas plants in Washington. To the extent not covered by insurance, Cascade will seek recovery of investigation and remediation costs through its natural gas rates charged to customers.

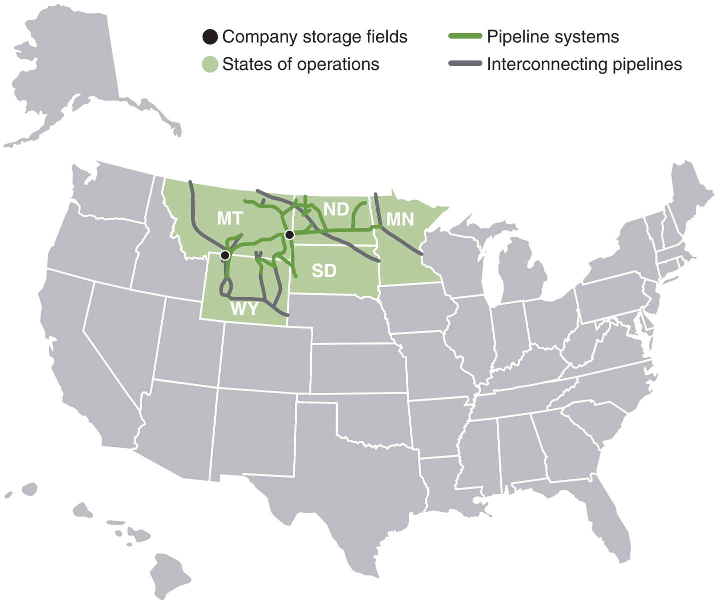
See Item 8 - Note 21 for further discussion of certain manufactured gas plant sites.

Pipeline

General WBI Energy owns and operates both regulated and non-regulated businesses. The regulated business of this segment, WBI Energy Transmission, owns and operates approximately 3,800 miles of natural gas transmission and storage lines.

WBI Energy Transmission's underground storage fields provide storage services to local distribution companies, industrial customers, natural gas marketers and others, and serve to enhance system reliability. Its system is strategically located near four natural gas producing basins, making natural gas supplies available to its transportation and storage customers. The system has 14 interconnecting points with other pipeline facilities allowing for the receipt and/or delivery of natural gas to and from other regions of the country and from Canada. Under the Natural Gas Act, as amended, WBI Energy Transmission is subject to the jurisdiction of the FERC regarding certificate, rate, service and accounting matters, and at December 31, 2022, its net plant investment was $798.1 million.

The non-regulated business of this segment provides a variety of energy-related services, including cathodic protection and energy efficiency product sales and installation services to large end-users.



A majority of the pipeline business is transacted in the Rocky Mountain and northern Great Plains regions of the United States.

System Supply, System Demand and Competition Natural gas supplies emanate from traditional and nontraditional production activities in the region from both on-system and off-system supply sources. Incremental supply from nontraditional sources, such as the Bakken area in Montana and North Dakota, have helped offset declines in traditional regional supply sources and supports WBI Energy Transmission's transportation and storage services. In addition, off-system supply sources are available through the Company's interconnections with other pipeline systems. WBI Energy Transmission continues to look for opportunities, such as the identified growth projects discussed in Item 7 - MD&A - Pipeline Outlook, to increase transportation and storage services through system expansion and/or other pipeline interconnections or enhancements that could provide future benefits.

WBI Energy Transmission's underground natural gas storage facilities have a certificated storage capacity of approximately 350 Bcf, including 193 Bcf of working gas capacity, 83 Bcf of cushion gas and 74 Bcf of native gas. These storage facilities enable customers to purchase natural gas throughout the year and meet winter peak requirements.

WBI Energy Transmission competes with several pipelines for its customers' transportation business and at times may discount rates in an effort to retain market share; however, the strategic location of its system near four natural gas producing basins and the availability of underground storage services, along with interconnections with other pipelines, enhances its competitive position.

Although certain of WBI Energy Transmission's firm customers, including its largest firm customer Montana-Dakota, serve relatively secure residential, commercial and industrial end-users, they generally all have some price-sensitive end-users that could switch to alternate fuels.

WBI Energy Transmission transports substantially all of Montana-Dakota's natural gas, primarily utilizing firm transportation agreements, which for 2022 represented 22 percent of WBI Energy Transmission's subscribed firm transportation contract demand. The majority of the firm transportation agreements with Montana-Dakota expire in June 2027. In addition, Montana-Dakota has a contract, expiring in July 2035, with WBI Energy Transmission to provide firm storage services to facilitate meeting Montana-Dakota's winter peak requirements.

The non-regulated business of this segment competes for existing customers in the areas in which it operates. Its focus on customer service and the variety of services it offers serve to enhance its competitive position.

WBI Energy is not dependent on any single customer or group of customers for sales of its products and services, where the loss of which would have a material adverse effect on its business. WBI Energy had one third-party customer that accounted for approximately 11% of its 2022 revenue.

Environmental Matters The pipeline operations are subject to federal, state and local environmental, facility-siting, zoning and planning laws and regulations.

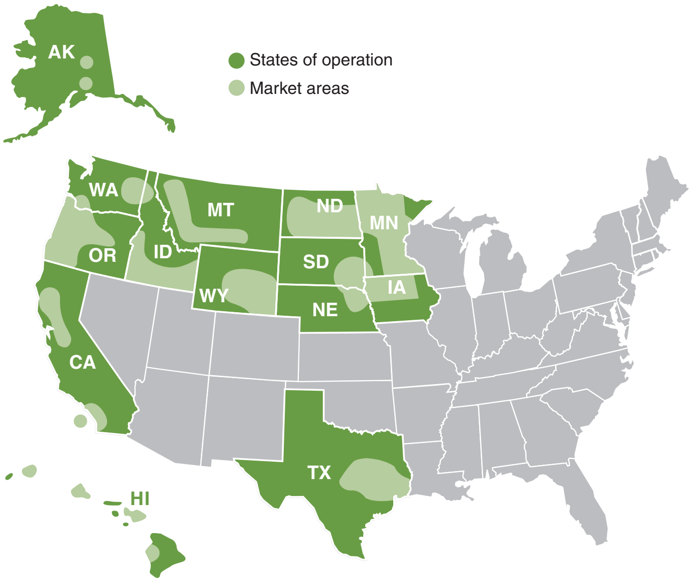
Administration of certain provisions of federal environmental laws is delegated to the states where WBI Energy and its subsidiaries operate. Administering agencies may issue permits with varying terms and operational compliance conditions. Permits are renewed and modified, as necessary, based on defined permit expiration dates, operational demand, facility upgrades or modifications, and/or regulatory changes. The pipeline operations strive to be in compliance with these regulations.

Detailed environmental assessments and/or environmental impact statements as required by the National Environmental Policy Act are included in the FERC's environmental review process for both the construction and abandonment of WBI Energy Transmission's natural gas transmission pipelines, compressor stations and storage facilities.

The EPA recently proposed additional rules to update, strengthen and expand standards intended to significantly reduce GHG emissions and other air pollutants from the oil and natural gas industries. The standards will apply to natural gas compressors, pneumatic controllers and pumps, fugitive emissions components and super-emitter events. The EPA projects the final rules will be issued in August 2023. Additionally, the EPA anticipates revising the current GHG reporting rules to incorporate provisions in the IRA. These revisions are anticipated to be issued in April 2023. The Company continues to monitor and assess the proposed rules and the potential impacts they may have on its business processes, current and future projects, results of operations and disclosures.

The pipeline operations did not incur any material capital expenditures related to compliance with current environmental laws and regulations in 2022 and do not expect to incur any material capital expenditures related to compliance with current environmental laws and regulations through 2025. Expected or anticipated rules are not included in the capital expenditures for 2023 to 2025. For more information on the capital expenditures for this segment, see Item 7 - MD&A - Capital Expenditures.

Construction Materials and Contracting



General Knife River mines, processes and sells construction aggregates (crushed stone and sand and gravel); produces and sells asphalt; and supplies ready-mix concrete. These products are used in most types of construction, performed by Knife River and other companies, including roads, freeways and bridges, as well as homes, schools, shopping centers, office buildings and industrial parks. Knife River's aggregate reserves provide the foundation for the vertical integration of its contracting services with its construction materials to support its aggregate-based product lines including heavy-civil construction, asphalt paving, concrete construction and site development and grading. Although not common to all locations, the segment also includes the sale of cement, liquid asphalt modification and distribution, various finished concrete products, merchandise and other building materials and related contracting services.

Through its network of aggregate sites, ready-mix plants and asphalt plants, the Company supplies construction materials and contracting services to public and private customers in 14 states.

Competition Knife River's construction materials products and contracting services are marketed under competitive conditions. Price is the principal competitive force to which these products and services are subject, with service, quality, delivery time and proximity to the customer as well as technical expertise, safety ratings, financial and operational resources and industry reputation around dependability also being significant factors. Knife River focuses on markets located near aggregate sites to reduce transportation costs which allows Knife River to remain competitive with the pricing of aggregate products. The number and size of competitors varies in each of Knife River's principal market areas and product lines.

The demand for construction materials products and contracting services is significantly influenced by the cyclical nature of the construction industry. In addition, activity in certain locations may be seasonal in nature due to the effects of weather. The key economic factors affecting product demand are changes in the level of local, state and federal governmental spending on roads and infrastructure projects, general economic conditions within the market area that influence the commercial and residential sectors, and prevailing interest rates.

Knife River's customers are a diverse group which includes federal, state and municipal governmental agencies, industrial, commercial and residential developers, and other private parties. The mix of sales by customer class varies each year depending on the fluctuation of work. Knife River is not dependent on any single customer or group of customers for sales of its products and services, the loss of which would have a material adverse effect on its construction materials businesses. No individual customer accounted for more than 10% of its 2022 revenue.

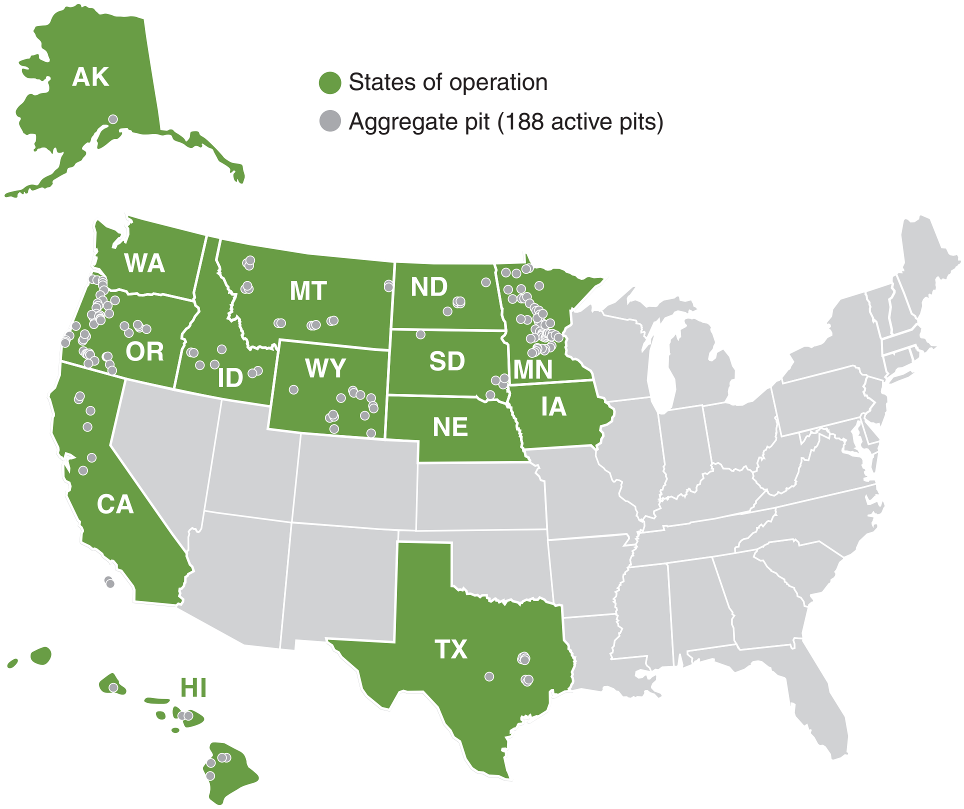
Reserve Information Knife River mines crushed stone and sand and gravel at its 188 active aggregate sites. The aggregates produced by Knife River are utilized in general construction and are a major component in the production of ready-mix concrete and asphalt.

Aggregate reserve and resource estimates are calculated based on available data. Supporting data includes, but is not limited to, drill holes, geologic testing and other subsurface investigations; and surface feature investigations, such as, mine high walls, aerial photography, topography, and other data. Using available data, a final topography map is created with computer software and is used to calculate the volume variance between existing and final topographies. Volumes are then converted to tons using appropriate conversion factors. Property setbacks and other regulatory restrictions and limitations are identified to determine the total area available for mining. Knife River also considers mine plans, economic viability and production history in the aggregate reserve and resource estimates. Mineral reserves are defined as an estimate of tonnage that, in the opinion of the qualified person, can be economically mined or extracted, which includes diluting materials and allowances for losses that may occur throughout the process. Mineral resources are defined as a concentration or occurrence of material of economic interest in such form, grade or quality, and quantity that has a reasonable prospect to be economically extracted. Knife River's reserve estimates include only salable tonnage and thus exclude waste materials that are generated in the crushing and processing phases of the operation. The reserves are based on estimates of volumes that can be economically extracted and sold to meet current market and product applications.

Knife River's reserves and resources are on properties that are permitted, or are expected to be permitted, for mining under current regulatory requirements. The data used to calculate reserves and resource estimates may require revisions in the future to account for changes in customer requirements and unknown geological occurrences.

Knife River classifies the applicable quantity of a particular deposit as a reserve or resource by reviewing and analyzing, independently, each geological formation, testing results and production processes, along with other modifying factors, to determine an expected yield of recoverable tonnage an area will produce. These results may have an effect on mine plans and the selection of processing equipment. The results are reviewed by the qualified person and presented to the management team.

Management assesses the risks associated with aggregate reserve and resource estimates. These estimates may be affected by variability in the properties of the material, limits of the accuracy of the geotechnical data and operational difficulties in extraction of the computed material. Additionally, management assesses the risks associated in obtaining and maintaining the various land use, mining and environmental permits necessary for the properties to operate as mines. Annual reviews of mining reserves are conducted by the qualified person and include procedures such as ensuring financial assumptions related to life of mine expenses are based on the most accurate estimates available.



Knife River has reviewed its properties and has determined it does not have any individual sites that are material. The following table sets forth details applicable to Knife River's aggregate production and aggregate sites as of December 31, 2022.

	Total Annual Aggregate Production		Aggregate Sites			
Production Area	Crushed Stone	Sand & Gravel	Crushed Stone		Sand & Gravel	
	(Tons in thousands)		Owned	Leased	Owned	Leased
Alaska	—	1,041	—	—	1	—
California	377	1,665	—	2	8	1
Hawaii	1,470	—	—	5	—	—
Idaho	5	2,339	—	1	6	3
Minnesota	375	2,410	3	1	48	8
Montana	—	3,043	—	—	11	2
North Dakota	—	897	—	—	3	12
Oregon	6,882	4,017	11	12	19	9
South Dakota	1,878	2,226	2	—	1	3
Texas	1,181	167	4	1	1	—
Wyoming	1,166	1,043	2	6	1	4
	13,334	18,848	22	28	99	42

The following table sets forth details applicable to Knife River's aggregate reserves as of December 31, 2022.

		Crushed Stone			Sand & Gravel			
Production Area	Aggregate Sites	Proven Mineral Reserves	Probable Mineral Reserves	**Total Mineral Reserves**	Proven Mineral Reserves	Probable Mineral Reserves	**Total Mineral Reserves**	**Total Mineral Reserves**
				(Tons in thousands)				
Alaska	1	—	—	**—**	12,542	—	**12,542**	**12,542**
California	10	89,913	—	**89,913**	19,070	—	**19,070**	**108,983**
Hawaii	5	42,964	662	**43,626**	—	—	**—**	**43,626**
Idaho	10	230	—	**230**	22,689	10,914	**33,603**	**33,833**
Minnesota	60	15,853	—	**15,853**	45,883	13,301	**59,184**	**75,037**
Montana	13	—	—	**—**	60,980	9,950	**70,930**	**70,930**
North Dakota	15	—	—	**—**	20,379	1,999	**22,378**	**22,378**
Oregon	49	361,217	14,046	**375,263**	118,209	13,477	**131,686**	**506,949**
South Dakota	6	29,706	3,000	**32,706**	3,284	—	**3,284**	**35,990**
Texas	6	65,451	4,691	**70,142**	8,368	—	**8,368**	**78,510**
Wyoming	13	76,895	11,582	**88,477**	14,513	14,197	**28,710**	**117,187**
	188	682,229	33,981	**716,210**	325,917	63,838	**389,755**	**1,105,965**

* The average selling price per ton for crushed stone and sand and gravel was $16.12 and $10.53, respectively, in 2022.

** The aggregates mined are of suitable grade and quality to be used as construction materials and no further grade or quality disclosure is applicable.

The following table sets forth details applicable to Knife River's aggregate resources as of December 31, 2022.

		Sand & Gravel			
Production Area	Aggregate Sites	Measured Mineral Resources	Indicated Mineral Resources	**Measured + Indicated Mineral Resources**	Inferred Mineral Resources
			(Tons in thousands)		
California	1	14,673	—	**14,673**	—
Minnesota	—	—	—	**—**	373
Montana	—	11,500	—	**11,500**	—
Oregon	2	41,727	—	**41,727**	—
	3	67,900	—	**67,900**	373

* Minnesota and Montana each have a site that includes both reserves and resources, which are included in the aggregate sites for reserves.

Of Knife River's 191 properties, 139 are in a production stage, 49 in a development stage and three are classified as exploration stage properties. As of December 31, 2022, Knife River had 1.1 billion tons of estimated proven and probable reserves of which 939 million tons are located on production stage properties and 167 million tons on developmental stage properties. The Company classifies aggregates located on exploration stage properties as resources. Knife River's aggregate annual production in tons for all its mining properties was 32.2 million, 31.1 million and 28.5 million for the years ended December 31, 2022, 2021 and 2020, respectively.

The average selling price per ton for crushed stone and sand and gravel was $16.12 and $10.53, respectively, in 2022. Actual pricing varies by location and market. The price for each commodity was calculated by dividing 2022 revenues by tons sold. The average pricing is based on salable product, or materials that are ready for sale. Pricing for aggregates tends to remain similar for long periods of time and resources generally realize similar pricing to reserves when extracted and sold; therefore, Knife River uses current pricing as an estimate of future pricing. Pricing is assessed frequently to verify there have been no material changes. Knife River expects future sales prices to exceed future production costs, resulting in minimal change to the economic viability of the disclosed reserves and resources. Knife River believes the current sales price is reasonable and justifiable to estimate the aggregates' current fair value, while the balance sheet reflects the historical costs.

Knife River owns 121 properties, of which 118 are active sites, and leases another 70 to conduct its mining operations. Its reserves are comprised of 566 million tons on properties that are owned and 540 million tons that are leased. The remaining reserve life in years was calculated by dividing remaining reserves by the three-year average production from 2020 through 2022. Knife River estimates the useful life of its owned reserves are approximately 36 years based on the most recent three-year average production. Approximately 47 percent of the reserves under lease have lease expiration dates of 20 years or more and the weighted average years remaining on all leases containing estimated proven aggregate reserves is approximately 21 years, including options for renewal that are at Knife River's discretion. The average time necessary to produce remaining aggregate reserves from its leased sites is approximately 42 years. Some sites have leases that expire prior to the exhaustion of the estimated reserves. The estimated reserve life assumes, based on Knife River’s experience, that leases will be renewed to allow sufficient time to fully recover these reserves. Actual useful lives of these reserves will be subject to, among other things, fluctuations in customer demand, customer specifications, geological conditions and changes in mining plans.

Internal Controls Over Aggregate Reserves

Reserve and resource estimates are based on the analyses of available data by qualified internal mining engineers, operating personnel and third-party geologists. Senior management reviews and approves reserve and resource quantity estimates and reserve classifications, including the major assumptions used in determining the estimates, such as life, pricing, cost and volume, among other things, to ensure they are materially accurate. For aggregate reserve and resource additions, management, which includes the qualified person, performs its due diligence and reviews the study of technical, economic and operating factors, as well as applicable supplemental information, including a summary of the site's geotechnical report. Knife River maintains a database of all aggregate reserves, which is reconciled at least annually and reviewed and approved by the qualified person.

The evaluation, classification and estimation of reserves has inherent risks, including changing geotechnical, market and permitting conditions. The qualified person and management work together to assess these risks regularly and amend the reserve and resource assessments as new information becomes available.

Environmental Matters Knife River's construction materials and contracting operations are subject to regulation customary for such operations, including federal, state and local environmental compliance and reclamation regulations. Knife River strives to be in compliance with these regulations. Individual permits applicable to Knife River's various operations are managed and tracked as they relate to the statuses of the application, modification, renewal, compliance and reporting procedures.

Knife River's asphalt and ready-mix concrete manufacturing plants and aggregate processing plants are subject to the federal Clean Air Act and the federal Clean Water Act requirements for controlling air emissions and water discharges. Some mining and construction activities are also subject to these laws. In most of the states where Knife River operates, these regulatory programs are delegated to state and local regulatory authorities. Knife River's facilities are also subject to the RCRA as it applies to the management of hazardous wastes and underground storage tank systems. These programs are generally delegated to the state and local authorities in the states where Knife River operates. Knife River's facilities must comply with requirements for managing wastes and underground storage tank systems.

Certain activities of Knife River are directly regulated by federal agencies. For example, certain in-water mining operations are subject to provisions of the federal Clean Water Act that are administered by the Army Corps. Knife River has several such operations, including gravel bar skimming and dredging operations, and Knife River has the associated required permits. The expiration dates of these permits vary, with five years generally being the longest term.

Knife River's operations are also occasionally subject to the ESA. For example, land use regulations often require environmental studies, including wildlife studies, before a permit may be granted for a new or expanded mining facility or an asphalt or concrete plant. If endangered species or their habitats are identified, ESA requirements for protection, mitigation or avoidance apply. Endangered species protection requirements are usually included as part of land use permit conditions. Typical conditions include avoidance, setbacks, restrictions on operations during certain times of the breeding or rearing season, and construction or purchase of mitigation habitat. Knife River's operations are also subject to state and federal cultural resource protection laws when new areas are disturbed for mining operations or processing plants. Land use permit applications generally require that areas proposed for mining or other surface disturbances be surveyed for cultural resources. If any are identified, they must be protected or managed in accordance with regulatory agency requirements.

The most comprehensive environmental permit requirements are usually associated with new mining operations, although requirements vary widely from state to state and even within states. In some areas, land use regulations and associated permitting requirements are minimal. However, some states and local jurisdictions have very demanding requirements for permitting new mines. Environmental impact reports are sometimes required before a mining permit application can be considered for approval. These reports can take up to several years to complete. The report can include projected impacts of the proposed project on air and water quality, wildlife, noise levels, traffic, scenic vistas and other environmental factors. The reports generally include suggested actions to mitigate the projected adverse impacts.

Provisions for public hearings and public comments are usually included in land use permit application review procedures in the counties where Knife River operates. After considering environmental, mine plan and reclamation information provided by the permittee, as well as comments from the public and other regulatory agencies, the local authority approves or denies the permit application. Denial is rare, but land use permits often include conditions that must be addressed by the permittee. Conditions may include property line setbacks, reclamation requirements, environmental monitoring and reporting, operating hour restrictions, financial guarantees for reclamation, and other requirements intended to protect the environment or address concerns submitted by the public or other regulatory agencies.

Knife River has been successful in obtaining mining and other land use permits so sufficient permitted reserves are available to support its operations. For mining operations, this often requires considerable advanced planning to ensure sufficient time is available to complete the permitting process before the newly permitted aggregate reserve is needed to support Knife River's operations.

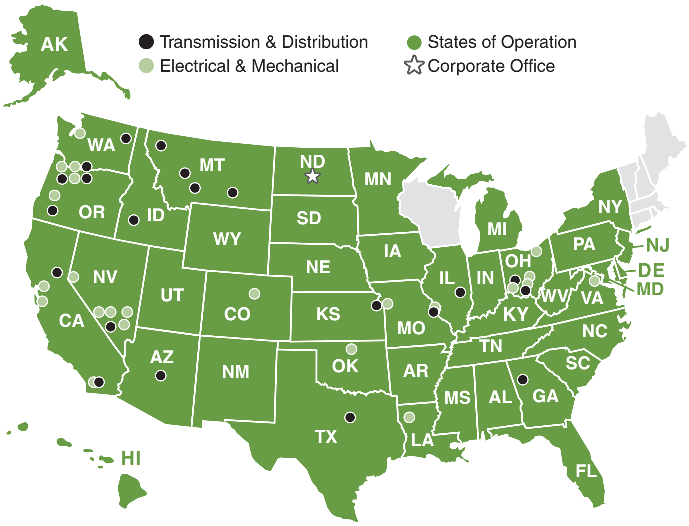
Knife River's Gascoyne surface coal mine last produced coal in 1995 but continues to be subject to reclamation requirements of the Surface Mining Control and Reclamation Act, as well as the North Dakota Surface Mining Act. Portions of the Gascoyne Mine remain under reclamation bond until the 10-year revegetation liability period has expired. A portion of the original permit has been released from bond and additional areas are currently in the process of having the bond released. Knife River intends to request bond release as soon as it is deemed possible.

Knife River did not incur any material capital expenditures in 2022 related to compliance with current environmental laws and regulations and, except as to what may be ultimately determined with regard to the issues described in the following paragraph, Knife River does not expect to incur any material capital expenditures related to compliance with current environmental laws and regulations through 2025.

In December 2000, Knife River - Northwest was named by the EPA as a PRP in connection with the cleanup of a commercial property site, acquired by Knife River - Northwest in 1999, and part of the Portland, Oregon, Harbor Superfund Site. For more information, see Item 8 - Note 21.

Mine Safety The Dodd-Frank Act requires disclosure of certain mine safety information. For more information, see Item 4 - Mine Safety Disclosures.

Construction Services



General MDU Construction Services operates in nearly every state across the country and provides a full spectrum of construction services through its electrical and mechanical and transmission and distribution specialty contracting services across the United States. These specialty contracting services are provided to utilities, manufacturing, transportation, commercial, industrial, institutional, renewable and governmental customers. Its electrical and mechanical contracting services include construction and maintenance of electrical and communication wiring and infrastructure, fire suppression systems, and mechanical piping and services. Its transmission and distribution contracting services include construction and maintenance of overhead and underground electrical, gas and communication infrastructure, as well as manufacturing and distribution of transmission line construction equipment and tools.

Construction and maintenance crews are active year round. However, activity in certain locations may be seasonal in nature due to the effects of weather. MDU Construction Services works with the National Electrical Contractors Association, the IBEW and other trade associations on hiring and recruiting a qualified workforce.

MDU Construction Services operates a fleet of owned and leased trucks and trailers, support vehicles and specialty construction equipment, such as backhoes, excavators, trenchers, generators, boring machines and cranes. In addition, as of December 31, 2022, MDU Construction Services owned or leased facilities in 19 states. This space is used for offices, equipment yards, manufacturing, warehousing, storage and vehicle shops.

Competition MDU Construction Services operates in a highly competitive business environment. Most of MDU Construction Services' work is obtained on the basis of competitive bids or by negotiation of either cost-plus or fixed-price contracts. Its workforce and equipment are highly mobile, providing greater flexibility in the size and location of MDU Construction Services' market area. Competition is based primarily on price and reputation for quality, safety and reliability. The size and location of the services provided, as well as the state of the economy, are factors in the number of competitors that MDU Construction Services will encounter on any particular project. MDU Construction Services believes the diversification of the services it provides, the markets it serves in the United States and the quality and management of its workforce enable it to effectively operate in this competitive environment.

Utilities and independent contractors represent the largest customer base for this segment. Accordingly, utility and subcontract work accounts for a significant portion of the work performed by MDU Construction Services and the amount of construction contracts is dependent on the level and timing of maintenance and construction programs undertaken by customers. MDU Construction Services benefits from repeat customers and strives to maintain successful long-term relationships with its customers. The mix of sales by customer class varies each year depending on available work. MDU Construction Services is not dependent on any single customer or group of customers for sales of its products and services, the loss of which would have a material adverse effect on its business. MDU Construction Services had one customer that accounted for approximately 15% of its revenue for 2022.

Environmental Matters MDU Construction Services' operations are subject to regulation customary for the industry, including federal, state and local environmental compliance. MDU Construction Services strives to be in compliance with these regulations.

The nature of MDU Construction Services' operations is such that few, if any, environmental permits are required. Operational convenience supports the use of petroleum storage tanks in several locations, which are permitted under state programs authorized by the EPA. MDU Construction Services has no ongoing remediation related to releases from petroleum storage tanks. MDU Construction Services' operations are conditionally exempt small-quantity waste generators, subject to minimal regulation under the RCRA. Federal permits for specific construction and maintenance jobs that may require these permits are typically obtained by the hiring entity, and not by MDU Construction Services.

MDU Construction Services did not incur any material capital expenditures in 2022 related to compliance with current environmental laws and regulations and does not expect to incur any material capital expenditures related to compliance with current environmental laws and regulations through 2025.

Item 1A. Risk Factors

The Company's business and financial results are subject to a number of risks and uncertainties, including those set forth below and in other documents filed with the SEC. The factors and other matters discussed herein are important factors that could cause actual results or outcomes for the Company to differ materially from those discussed in the forward-looking statements included elsewhere in this document. If any of the risks described below actually occur, the Company's business, prospects, financial condition or financial results could be materially harmed. The following are the most material risk factors applicable to the Company and are not necessarily listed in order of importance or probability of occurrence.

Separation Risks

The proposed separation of Knife River Holding Company into an independent, publicly traded company is subject to various risks and uncertainties, and may not be completed on the terms or timeline currently contemplated, if at all.

On August 4, 2022, the Company announced its plan to separate Knife River Holding Company, the construction materials and contracting business, from the Company, which would result in two independent, publicly traded companies. The execution of the proposed separation has required and will continue to require significant time and attention from the Company’s senior management and employees, which could disrupt the Company’s ongoing business and adversely affect financial results and results of operations. Further, the Company's employees may be distracted due to the uncertainty regarding their future roles with the Company or Knife River Holding Company pending the consummation of the proposed separation. Additionally, foreseen and unforeseen costs may be incurred in connection with the proposed separation, including fees such as advisory, accounting, tax, legal, reorganization, debt breakage, restructuring, severance/employee benefit-related, regulatory, SEC filing and other professional services, some of which may be incurred regardless if the separation occurs. The proposed separation is also complex, and completion of the proposed separation and the timing of its completion will be subject to a number of factors and conditions, including the readiness of the new company to operate as an independent public company and finalization of the capital structure of the new company. Unanticipated developments could delay, prevent or otherwise adversely affect the proposed separation, including, but not limited to, changes in general economic and financial market conditions, material adverse changes in business or industry conditions, unanticipated costs and potential problems or delays in obtaining various regulatory and tax approvals or clearances. In particular, changes in interest or exchange rates and the effects of inflation could delay or adversely affect the proposed separation, including in connection with any debt financing transactions undertaken in connection with the separation or the terms of any indebtedness incurred in connection therewith. There can be no assurances that the Company will be able to complete the proposed separation on the terms or on the timeline that was announced, if at all.

If the distribution, together with certain related transactions, does not qualify as a transaction that is generally tax-free for U.S. federal income tax purposes, the Company and its stockholders could be subject to significant tax liabilities.

The Company is seeking a private letter ruling from the IRS and opinion(s) of its tax advisors, regarding certain U.S. federal income tax matters relating to the separation and the distribution, including, with respect to the opinion(s), to the effect that the distribution will be a transaction described in Section 355(a) of the Code. The IRS private letter ruling and the opinion(s) of tax advisors will be based upon and rely on, among other things, various facts and assumptions, as well as certain representations, statements and undertakings of the Company, including those relating to the past and future conduct of the Company. If any of these representations, statements or undertakings is, or becomes, inaccurate or incomplete, or if the Company should breach any of the representations or covenants contained in any of the separation-related agreements and documents or in any documents relating to the IRS private letter ruling and/or the opinion(s) of tax advisors, the IRS private letter ruling and/or the opinion(s) of tax advisors may be invalid and the conclusions reached therein could be jeopardized.

Notwithstanding receipt of the IRS private letter ruling and the opinion(s) of tax advisors, the IRS could determine that the distribution and/or certain related transactions should be treated as taxable transactions for U.S. federal income tax purposes if it determines that any of the representations, assumptions, or undertakings upon which the IRS private letter ruling or the opinion(s) of tax advisors were based are false or have been violated. In addition, neither the IRS private letter ruling nor the opinion(s) of tax advisors will address all of the issues that are relevant to determining whether the distribution, together with certain related transactions, qualifies as a transaction that is generally tax-free for U.S. federal income tax purposes. Further, the opinion(s) of tax advisors represent the judgment of such tax advisors and are not binding on the IRS or any court, and the IRS or a court may disagree with the conclusions in the opinion(s) of tax advisors. Accordingly, notwithstanding receipt by the Company of the IRS private letter ruling and the opinion(s) of tax advisors, there can be no assurance that the IRS will not assert that the distribution and/or certain related transactions do not qualify for tax-free treatment for U.S. federal income tax purposes or that a court would not sustain such a challenge. In the event the IRS were to prevail in such challenge, the Company and its stockholders could be subject to significant U.S. federal income tax liability.

If the distribution, together with related transactions, fails to qualify as a transaction that is generally tax-free for U.S. federal income tax purposes under Sections 355 and 368(a)(1)(D) of the Code, in general, for U.S. federal income tax purposes, the Company would recognize taxable gain as if it had sold Knife River Holding Company common stock in a taxable sale for its fair market value (unless the Company and Knife River Holding Company jointly make an election under Section 336(e) of the Code with respect to the distribution, in which case, in general, (a) the Company would recognize a taxable gain as if Knife River Holding Company had sold all of its assets in a taxable sale in exchange for an amount equal to the fair market value of Knife River Holding Company common stock and the assumption of all of its liabilities and (b) Knife River Holding Company would obtain a related step-up in the basis of its assets) and, if the distribution fails to qualify as a transaction that is generally tax-free for U.S. federal income tax purposes under Section 355, the Company's stockholders who receive Knife River Holding Company shares in the distribution would be subject to tax as if they had received a taxable distribution equal to the fair market value of such shares.

The Company may not achieve some or all of the expected benefits of the separation, and the separation may materially and adversely affect its financial position, results of operations and cash flows.

The Company may be unable to achieve the full strategic and financial benefits expected to result from the separation, or such benefits may be delayed or not occur at all. The separation and distribution are expected to provide the following benefits, among others:

- A distinct investment identity allowing investors to evaluate the merits, strategy, performance and future prospects of the Company's regulated energy delivery business and Knife River Holding Company's aggregates-based construction materials and contracting services business.
- Enhanced strategic focus to more effectively pursue individualized strategies specific to the industries in which each operates and use equity tailored to its own business to enhance acquisition and capital programs.
- More efficient allocation of capital for both the Company and Knife River Holding Company based on each company's profitability, cash flow and growth opportunities.
- Creating an independent equity structure that will facilitate the Company's and Knife River Holding Company's ability to deploy capital toward its specific growth opportunities.
- Enhanced employee hiring and retention by, among other things, improving the alignment of management and employee incentives with industry specific performance and growth objectives.

The Company may not achieve these and/or other anticipated benefits for a variety of reasons, including, among others, that: (a) the separation will require significant time and effort from management, which may divert management's attention from operating and growing the business; (b) following the separation and distribution, the Company may be more susceptible to stock market fluctuations and other adverse events; (c) following the separation and distribution, the Company may not be able to maintain its historical practices with respect to dividends; (d) following the separation and distribution, the Company's business will be less diversified than prior to the separation and distribution; and (e) the other actions required to separate the Company and Knife River Holding Company's respective businesses could disrupt their operations. If the Company fails to achieve some or all of the benefits expected to result from the separation, or if such benefits are delayed, it could have a material adverse effect on its financial position, results of operations and cash flows.

The Company may fail to perform under various transaction agreements that are expected be executed as part of the separation. The Company's inability to favorably resolve any disputes that arise with Knife River Holding Company with respect to their various past and ongoing relationships may adversely affect the Company's operating results.

In connection with the separation and prior to the distribution, it is anticipated that the Company will enter into a separation agreement and will also enter into various other agreements, including a transition services agreement, a tax matters agreement and an employee matters agreement with Knife River Holding Company. The separation agreement, the tax matters agreement and the employee matters agreement will determine the allocation of assets and liabilities between the companies following the separation for those respective areas and will include any necessary indemnifications related to liabilities and obligations. The transition services agreement will provide for the performance of certain services by the Company for the benefit of Knife River Holding Company, or in some cases certain services provided by Knife River Holding Company for the benefit of the Company, for a limited period of time after the separation. Knife River Holding Company will rely on the Company to satisfy its obligations under these agreements. If the Company is unable to satisfy its obligations under these agreements, including its indemnification obligations, the Company could be subject to disputes.

The Company may not be able to resolve potential conflicts, and even if it does, the resolution may be less favorable than if it were dealing with an unaffiliated party. Disputes may arise between the Company and Knife River Holding Company in a number of areas relating to the various transaction agreements, including, among other things:

- Labor, tax, employee benefit, indemnification and other matters arising from Knife River Holding Company's separation from the Company.
- Employee retention and recruiting.
- Business combinations involving Knife River Holding Company.
- And the nature, quality and pricing of services that the Company has agreed to provide.

If the expected separation and distribution occurs, certain members of management, directors and stockholders will hold stock in both the Company and Knife River Holding Company, and as a result may face actual or potential conflicts of interest.
If the separation and distribution occurs, the management and directors of each of the Company and Knife River Holding Company may own both the Company common stock and Knife River Holding Company common stock. This ownership overlap could create, or appear to create, potential conflicts of interest when the Company's management and directors and Knife River Holding Company's management and directors face decisions that could have different implications for the Company and Knife River Holding Company. For example, potential conflicts of interest could arise in connection with the resolution of any dispute between the Company and Knife River Holding Company regarding the terms of the agreements governing the distribution and the relationship between the Company thereafter and Knife River Holding Company. These agreements include the separation and distribution agreement, the tax matters agreement, the employee matters agreement, the transition services agreement, the stockholder and registration rights agreement and any commercial agreements between the parties or their affiliates. Potential conflicts of interest may also arise out of any commercial arrangements that the Company or Knife River Holding Company may enter into in the future.

Following the separation, there may be a substantial change in the Company's stockholder base and its stock price may fluctuate significantly.
Until the market has fully evaluated the Company's remaining businesses without Knife River Holding Company, the price at which shares of the Company common stock trade may fluctuate more significantly than might otherwise be typical, even with other market conditions, including general volatility, held constant. There can be no assurance that the combined value of the common stock of the two companies will be equal to or greater than what the value of the Company's common stock would have been had the proposed separation not occurred. It is possible that the Company's stockholders will sell shares of common stock for a variety of reasons. For example, such stockholders may not believe that the Company's remaining business profile or its level of market capitalization fits their investment objectives. The sale of significant amounts of the Company's common stock or the perception in the market that this will occur may lower the market price of the Company's common stock. The increased volatility of the Company's common stock price following the distribution may have a material adverse effect on its business, financial condition and results of operations.

The Company could experience temporary interruptions in business operations and incur additional costs as it separates information technology infrastructure and systems.
The Company is in the process of preparing information technology infrastructure and systems to support critical business functions at both the Company and Knife River Holding Company. If the Company cannot effectively transition both the Company and Knife River Holding Company to stand-alone systems and functions, they may experience disruptions to business operations, which could have a material adverse effect on profitability. In addition, the Company's costs for the operation of these systems may be higher than the amounts historically reflected in the consolidated financial statements.

The Company's review of options to optimize the value of its construction services business is subject to various risks and uncertainties and may not achieve its intended goals.
On November 3, 2022, the Company announced its intention to create two pure-play publicly traded companies, one focused on regulated energy delivery and the other on construction materials, and to achieve this future structure, the board authorized management to commence a strategic review process of MDU Construction Services. This process is active and ongoing. The uncertainties associated with this process, foreseen and unforeseen costs incurred, and efforts involved, may negatively affect the Company's operating results, business and the Company's relationships with employees, customers, suppliers and vendors. If the Company does not enter into or consummate a strategic transaction with respect to MDU Construction Services, the Company's business and results of operations could be adversely affected. Furthermore, if the Company does not consummate a transaction, the price of the Company's common stock may decline from the current market price, as the current market price might incorporate a market assumption that a transaction will be consummated. A failed transaction may also result in reduced employee morale and productivity, negative publicity and a negative impression of the Company in the investment community. Further, any disruptions to the Company's business resulting from any announcement and the uncertainty around the timing of a transaction, including any adverse changes in the Company's relationships with its customers, suppliers, vendors, and employees or recruiting and retention efforts, could continue or accelerate in the event of a failed transaction. Matters relating to any failed transaction may require significant costs and expenses and substantial management time and resources, which could otherwise have been devoted to operating and growing the Company's business.

Economic Risks

The Company is subject to government regulations that may have a negative impact on its business and its results of operations and cash flows. Statutory and regulatory requirements also may limit another party's ability to acquire the Company or impose conditions on an acquisition of or by the Company.
The Company's electric and natural gas transmission and distribution businesses are subject to comprehensive regulation by federal, state and local regulatory agencies with respect to, among other things, allowed rates of return and recovery of investments and costs; financing; rate structures; customer service; health care coverage and costs; taxes; franchises; recovery of fuel, purchased power and purchased natural gas costs; and construction and siting of generation and transmission facilities. These governmental regulations significantly influence the Company's operating environment and may affect its ability to recover costs from its customers. The Company is unable to predict the impact on operating results from future regulatory activities of any of these agencies. Changes in regulations or the imposition of additional regulations could have an adverse impact on the Company's results of operations and cash flows.

There can be no assurance that applicable regulatory commissions will determine that the Company's electric and natural gas transmission and distribution businesses' costs have been prudent, which could result in the disallowance of costs in setting rates for customers. Also, the regulatory process of approving rates for these businesses may not allow for timely and full recovery of the costs of providing services or a return on the Company's invested capital. Changes in regulatory requirements or operating conditions may require early retirement of certain assets. While regulation typically provides rate recovery for these retirements, there is no assurance regulators will allow full recovery of all remaining costs, which could leave stranded asset costs. Rising fuel costs could increase the risk that the utility businesses will not be able to fully recover those fuel costs from customers.

Approval from federal and state regulatory agencies would be needed for acquisition of the Company, as well as for certain acquisitions by the Company. The approval process could be lengthy and the outcome uncertain, which may deter potential acquirers from approaching the Company or impact the Company's ability to pursue acquisitions.

Economic volatility affects the Company's operations, as well as the demand for its products and services.
Unfavorable economic conditions can negatively affect the level of public and private expenditures on projects and the timing of these projects which, in turn, can negatively affect demand for the Company's products and services, primarily at the Company's construction businesses. The level of demand for construction products and services could be adversely impacted by the economic conditions in the industries the Company serves, as well as in the general economy. State and federal budget issues affect the funding available for infrastructure spending.

Economic conditions and population growth affect the electric and natural gas distribution businesses' growth in service territory, customer base and usage demand. Economic volatility in the markets served, along with economic conditions such as increased unemployment which could impact the ability of the Company's customers to make payments, could adversely affect the Company's results of operations, cash flows and asset values. Further, any material decreases in customers' energy demand, for economic or other reasons, could have an adverse impact on the Company's earnings and results of operations.

The Company's operations involve risks that may result from catastrophic events.
The Company's operations, particularly those related to electric and natural gas transmission and distribution, include a variety of inherent hazards and operating risks, such as product leaks; explosions; mechanical failures; vandalism; fires; pandemics; social or civil unrest; protests and riots; natural disasters; cyberattacks; acts of terrorism; and acts of war. These hazards and operating risks have occurred and may recur in the future, which could result in loss of human life; personal injury; property damage; environmental impacts; impairment of operations; and substantial financial losses. The Company maintains insurance against some, but not all, of these risks and losses. A significant incident could also increase regulatory scrutiny and result in penalties and higher amounts of capital expenditures and operational costs. Losses not fully covered by insurance could have an adverse effect on the Company’s financial position, results of operations and cash flows.

A disruption of the regional electric transmission grid, local distribution infrastructure or interstate natural gas infrastructure could negatively impact the Company's business and reputation. There have been cyber and physical attacks within the energy industry on energy infrastructure, such as substations, and such attacks may occur in the future. Because the Company's electric and natural gas utility and pipeline systems are part of larger interconnecting systems, any attacks on the Company's infrastructure causing a disruption could result in a significant decrease in revenues and an increase in system repair costs negatively impacting the Company's financial position, results of operations and cash flows.

The Company is subject to capital market and interest rate risks.
The Company's operations, particularly its electric and natural gas transmission and distribution businesses, require significant capital investment. Consequently, the Company relies on financing sources and capital markets as sources of liquidity for capital requirements not satisfied by cash flows from operations. If the Company is not able to access capital at competitive rates, the ability to implement business plans, make capital expenditures or pursue acquisitions the Company would otherwise rely on for future growth may be adversely affected. Market disruptions may increase the cost of borrowing or adversely affect the Company's ability to access one or more financial markets. Such disruptions could include:

- A significant economic downturn.
- The financial distress of unrelated industry leaders in the same line of business.
- Deterioration in capital market conditions.
- Turmoil in the financial services industry.
- Volatility in commodity prices.
- Pandemics, including COVID-19.
- War.
- Terrorist attacks.
- Cyberattacks.

The issuance of a substantial amount of the Company's common stock, whether issued in connection with an acquisition or otherwise, or the perception that such an issuance could occur, could have a dilutive effect on stockholders and/or may adversely affect the market price of the Company's common stock. Higher interest rates on borrowings have impacted and could further impact the Company's future operating results.

Financial market changes could impact the Company’s pension and postretirement benefit plans and obligations.
The Company has pension and postretirement defined benefit plans for some of its current and former employees. Assumptions regarding future costs, returns on investments, interest rates and other actuarial assumptions have a significant impact on the funding requirements and expense recorded relating to these plans. Adverse changes in economic indicators, such as consumer spending, inflation data, interest rate changes, political developments and threats of terrorism, among other things, can create volatility in the financial markets. These changes could impact the assumptions and negatively affect the value of assets held in the Company's pension and other postretirement benefit plans and may increase the amount and accelerate the timing of required funding contributions for those plans.

Significant changes in prices for commodities, labor or other production and delivery inputs could negatively affect the Company's businesses.
The Company's operations are exposed to fluctuations in prices for labor, oil, cement, raw materials and utilities. Prices are generally subject to change in response to fluctuations in supply and demand and other general economic and market conditions beyond the Company's control.

Fluctuations in oil and natural gas production, supplies and prices; fluctuations in commodity price basis differentials; political and economic conditions in oil-producing countries; actions of the Organization of Petroleum Exporting Countries; demand for oil due to economic conditions; war and other external factors impact the development of oil and natural gas supplies and the expansion and operation of natural gas pipeline systems. The Company has benefited from associated natural gas production in the Bakken, which has provided opportunities for organic growth projects. Depressed oil and natural gas prices, however, place pressure on the ability of oil exploration and production companies to meet credit requirements and can be a challenge if prices remain depressed long-term. Prolonged depressed prices for oil and natural gas could negatively affect the growth, results of operations, cash flows and asset values of the Company's electric, natural gas and pipeline businesses.

If oil and natural gas prices increase significantly, which has occurred and may reoccur, customer demand could decline for utility, pipeline and construction products and services, which could impact the Company's results of operations and cash flows. While the Company has fuel clause recovery mechanisms for its utility operations in all of the states where it operates, higher utility fuel costs could also significantly impact results of operations if such costs are not recovered. Delays in the collection of utility fuel cost recoveries, as compared to expenditures for fuel purchases, could also negatively impact the Company's cash flows. High oil and fuel prices also affect the margins realized and demand for construction materials and related contracting services.

High energy prices, specifically for diesel fuel, natural gas and liquid asphalt have impacted and could further affect the margins realized, as well as demand for construction materials and related contracting services. Increased labor costs, due to labor shortages, competition from other industries, or other factors, could negatively affect the Company's results of operations. Due to their size and weight, aggregates are costly and difficult to transport efficiently. The Company's construction materials products and services are generally localized around its aggregate sites and served by truck or in certain markets by rail or barge. The Company could be negatively impacted by freight costs due to rising fuel costs; rate increases for third party freight; truck, railcar or barge shortages, including shortages of truck drivers and rail crews; rail service interruptions; and minimum tonnage requirements, among other things.

In 2022 and 2021, the Company experienced elevated commodity and supply chain costs including the costs of labor, raw materials, energy-related products and other inputs used in the production and distribution of its products and services. At the construction materials and contracting business, recent inflationary pressures have significantly increased the cost of raw materials above 10% in comparison to average historical increases of 3%. The Company' construction businesses try to mitigate some or all cost increases through increases in selling prices, maintaining positive relationships with numerous raw material suppliers, and escalation clauses in contracting services contracts and fuel surcharges. To the extent price increases or other mitigating factors are not sufficient to offset these increased costs adequately or timely, and/or if the price increases result in a significant decrease in sales volumes, the Company's results of operations, financial position and cash flows could be negatively impacted.

Reductions in the Company's credit ratings could increase financing costs.
There is no assurance the Company's current credit ratings, or those of its subsidiaries, will remain in effect or that a rating will not be lowered or withdrawn by a rating agency. Events affecting the Company's financial results may impact its cash flows and credit metrics, potentially resulting in a change in the Company's credit ratings. The Company's credit ratings may also change as a result of the differing methodologies or changes in the methodologies used by the rating agencies.

Increasing costs associated with health care plans may adversely affect the Company's results of operations.
The Company's self-insured costs of health care benefits for eligible employees continues to increase. Increasing quantities of large individual health care claims and an overall increase in total health care claims could have an adverse impact on operating results, financial position and liquidity. Legislation related to health care could also change the Company's benefit program and costs.

The Company is exposed to risk of loss resulting from the nonpayment and/or nonperformance by the Company's customers and counterparties.
If the Company's customers or counterparties experience financial difficulties, which has occurred and may recur in the future, the Company could experience difficulty in collecting receivables. Nonpayment and/or nonperformance by the Company's customers and counterparties, particularly customers and counterparties of the Company’s pipeline, construction materials and contracting and construction services businesses for large construction projects, could have a negative impact on the Company's results of operations and cash flows. The Company could also have indirect credit risk from participating in energy markets such as MISO in which credit losses are socialized to all participants.

Changes in tax law may negatively affect the Company's business.

Changes to federal, state and local tax laws have the ability to benefit or adversely affect the Company's earnings and customer costs. Significant changes to corporate tax rates could result in the impairment of deferred tax assets that are established based on existing law at the time of deferral. Changes to the value of various tax credits could change the economics of resources and the resource selection for the electric generation business. Regulation incorporates changes in tax law into the rate-setting process for the regulated energy delivery businesses, which could create timing delays before the impact of changes are realized.

The Company's operations could be negatively impacted by import tariffs and/or other government mandates.

The Company operates in or provides services to capital intensive industries in which federal trade policies could significantly impact the availability and cost of materials. Imposed and proposed tariffs could significantly increase the prices and delivery lead times on raw materials and finished products that are critical to the Company and its customers, such as aluminum and steel. Prolonged lead times on the delivery of raw materials and further tariff increases on raw materials and finished products could adversely affect the Company's business, financial condition and results of operations.

Pandemics, including COVID-19, may have a negative impact on the Company's business operations, revenues, results of operations, liquidity and cash flows.

Pandemics have disrupted national, state and local economies. To the extent pandemics adversely impact the Company's businesses, operations, revenues, liquidity or cash flows, they could also have a heightened effect on other risks described in this section. The degree to which pandemics impact the Company depends on, among other things, federal and state mandates, actions taken by governmental authorities, availability, timing and effectiveness of vaccines being administered, and the pace and extent to which the economy recovers and operates under normal market conditions.

Operational Risks

Significant portions of the Company’s natural gas pipelines and power generation and transmission facilities are aging. The aging infrastructure may require significant additional maintenance or replacement that could adversely affect the Company’s results of operations.

Certain risks increase as the Company's energy delivery infrastructure ages, including breakdown or failure of equipment, pipeline leaks and fires developing from power lines, all of which have occurred and may recur in the future resulting in material costs. Aging infrastructure is more prone to failure, which increases maintenance costs, unplanned outages and the need to replace facilities. Even if properly maintained, reliability may ultimately deteriorate and negatively affect the Company’s ability to serve its customers, which could result in increased costs associated with regulatory oversight. The costs associated with maintaining the aging infrastructure and capital expenditures for new or replacement infrastructure could cause rate volatility and/or regulatory lag in some jurisdictions. If, at the end of its life, the investment costs of a facility have not been fully recovered, the Company may be adversely affected if commissions do not allow such costs to be recovered in rates. Such impacts of aging infrastructure could adversely affect the Company’s results of operations and cash flows.

Additionally, hazards from aging infrastructure could result in serious injury, loss of human life, significant damage to property, environmental impacts and impairment of operations, which in turn could lead to substantial financial losses. The location of facilities near populated areas, including residential areas, business centers, industrial sites and other public gathering places, could increase the damages resulting from these risks. A major incident involving another natural gas system could lead to additional capital expenditures, increased regulation, and fines and penalties on natural gas utilities and pipelines. The occurrence of any of these events could adversely affect the Company’s results of operations, financial position and cash flows.

The Company's utility and pipeline operations are subject to planning risks.

Most electric and natural gas utility investments, including natural gas transmission pipeline investments, are made with the intent of being used for decades. In particular, electric transmission and generation resources are planned well in advance of when they are placed into service based upon resource plans using assumptions over the planning horizon, including sales growth, commodity prices, equipment and construction costs, regulatory treatment, available technology and public policy. Public policy changes and technology advancements related to areas such as energy efficient appliances and buildings, renewable and distributive electric generation and storage, carbon dioxide emissions, electric vehicle penetration, restrictions on or disallowance of new or existing services, and natural gas availability and cost may significantly impact the planning assumptions. Changes in critical planning assumptions may result in excess generation, transmission and distribution resources creating increased per customer costs and downward pressure on load growth. These changes could also result in a stranded investment if the Company is unable to fully recover the costs of its investments.

The regulatory approval, permitting, construction, startup and/or operation of pipelines, power generation and transmission facilities, and aggregate reserves may involve unanticipated events, delays and unrecoverable costs.

The construction, startup and operation of natural gas pipelines and electric power generation and transmission facilities involve many risks, which may include delays; breakdown or failure of equipment; inability to obtain required governmental permits and approvals; inability to obtain or renew easements; public opposition; inability to complete financing; inability to negotiate acceptable equipment acquisition, construction, fuel supply, off-take, transmission, transportation or other material agreements; changes in markets and market prices for power; cost increases and overruns; the risk of performance below expected levels of output or efficiency; and the inability to obtain full cost recovery in regulated rates. Additionally, in a number of states in which the Company operates, it can be difficult to permit new aggregate sites or expand existing aggregate sites due to community resistance and regulatory requirements, among other things. Such unanticipated events could negatively impact the Company's business, its results of operations and cash flows.

Operating or other costs required to comply with current or potential pipeline safety regulations and potential new regulations under various agencies could be significant. The regulations require verification of pipeline infrastructure records by pipeline owners and operators to confirm the maximum allowable operating pressure of certain lines. Increased emphasis on pipeline safety and increased regulatory scrutiny may result in penalties and higher costs of operations. If these costs are not fully recoverable from customers, they could have an adverse effect on the Company's results of operations and cash flows.

The backlogs at the Company's construction materials and contracting and construction services businesses may not accurately represent future revenue.
Backlog consists of the uncompleted portion of services to be performed under job-specific contracts. Contracts are subject to delay, default or cancellation, and contracts in the Company's backlog are subject to changes in the scope of services to be provided, as well as adjustments to the costs relating to the applicable contracts. Backlog may also be affected by project delays or cancellations resulting from weather conditions, external market factors and economic factors beyond the Company's control, among other things. Accordingly, there is no assurance that backlog will be realized. The timing of contract awards, duration of large new contracts and the mix of services can significantly affect backlog. Backlog at any given point in time may not accurately represent the revenue or net income that is realized in any period. Also, the backlog as of the end of the year may not be indicative of the revenue and net income expected to be earned in the following year and should not be relied upon as a stand-alone indicator of future revenues or net income.

The Company's participation in joint venture contracts may have a negative impact on its reputation, business operations, revenues, results of operations, liquidity and cash flows.
The Company enters into certain joint venture arrangements typically to bid and execute particular projects. Generally, these agreements are directly with a third-party client; however, services may be performed by the venture, the joint venture partners or a combination thereof. Engaging in joint venture contracts exposes the Company to risks and uncertainties, some of which are outside the Company's control.

The Company is reliant on joint venture partners to satisfy their contractual obligations, including obligations to commit working capital and equity, and to perform the work as outlined in the agreement. Failure to do so could result in the Company providing additional investments or services to address such performance issues. If the Company is unable to satisfactorily resolve any partner performance issues, the customer could terminate the contract, opening the Company to legal liability which could negatively impact the Company's reputation, revenues, results of operations, liquidity and cash flows.

Supply chain disruptions may adversely affect Company operations.
The Company relies on third-party vendors and manufacturers to supply many of the materials necessary for its operations. Global logistic disruptions have impacted the flow of materials and restricted global trade flows. Manufacturers are competing for a limited supply of key commodities and logistical capacity which has impacted lead times, pricing, supply and demand. National and regional demand for cement and liquid asphalt may at times outpace the supply in the market. This imbalance creates a temporary shortage which may cause prices to increase faster than downstream products. Disruptions or delays in receiving materials; price increases from suppliers or manufacturers; or inability to source needed materials, which has occurred and could reoccur, could adversely affect the Company's results of operations, financial condition and cash flows.

Environmental and Regulatory Risks

The Company's operations could be adversely impacted by climate change.
Severe weather events, such as tornadoes, hurricanes, rain, drought, ice and snowstorms, and high and low temperature extremes, occur in regions in which the Company operates and maintains infrastructure. Climate change could change the frequency and severity of these weather events, which may create physical and financial risks to the Company. Such risks could have an adverse effect on the Company's financial condition, results of operations and cash flows. To date, the Company has not experienced any material impacts to its financial condition, results of operations or cash flows due to the physical effects of climate change.

Severe weather events may damage or disrupt the Company's electric and natural gas transmission and distribution facilities, which could result in disruption of service and ability to meet customer demand and increase maintenance or capital costs to repair facilities and restore customer service. The cost of providing service could increase if the frequency of severe weather events increases because of climate change or otherwise. The Company may not recover all costs related to mitigating these physical risks.

Increases in severe weather conditions or extreme temperatures may cause infrastructure construction projects to be delayed or canceled and limit resources available for such projects resulting in decreased revenue or increased project costs at the construction materials and contracting and construction services businesses. In addition, drought conditions could restrict the availability of water supplies, inhibiting the ability of the construction businesses to conduct operations.

Utility customers' energy needs vary with weather conditions, primarily temperature and humidity. For residential customers, heating and cooling represent the largest energy use. To the extent weather conditions are affected by climate change, customers' energy use could increase or decrease. Increased energy use by its utility customers due to weather may require the Company to invest in additional generating assets, transmission and other infrastructure to serve increased load. Decreased energy use due to weather may result in decreased revenues. Extreme weather conditions, such as uncommonly long periods of high or low ambient temperature in general require more system backup, adding to costs, and can contribute to increased system stress, including service interruptions. Weather conditions outside of the Company's service territory could also have an impact on revenues. The Company buys and sells electricity that might be generated outside its service territory, depending upon system needs and market opportunities. Extreme temperatures may create high energy demand and raise electricity prices, which could increase the cost of energy provided to customers.

Climate change may impact a region’s economic health, which could impact revenues at all of the Company's businesses. The Company's financial performance is tied to the health of the regional economies served. The Company provides natural gas and electric utility service, as well as construction materials and services, for some states and communities that are economically affected by the agriculture industry. Increases in severe weather events or significant changes in temperature and precipitation patterns could adversely affect the agriculture industry and, correspondingly, the economies of the states and communities affected by that industry.

The insurance industry may be adversely affected by severe weather events, which may impact availability of insurance coverage, insurance premiums and insurance policy terms.

The Company may be subject to litigation related to climate change. Costs of such litigation could be significant, and an adverse outcome could require substantial capital expenditures, changes in operations and possible payment of penalties or damages, which could affect the Company's results of operations and cash flows if the costs are not recoverable in rates.

The price of energy also has an impact on the economic health of communities. The cost of additional regulatory requirements related to climate change, such as regulation of carbon dioxide emissions under the federal Clean Air Act, requirements to replace fossil fuels with renewable energy or credits, or other environmental regulation or taxes, could impact the availability of goods and the prices charged by suppliers, which would normally be borne by consumers through higher prices for energy and purchased goods, and could adversely impact economic conditions of areas served by the Company. To the extent financial markets view climate change and emissions of GHGs as a financial risk, this could negatively affect the Company's ability to access capital markets or result in less competitive terms and conditions.

The Company's operations are subject to environmental laws and regulations that may increase costs of operations, impact or limit business plans, or expose the Company to environmental liabilities.

The Company is subject to environmental laws and regulations affecting many aspects of its operations, including air and water quality, wastewater discharge, the generation, transmission and disposal of solid waste and hazardous substances, aggregate permitting and other environmental considerations. These laws and regulations can increase capital, operating and other costs; cause delays as a result of litigation and administrative proceedings; and create compliance, remediation, containment, monitoring and reporting obligations, particularly relating to electric generation, permitting and environmental compliance for construction material facilities, and natural gas transmission and storage operations. Environmental laws and regulations can also require the Company to install pollution control equipment at its facilities, clean up spills and other contamination and correct environmental hazards, including payment of all or part of the cost to remediate sites where the Company's past activities, or the activities of other parties, caused environmental contamination. These laws and regulations generally require the Company to obtain and comply with a variety of environmental licenses, permits, inspections and other approvals and may cause the Company to shut down existing facilities due to difficulties in assuring compliance or where the cost of compliance makes operation of the facilities uneconomical. Although the Company strives to comply with all applicable environmental laws and regulations, public and private entities and private individuals may interpret the Company's legal or regulatory requirements differently and seek injunctive relief or other remedies against the Company. The Company cannot predict the outcome, financial or operational, of any such litigation or administrative proceedings.

Existing environmental laws and regulations may be revised and new laws and regulations seeking to protect the environment may be adopted or become applicable to the Company. These laws and regulations could require the Company to limit the use or output of certain facilities; restrict the use of certain fuels; prohibit or restrict new or existing services; replace certain fuels with renewable fuels; retire and replace certain facilities; install pollution controls; remediate environmental impacts; remove or reduce environmental hazards; or forego or limit the development of resources. Revised or new laws and regulations that increase compliance and disclosure costs and/or restrict operations, particularly if costs are not fully recoverable from customers, could adversely affect the Company's results of operations and cash flows.

Stakeholder actions and increased regulatory activity related to environmental, social and governance matters, particularly climate change and reducing GHG emissions, could adversely impact the Company's operation, costs of or access to capital and impact or limit business plans.

The Company, primarily at its electric, natural gas distribution and pipeline businesses, is facing increasing stakeholder scrutiny related to environmental, social and governance matters. Recently, the Company has seen a rise in certain stakeholders, such as investors, customers, employees and lenders, placing increasing importance on the impacts and social cost associated with climate change. Concern that GHG emissions contribute to global climate change has led to international, federal, state and local legislative and regulatory proposals to reduce or mitigate the effects of GHG emissions. The Company’s primary GHG emission is carbon dioxide from fossil fuels combustion at Montana-Dakota's electric generating facilities, particularly its coal-fired facilities.

Treaties, legislation or regulations to reduce GHG emissions in response to climate change may be adopted that affect the Company's utility and pipeline operations by requiring additional energy conservation efforts or renewable energy sources, limiting emissions, imposing carbon taxes or other compliance costs; as well as other mandates that could significantly increase capital expenditures and operating costs or reduce demand for the Company's utility services. If the Company’s utility and pipeline operations do not receive timely and full recovery of GHG emission compliance costs from customers, then such costs could adversely impact the results of operations and cash flows. Significant reductions in demand for the

Company's utility and pipeline services as a result of increased costs or emissions limitations could also adversely impact the results of operations and cash flows.

The Company monitors, analyzes and reports GHG emissions from its other operations as required by applicable laws and regulations. The Company will continue to monitor GHG regulations and their potential impact on operations.

Due to the uncertain availability of technologies to control GHG emissions and the unknown obligations that potential GHG emission legislation or regulations may create, the Company cannot determine the potential financial impact on its operations.

In addition, the increasing focus on climate change and stricter regulatory requirements may result in the Company facing adverse reputational risks associated with certain of its operations producing GHG emissions. There have also been efforts to discourage the investment community from investing in equity and debt securities of companies engaged in fossil fuel related business and pressuring lenders to limit funding to such companies. Additionally, some insurance carriers have indicated an unwillingness to insure assets and operations related to certain fossil fuels. Although the Company has not experienced difficulties in these areas, if the Company is unable to satisfy the increasing climate-related expectations of certain stakeholders, the Company may suffer reputational harm, which may cause its stock price to decrease or difficulty in accessing the capital or insurance markets. Such efforts, if successfully directed at the Company, could increase the costs of or access to capital or insurance and interfere with business operations and ability to make capital expenditures.

Other Risks

The Company's various businesses are seasonal and subject to weather conditions that could adversely affect the Company's operations, revenues and cash flows.

The Company's results of operations could be affected by changes in the weather. Weather conditions influence the demand for electricity and natural gas and affect the price of energy commodities. Utility operations have historically generated lower revenues when weather conditions are cooler than normal in the summer and warmer than normal in the winter, particularly in jurisdictions that do not have weather normalization mechanisms in place. Where weather normalization mechanisms are in place, there is no assurance the Company will continue to receive such regulatory protection from adverse weather in future rates.

Adverse weather conditions, which have occurred and may recur, such as heavy or sustained rainfall or snowfall, storms, wind and colder weather may affect the demand for products and the ability to perform services at the construction businesses and affect ongoing operation and maintenance and construction activities for the electric and natural gas transmission and distribution businesses. In addition, severe weather can be destructive, causing outages and property damage, which could require additional remediation costs. The Company could also be impacted by drought conditions, which may restrict the availability of water supplies and inhibit the ability of the construction businesses to conduct operations. As a result, unusual or adverse weather conditions could negatively affect the Company's results of operations, financial position and cash flows.

Competition exists in all of the Company's businesses.

The Company's businesses are subject to competition. Construction services' competition is based primarily on price and reputation for quality, safety and reliability. Construction materials products are marketed under highly competitive conditions and are subject to competitive forces such as price, service, delivery time and proximity to the customer. The electric utility and natural gas businesses also experience competitive pressures as a result of consumer demands, technological advances and other factors. The pipeline business competes with several pipelines for access to natural gas supplies and for transportation and storage business. New acquisition opportunities are subject to competitive bidding environments which impact prices the Company must pay to successfully acquire new properties and acquisition opportunities to grow its business. The Company's failure to effectively compete could negatively affect the Company's results of operations, financial position and cash flows.

The Company's operations may be negatively affected if it is unable to obtain, develop and retain key personnel and skilled labor forces.

The Company must attract, develop and retain executive officers and other professional, technical and skilled labor forces with the skills and experience necessary to successfully manage, operate and grow the Company's businesses. Due to the changing workforce demographics and a lack of younger employees who are qualified to replace employees as they retire and remote work opportunities, among other things, competition for these employees is high. In some cases competition for these employees is on a regional or national basis. At times of low unemployment, it can be difficult for the Company to attract and retain qualified and affordable personnel. A shortage in the supply of skilled personnel creates competitive hiring markets, increased labor expenses, decreased productivity and potentially lost business opportunities to support the Company's operating and growth strategies. Additionally, if the Company is unable to hire employees with the requisite skills, the Company may be forced to incur significant training expenses. As a result, the Company's ability to maintain productivity, relationships with customers, competitive costs, and quality services is limited by the ability to employ, retain and train the necessary skilled personnel and could negatively affect the Company's results of operations, financial position and cash flows.

The Company's construction materials and contracting and construction services businesses may be exposed to warranty claims.

The Company, particularly its construction businesses, may provide warranties guaranteeing the work performed against defects in workmanship and material. If warranty claims occur, they may require the Company to re-perform the services or to repair or replace the warranted item at a cost to the Company and could also result in other damages if the Company is not able to adequately satisfy warranty obligations. In addition, the Company may be required under contractual arrangements with customers to warrant any defects from subcontractors or failures in materials the Company purchased from third parties. While the Company generally requires suppliers to provide warranties that are consistent with those the Company provides to customers, if any of the suppliers default on their warranty obligations to the Company, the Company may nonetheless incur costs to repair or replace the defective materials. Costs incurred as a result of warranty claims could adversely affect the Company's results of operations, financial condition and cash flows.

The Company is a holding company and relies on cash from its subsidiaries to pay dividends.

The Company's investments in its subsidiaries comprise the Company's primary assets. The Company depends on earnings, cash flows and dividends from its subsidiaries to pay dividends on its common stock. Regulatory, contractual and legal limitations, as well as their capital requirements, affect the ability of the subsidiaries to pay dividends to the Company and thereby could restrict or influence the Company's ability or decision to pay dividends on its common stock, which could adversely affect the Company's stock price.

Costs related to obligations under MEPPs could have a material negative effect on the Company's results of operations and cash flows.

Various operating subsidiaries of the Company participate in MEPPs for employees represented by certain unions. The Company is required to make contributions to these plans in amounts established under numerous collective bargaining agreements between the operating subsidiaries and those unions.

The Company may be obligated to increase its contributions to underfunded plans that are classified as being in endangered, seriously endangered or critical status as defined by the Pension Protection Act of 2006. Plans classified as being in one of these statuses are required to adopt RPs or FIPs to improve their funded status through increased contributions, reduced benefits or a combination of the two.

The Company may also be required to increase its contributions to MEPPs if the other participating employers in such plans withdraw from the plans and are not able to contribute amounts sufficient to fund the unfunded liabilities associated with their participation in the plans. The amount and timing of any increase in the Company's required contributions to MEPPs may depend upon one or more factors, including the outcome of collective bargaining; actions taken by trustees who manage the plans; actions taken by the plans' other participating employers; the industry for which contributions are made; future determinations that additional plans reach endangered, seriously endangered or critical status; newly-enacted government laws or regulations and the actual return on assets held in the plans; among others. The Company could experience increased operating expenses as a result of required contributions to MEPPs, which could have an adverse effect on the Company's results of operations, financial position or cash flows.

In addition, pursuant to ERISA, as amended by MPPAA, the Company could incur a partial or complete withdrawal liability upon withdrawing from a plan, exiting a market in which it does business with a union workforce or upon termination of a plan. The Company could also incur additional withdrawal liability if its withdrawal from a plan is determined by that plan to be part of a mass withdrawal.

Technology disruptions or cyberattacks could adversely impact the Company's operations.

The Company uses technology in substantially all aspects of its business operations and requires uninterrupted operation of information technology and operation technology systems, including disaster recovery and backup systems and network infrastructure. While the Company has policies, procedures and processes in place designed to strengthen and protect these systems, they may be vulnerable to physical and cybersecurity failures or unauthorized access, due to:

- hacking,
- human error,
- theft,
- sabotage,
- malicious software,
- ransomware,
- third-party compromise,
- acts of terrorism,
- acts of war,
- acts of nature or
- other causes.

Although there are manual processes in place, should a compromise or system failure occur, interdependencies to technology may disrupt the Company's ability to fulfill critical business functions. This may include interruption of electric generation, transmission and distribution facilities, natural gas storage and pipeline facilities and facilities for delivery of construction materials or other products and services, any of which could adversely affect the Company's reputation, business, cash flows and results of operations or subject the Company to legal or regulatory liabilities and increased costs. Additionally, the Company's electric generation and transmission systems and natural gas pipelines are part of interconnected systems with other operators' facilities; therefore, a cyber-related disruption in another operator's system could negatively impact the Company's business.

The Company’s accounting systems and its ability to collect information and invoice customers for products and services could be disrupted. If the Company’s operations are disrupted, it could result in decreased revenues and remediation costs that could adversely affect the Company's results of operations and cash flows.

The Company is subject to cybersecurity and privacy laws, regulations and security directives of many government agencies, including TSA, FERC and NERC. NERC issues comprehensive regulations and standards surrounding the security of bulk power systems and continually updates these requirements, as well as establishing new requirements with which the utility industry must comply. As these regulations evolve, the Company may experience increased compliance costs and may be at higher risk for violating these standards. Experiencing a cybersecurity incident could cause the Company to be non-compliant with applicable laws and regulations, causing the Company to incur costs related to legal claims, proceedings and regulatory fines or penalties.

The Company, through the ordinary course of business, requires access to sensitive customer, supplier, employee and Company data. While the Company has implemented extensive security measures, including limiting the amount of sensitive information retained, a breach of its systems could compromise sensitive data and could go unnoticed for some time. Such an event could result in negative publicity and reputational harm, remediation costs, legal claims and fines that could have an adverse effect on the Company's financial results. Third-party service providers that perform critical business functions for the Company or have access to sensitive information within the Company also may be vulnerable to security breaches and information technology risks that could adversely affect the Company.

The Company’s information systems experience ongoing and often sophisticated cyberattacks by a variety of sources with the apparent aim to breach the Company's cyber-defenses. The Company may face increased cyber risk due to the increased use of employee owned devices, work from home arrangements, and the proposed separation of Knife River Holding Company. Although the incidents the Company has experienced to date have not had a material effect on its business, financial condition or results of operations, such incidents could have a material adverse effect in the future as cyberattacks continue to increase in frequency and sophistication. The Company is continuously reevaluating the need to upgrade and/or replace systems and network infrastructure. These upgrades and/or replacements could adversely impact operations by imposing substantial capital expenditures, creating delays or outages, or experiencing difficulties transitioning to new systems. System disruptions, if not anticipated and appropriately mitigated, could adversely affect the Company.

General risk factors that could impact the Company's businesses.
The following are additional factors that should be considered for a better understanding of the risks to the Company. These factors may negatively impact the Company's financial results in future periods.

- Acquisition, disposal and impairments of assets or facilities.
- Changes in present or prospective electric generation.
- Population decline and demographic patterns in the Company's areas of service.
- The cyclical nature of large construction projects at certain operations.
- Labor negotiations or disputes.
- Succession planning.
- Attracting and retaining employees.
- Stockholder and environmental activism.
- Inability of contract counterparties to meet their contractual obligations.
- The inability to effectively integrate the operations and the internal controls of acquired companies.

Item 1B. Unresolved Staff Comments

The Company has no unresolved comments with the SEC.

Item 3. Legal Proceedings

SEC regulations require the Company to disclose certain information about proceedings arising under federal, state or local environmental provisions if the Company reasonably believes that such proceedings may result in monetary sanctions above a stated threshold. Pursuant to SEC regulations, the Company has adopted a threshold of $1.0 million for purposes of determining whether disclosure of any such proceedings is required.

For information regarding legal proceedings required by this item, see Item 8 - Note 21, which is incorporated herein by reference.

Item 4. Mine Safety Disclosures

For information regarding mine safety violations or other regulatory matters required by Section 1503(a) of the Dodd-Frank Act and Item 104 of Regulation S-K, see Exhibit 95 to this Form 10-K, which is incorporated herein by reference.

Item 5. Market for the Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

The Company's common stock is listed on the New York Stock Exchange under the symbol "MDU."

As of December 31, 2022, the Company's common stock was held by approximately 9,600 stockholders of record.

The Company depends on earnings and dividends from its subsidiaries to pay dividends on common stock. The Company has paid uninterrupted dividends to stockholders for 85 consecutive years with an increase in the payout amount for the last 32 consecutive years. The declaration and payment of dividends is at the sole discretion of the board of directors, subject to limitations imposed by agreements governing the Company's indebtedness, federal and state laws, and applicable regulatory limitations. For more information on factors that may limit the Company's ability to pay dividends, see Item 8 - Note 12.

The following table includes information with respect to the Company's purchase of equity securities:

ISSUER PURCHASES OF EQUITY SECURITIES

Period	(a) Total Number of Shares (or Units) Purchased (1)	(b) Average Price Paid per Share (or Unit)	(c) Total Number of Shares (or Units) Purchased as Part of Publicly Announced Plans or Programs (2)	(d) Maximum Number (or Approximate Dollar Value) of Shares (or Units) that May Yet Be Purchased Under the Plans or Programs (2)
October 1 through October 31, 2022	—	—	—	—
November 1 through November 30, 2022	40,800	$30.64	—	—
December 1 through December 31, 2022	—	—	—	—
Total	40,800	$30.64	—	—

(1) Represents shares of common stock purchased on the open market in connection with annual stock grants made to the Company's non-employee directors and for those directors who elected to receive additional shares of common stock in lieu of a portion of their cash retainer.
(2) Not applicable. The Company does not currently have in place any publicly announced plans or programs to repurchase equity securities.

Item 6.

Reserved.

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operation

The Company is Building a Strong America® by providing essential infrastructure and services. The Company and its employees work hard to keep the economy of America moving with the products and services provided, which include powering, heating and connecting homes, factories, offices and stores; and building roads, highways, data infrastructure and airports. The Company is authorized to conduct business in nearly every state in the United States and during peak construction season has employed over 16,800 employees. The Company's organic investments are strong drivers of high-quality earnings and continue to be an important part of the Company's growth. Management believes the Company is well positioned in the industries and markets in which it operates.

As part of the Company's strategic planning to optimize stockholder value, the Company announced its board of directors unanimously approved a plan to pursue a separation of Knife River from the Company on August 4, 2022, and, as a next step in its strategic planning, on November 3, 2022, the Company announced the board of directors' plan to create two pure-play companies: a leading construction materials company and a regulated energy delivery company. The separation of Knife River is planned as a tax-free spinoff transaction to the Company's stockholders for U.S. federal income tax purposes. The transaction is expected to result in two independent, publicly traded companies. Completion of the separation will be subject to, among other things, the effectiveness of a registration statement on Form 10 with the SEC, final approval from the Company's board of directors, receipt of one or more tax opinions and a private letter ruling from the IRS, and other customary conditions. The Company may, at any time and for any reason until the proposed transaction is complete, abandon the separation or modify or change its terms. The separation is expected to be complete in the second quarter of 2023, but there can be no assurance regarding the ultimate timing of the separation or that the separation will ultimately occur. In addition, the board has authorized management to commence a strategic review process for MDU Construction Services with the objective of achieving the board's goal of creating two pure-play public companies. The strategic review is well underway, and the Company anticipates completing it during the second quarter of 2023. See Item 1A - Risk Factors for a description of the risks and uncertainties with the proposed future structure. The Company incurred costs in connection with the announced strategic initiatives in 2022, as noted in the Business Segment Financial and Operating Data section, and expects to continue to incur these costs until the initiatives are completed.

The Company continues to manage the inflationary pressures experienced throughout the United States, including the impact that inflation, rising interest rates, commodity price volatility and supply chain disruptions may have on its business and customers and proactively looks for ways to lessen the impact to its business. Inflation rates in the Unites States increased significantly during 2022, relative to historical precedent, and may continue to rise. The Company has continued to evaluate its businesses and has increased pricing for its products and services where necessary as evidenced by the increase in revenues recognized in 2022. The ability to raise selling prices to cover higher costs due to inflation are subject to customer demand, industry competition and the availability of materials, among other things. Rising interest rates have resulted in, and will likely continue to result in, higher borrowing costs on new debt, resulting in impacts to the Company's asset valuations and negatively impacting the purchasing power of its customers. For more information on possible impacts to the Company's businesses, see the Outlook for each segment below and Item 1A - Risk Factors.

Consolidated Earnings Overview

The following table summarizes the contribution to the consolidated income by each of the Company's business segments.

Years ended December 31,	**2022**	2021	2020
	(In millions, except per share amounts)		
Electric	**$ 57.1**	$ 51.9	$ 55.6
Natural gas distribution	**45.2**	51.6	44.0
Pipeline	**35.3**	40.9	37.0
Construction materials and contracting	**116.2**	129.8	147.3
Construction services	**124.8**	109.4	109.7
Other	**(11.3)**	(5.9)	(3.1)
Income from continuing operations	**367.3**	377.7	390.5
Discontinued operations, net of tax	**.2**	.4	(.3)
Net income	**$ 367.5**	$ 378.1	$ 390.2
Earnings per share - basic:			
Income from continuing operations	**$ 1.81**	$ 1.87	$ 1.95
Discontinued operations, net of tax	**—**	—	—
Earnings per share - basic	**$ 1.81**	$ 1.87	$ 1.95
Earnings per share - diluted:			
Income from continuing operations	**$ 1.81**	$ 1.87	$ 1.95
Discontinued operations, net of tax	**—**	—	—
Earnings per share - diluted	**$ 1.81**	$ 1.87	$ 1.95

2022 compared to 2021 The Company's consolidated earnings decreased $10.6 million.

The Company experienced decreased earnings at the construction materials and contracting, natural gas distribution and pipeline businesses. While the construction materials and contracting business experienced higher average pricing on materials and increased contracting revenues, results were negatively impacted by ongoing inflationary pressures, including energy and other operating costs. The natural gas distribution business experienced higher operating expenses, including subcontractor costs, as well as higher interest and depreciation expenses, partially offset by increased sales volumes and approved rate recovery in certain jurisdictions. The pipeline business experienced higher interest expense and lower non-regulated project margins, partially offset by the net benefit of the North Bakken Expansion project. The Company's earnings were further impacted by $21.0 million in lower returns on the Company's nonqualified benefit plan investments, as discussed in Note 8, and the costs incurred in connection with the announced strategic initiatives of $12.7 million, after tax. Partially offsetting the decreases were increased earnings at the construction services business resulting from higher electrical and mechanical project margins and earnings from the segment's joint ventures, partially offset by higher overall operating expenses related to increased payroll-related costs and expected credit losses. The electric business benefited from interim rate relief in North Dakota, higher net transmission revenues and higher retail sales volumes as a result of colder weather, as well as lower operation and maintenance expenses, largely related to plant closures.

2021 compared to 2020 The Company's consolidated earnings decreased $12.1 million.

Negatively impacting the Company's earnings was a decrease in gross margin across most product lines at the construction materials and contracting business resulting from labor constraints; increased material costs, including asphalt oil and diesel fuel; higher equipment, repair and maintenance costs; and less available paving work in certain regions. The decrease was partially offset by higher AFUDC for the construction of the North Bakken Expansion project and higher earnings due to increased natural gas transportation volumes at the pipeline business. Also positively impacting earnings was higher operating income at the electric and natural gas businesses, largely a result of approved rate relief in certain jurisdictions, partially offset by higher operations and maintenance expenses.

A discussion of key financial data from the Company's business segments follows.

Business Segment Financial and Operating Data

Following are key financial and operating data for each of the Company's business segments. Also included are highlights on key growth strategies, projections and certain assumptions for the Company and its subsidiaries and other matters of the Company's business segments. Many of these highlighted points are "forward-looking statements." For more information, see Part I - Forward-Looking Statements. There is no assurance that the Company's projections, including estimates for growth and changes in earnings, will in fact be achieved. Please refer to assumptions contained in this section, as well as the various important factors listed in Item 1A - Risk Factors. Changes in such assumptions and factors could cause actual future results to differ materially from the Company's growth and earnings projections.

For information pertinent to various commitments and contingencies, see Item 8 - Notes to Consolidated Financial Statements. For a summary of the Company's business segments, see Item 8 - Note 17.

Electric and Natural Gas Distribution

Strategy and challenges The electric and natural gas distribution segments provide electric and natural gas distribution services to customers, as discussed in Items 1 and 2 - Business Properties. Both segments strive to be top performing utility companies measured by integrity, employee safety and satisfaction, customer service and stockholder return. The segments provide safe, reliable, competitively priced and environmentally responsible energy service to customers while focusing on growth and expansion opportunities within and beyond its existing territories. The Company is focused on cultivating organic growth while managing operating costs and monitoring opportunities for these segments to retain, grow and expand their customer base through extensions of existing operations, including building and upgrading electric generation, transmission and distribution, and natural gas systems, and through selected acquisitions of companies and properties with similar operating and growth objectives at prices that will provide stable cash flows and an opportunity to earn a competitive return on investment. The continued efforts to create operational improvements and efficiencies across both segments promotes the Company's business integration strategy. The primary factors that impact the results of these segments are the ability to earn authorized rates of return, the cost of natural gas, cost of electric fuel and purchased power, weather, climate change initiatives, competitive factors in the energy industry, population growth and economic conditions in the segments' service areas.

The electric and natural gas distribution segments are subject to extensive regulation in the jurisdictions where they conduct operations with respect to costs, timely recovery of investments and permitted returns on investment. The Company is focused on modernizing utility infrastructure to meet the varied energy needs of both its customers and communities while ensuring the delivery of safe, reliable, affordable and environmentally responsible energy. The segments continue to invest in facility upgrades to be in compliance with existing and known future regulations. To assist in the reduction of regulatory lag in obtaining revenue increases to align with increased investments, tracking mechanisms have been implemented in certain jurisdictions. The Company also seeks rate adjustments for operating costs and capital investments, as well as reasonable returns on investments not covered by tracking mechanisms. For more information on the Company's tracking mechanisms and recent cases, see Items 1 and 2 - Business Properties and Item 8 - Note 20.

These segments are also subject to extensive regulation related to certain operational and environmental compliance, cybersecurity, permit terms and system integrity. Both segments are faced with the ongoing need to actively evaluate cybersecurity processes and procedures related to its transmission and distribution systems for opportunities to further strengthen its cybersecurity protections. Within the past year, there have been cyber and physical attacks within the energy industry on energy infrastructure, such as substations, and the Company continues to evaluate the safeguards implemented to protect its electric and natural gas utility systems. Implementation of enhancements and additional requirements to protect the Company's infrastructure is ongoing.

To date, many states have enacted, and others are considering, mandatory clean energy standards requiring utilities to meet certain thresholds of renewable and/or carbon-free energy supply. The current presidential administration has made climate change a focus, as further discussed in the Outlook section. Over the long-term, the Company expects overall electric demand to be positively impacted by increased electrification trends, including electric vehicle adoption, as a means to address economy-wide carbon emission concerns and changing customer conservation patterns. MISO and NERC have recently announced concerns with reliability of the electric grid due to capacity shortages, which has resulted from rapid expansion of renewables and rapid reduction of baseload resources such as coal, while load growth has increased faster than expected. MISO received FERC approval of a seasonal resource adequacy construct, or accreditation process, versus the previous annual summer peak capacity requirement process. The new construct will include a higher planning reserve margin in winter, spring and fall and a higher Coincident Load Factor for Montana-Dakota in the winter season. This is a change from the current summer requirement only process. These changes have not required Montana-Dakota to obtain additional accredited seasonal capacity but additional future accreditation process changes could impact the Company and result in increased costs to produce electricity. The Company will continue to monitor the progress of these changes and assess the potential impacts they may have on its stakeholders, business processes, results of operations, cash flows and disclosures.

Revenues are impacted by both customer growth and usage, the latter of which is primarily impacted by weather, as well as impacts associated with commercial and industrial slow-downs, including economic recessions, and energy efficiencies. Very cold winters increase demand for natural gas and to a lesser extent, electricity, while warmer than normal summers increase demand for electricity, especially among residential and commercial customers. Average consumption among both electric and natural gas customers has tended to decline as more efficient appliances and furnaces are installed, and as the Company has implemented conservation programs. Natural gas weather normalization and decoupling mechanisms in certain jurisdictions have been implemented to largely mitigate the effect that would otherwise be caused by variations in volumes sold to these customers due to weather and changing consumption patterns on the Company's distribution margins, as further discussed in Items 1 and 2 - Business Properties.

In December 2022 and January 2023, natural gas prices significantly increased across the Pacific Northwest from multiple price-pressuring events including wide-spread below-normal temperatures; higher natural gas consumption; reduced natural gas flows due to pipeline constraints, including maintenance in West Texas; and historically low regional natural gas storage levels. These higher natural gas prices impacted both Intermountain and Cascade, both of which initiated $125.0 million and $150.0 million in early 2023, respectively, of short-term debt to finance the increased natural gas costs. Intermountain filed an out of cycle purchased gas adjustment effective February 1, 2023, to start recovering the higher prices. For a discussion of the Company's most recent cases by jurisdiction, see Item 8 - Note 20.

The Company continues to proactively monitor and work with its manufacturers to reduce the effects of increased pricing and lead times on delivery of certain raw materials and equipment used in electric generation, transmission and distribution system and natural gas pipeline projects. Long lead times are attributable to increased demand for steel products from pipeline companies as they continue pipeline system safety and integrity replacement projects driven by PHMSA regulations, as well as delays in the manufacturing and shipping of electrical equipment as a result of the lingering effects of the COVID-19 pandemic, staffing shortages across multiple industries and global conflicts. While not material, these segments have experienced delays and inflationary pressures, including increased costs related to purchased natural gas and capital expenditures. The Company has been able to minimize the effects by working closely with suppliers or obtaining additional suppliers, as well as modifying project plans to accommodate extended lead times and increased costs. The Company expects these delays and inflationary pressures to continue.

The ability to grow through acquisitions is subject to significant competition and acquisition premiums. In addition, the ability of the segments to grow their service territory and customer base is affected by regulatory constraints, the economic environment of the markets served and competition from other energy providers and fuels. As the industry continues to expand the use of renewable energy sources, the need for additional transmission infrastructure is growing. On July 25, 2022, as part of its long range transmission plan, MISO announced approval of 18 transmission projects totaling $10.3 billion of investments in MISO's midwest subregion, of which Montana-Dakota is a part. As part of MISO's long range transmission plan, in August 2022, the Company announced its intent to develop, construct and co-own an approximately 95 mile 345 kV transmission line with Otter Tail Power Company in central North Dakota. The construction of new electric generating facilities, transmission lines and other service facilities is subject to increasing costs and lead times, extensive permitting procedures, and federal and state legislative and regulatory initiatives, which may necessitate increases in electric energy prices.

Earnings overview - The following information summarizes the performance of the electric segment.

Years ended December 31,	**2022**	2021	2020	2022 vs. 2021 Variance	2021 vs. 2020 Variance
		(In millions)			
Operating revenues	**$ 377.1**	$ 349.6	$ 332.0	8 %	5 %
Operating expenses:					
Electric fuel and purchased power	**92.0**	74.1	66.9	24 %	11 %
Operation and maintenance	**120.7**	124.9	121.3	(3)%	3 %
Depreciation, depletion and amortization	**67.8**	66.8	63.0	1 %	6 %
Taxes, other than income	**16.9**	17.5	17.4	(3)%	1 %
Total operating expenses	**297.4**	283.3	268.6	5 %	5 %
Operating income	**79.7**	66.3	63.4	20 %	5 %
Other income	**.5**	4.6	7.2	(89)%	(36)%
Interest expense	**28.5**	26.7	26.7	7 %	— %
Income before income taxes	**51.7**	44.2	43.9	17 %	1 %
Income tax benefit	**(5.4)**	(7.7)	(11.7)	(30)%	(34)%
Net income	**$ 57.1**	$ 51.9	$ 55.6	10 %	(7)%

Operating statistics

	2022	2021	2020
Revenues (millions)			
Retail sales:			
Residential	**$ 135.4**	$ 123.0	$ 122.6
Commercial	**142.7**	133.3	131.2
Industrial	**43.0**	40.5	36.7
Other	**7.3**	6.8	6.6
	328.4	303.6	297.1
Transportation and other	**48.7**	46.0	34.9
	$ 377.1	$ 349.6	$ 332.0
Volumes (million kWh)			
Retail sales:			
Residential	**1,226.4**	1,164.8	1,170.9
Commercial	**1,437.7**	1,433.0	1,419.4
Industrial	**596.1**	589.4	532.1
Other	**83.7**	84.4	82.1
	3,343.9	3,271.6	3,204.5
Average cost of electric fuel and purchased power per kWh	**$ .026**	$ .021	$ .019

2022 compared to 2021 Electric earnings increased $5.2 million as a result of:

- Revenue increased $27.5 million.
  - Largely attributable to:
    - Higher fuel and purchased power costs of $17.9 million recovered in customer rates and offset in expense, as described below.
    - Interim rate relief in North Dakota of $5.0 million.
    - Higher net transmission revenues of $3.9 million, largely from increased investment, and higher transmission interconnect upgrades of $800,000.
    - Higher retail sales volumes of 2.2 percent, primarily to residential customers, largely due to colder weather in the first and fourth quarters of the year.
  - Partially offset by:
    - Lower renewable tracker revenues associated with higher production tax credits offset in expense, as described below.
    - Lower per unit average rates of $1.0 million related to block rates in certain jurisdictions.
- Electric fuel and purchased power increased $17.9 million.
  - Primarily the result of $17.4 million higher commodity price, including higher recovery of fuel clause adjustments, and increased retail sales volumes.
- Operation and maintenance decreased $4.2 million.
  - Primarily due to:
    - Decreased payroll-related costs, largely $2.8 million related to the Heskett Station and Lewis & Clark Station plant closures and lower incentive accruals of $1.9 million.
    - Reduced materials costs and contract services from the Heskett Station and Lewis & Clark Station plant closures.
    - Reduced costs due to the absence of the Big Stone Station outage in 2021.
  - Partially offset by increased contract services associated with a planned outage at Coyote Station of $2.6 million.
- Depreciation, depletion and amortization increased $1.0 million, largely resulting from increased property, plant and equipment balances placed in service, mostly related to growth and replacement projects.
- Taxes, other than income decreased $600,000, largely as a result of lower coal conversion taxes in certain jurisdictions.
- Other income decreased $4.1 million, primarily due to lower returns on the Company's nonqualified benefit plan investments of $4.6 million, as discussed in Note 8, partially offset by higher AFUDC equity largely due to higher rates.
- Interest expense increased $1.8 million, largely resulting from $3.2 million due to higher long-term debt balances, partially offset by higher AFUDC debt largely due to higher rates.
- Income tax benefit decreased $2.3 million.
  - Largely due to:
    - Higher income taxes of $1.8 million related to higher taxable income.
    - Higher permanent tax adjustments and decreased excess deferred amortization.
  - Partially offset by higher production tax credits of $1.4 million driven by higher wind production.

2021 compared to 2020 Electric earnings decreased $3.7 million as a result of:

- Revenue increased $17.6 million
  - Higher fuel and purchased power costs of $7.2 million recovered in customer rates and offset in expense, as described below.
  - Higher transmission revenues of $3.3 million.
  - Higher transmission interconnect upgrades of $2.4 million.
  - Higher MISO revenue of $2.0 million.
  - Higher demand revenues of $1.5 million.
  - Increased retail sales volumes of 2.1 percent, largely as a result of increased industrial and commercial sales volumes, offset in part by lower residential sales volumes, as the impacts of the COVID-19 pandemic began to reverse and businesses reopened.
- Electric fuel and purchased power increased $7.2 million attributable to higher MISO costs as a result of increased energy costs, partially offset by decreased fuel costs associated with the Lewis & Clark Station plant closure.
- Operation and maintenance expense increased $3.6 million.
  - Primarily the result of:
    - Higher planned maintenance outage costs of $2.1 million at Big Stone Station and $800,000 higher maintenance fees at Thunder Spirit.
    - Higher other miscellaneous expenses.
  - Partially offset by lower payroll-related costs of $700,000, which includes lower employee incentive accruals, offset in part by higher health care costs.
- Depreciation, depletion and amortization increased $3.8 million largely resulting from:
  - Increased property, plant and equipment balances, primarily related to transmission projects placed in service.
  - Increased amortization of plant retirement and closure costs of $1.7 million recovered in operating revenues, as discussed in Item 8 - Note 6.
- Taxes, other than income was comparable to the same period in the prior year.

- Other income decreased $2.6 million.
  - Primarily due to:
    - The absence of an out-of-period adjustment of $2.5 million in 2020 as a result of previously overstated benefit plan expenses.
    - Lower returns on the Company's nonqualified benefit plan investments of $1.3 million.
  - Partially offset by increased interest income associated with higher contributions in aid of construction.

- Interest expense was comparable to the same period in the prior year.

- Income tax benefit decreased $4.0 million largely resulting from:
  - Lower production tax credits of $2.1 million related to the expiration of the 10-year credit-qualifying period on certain facilities and less wind generation.
  - Lower excess deferred tax amortization.

Earnings overview - The following information summarizes the performance of the natural gas distribution segment.

Years ended December 31,	**2022**	2021	2020	2022 vs. 2021 Variance	2021 vs. 2020 Variance
		(In millions)			
Operating revenues	**$ 1,273.8**	$ 971.9	$ 848.2	31 %	15 %
Operating expenses:					
Purchased natural gas sold	**816.1**	542.0	448.1	51 %	21 %
Operation and maintenance	**205.3**	194.1	185.4	6 %	5 %
Depreciation, depletion and amortization	**89.4**	86.0	84.6	4 %	2 %
Taxes, other than income	**71.1**	60.6	57.0	17 %	6 %
Total operating expenses	**1,181.9**	882.7	775.1	34 %	14 %
Operating income	**91.9**	89.2	73.1	3 %	22 %
Other income	**3.3**	8.1	13.5	(59)%	(40)%
Interest expense	**42.2**	37.3	36.8	13 %	1 %
Income before income taxes	**53.0**	60.0	49.8	(12)%	20 %
Income tax expense	**7.8**	8.4	5.8	(7)%	45 %
Net income	**$ 45.2**	$ 51.6	$ 44.0	(12)%	17 %

Operating statistics

	2022	2021	2020
Revenues (millions)			
Retail sales:			
Residential	**$ 715.5**	$ 548.1	$ 480.5
Commercial	**450.9**	330.4	281.2
Industrial	**41.5**	31.1	26.2
	1,207.9	909.6	787.9
Transportation and other	**65.9**	62.3	60.3
	$ 1,273.8	$ 971.9	$ 848.2
Volumes (MMdk)			
Retail sales:			
Residential	**74.8**	65.6	65.5
Commercial	**51.0**	44.7	44.2
Industrial	**5.4**	5.0	4.8
	131.2	115.3	114.5
Transportation sales:			
Commercial	**2.0**	1.9	2.0
Industrial	**165.7**	172.5	158.0
	167.7	174.4	160.0
Total throughput	**298.9**	289.7	274.5
Average cost of natural gas per dk	**$ 6.22**	$ 4.70	$ 3.91

2022 compared to 2021: Natural gas distribution earnings decreased $6.4 million as a result of:

- Revenue increased $301.9 million, largely from:
  - Higher purchased natural gas sold of $273.3 million recovered in customer rates that was offset in expense, as described below.
  - Higher retail sales volumes of 13.7 percent across all customer classes due to colder weather, partially offset by weather normalization and decoupling mechanisms in certain jurisdictions.
  - Higher revenue-based taxes recovered in rates of $10.1 million that were offset in expense, as described below.
  - Approved rate relief of $3.6 million in certain jurisdictions and higher pipeline replacement mechanisms of $1.8 million.
- Purchased natural gas sold increased $274.1 million, primarily due to:
  - Higher natural gas costs as a result of higher market prices of $198.1 million, including the higher recovery of purchase gas adjustments related to the February 2021 cold weather event and the 2018 Enbridge pipeline rupture.
  - Higher volumes of natural gas purchased due to increased retail sales volumes.
  - Purchased natural gas sold includes the disallowance of $845,000 ordered by the MNPUC, as discussed in Note 20.
- Operation and maintenance increased $11.2 million, primarily due to:
  - Higher contract services of $6.4 million, primarily higher subcontractor costs.
  - Higher payroll-related costs, including higher straight-time payroll of $4.7 million, partially offset by lower incentive accruals of $3.3 million.
  - Higher other costs, partially resulting from inflation, including higher expected credit losses of $1.8 million from higher receivables balances associated with colder weather and higher gas costs; higher software costs of $1.6 million; higher vehicle fuel cost of $1.3 million; and higher office, travel, materials and other miscellaneous employee costs.
- Depreciation, depletion and amortization increased $3.4 million.
  - Largely from increased property, plant and equipment balances from growth and replacement projects placed in service.
  - Partially offset by decreased depreciation rates in certain jurisdictions of $1.0 million.
- Taxes, other than income increased $10.5 million, largely resulting from higher revenue-based taxes which are recovered in rates.
- Other income decreased $4.8 million primarily related to lower returns on the Company's nonqualified benefit plan investments of $7.0 million, as discussed in Note 8, partially offset by increased interest income.
- Interest expense increased $4.9 million, primarily from higher long-term debt balances and interest rates, partially offset by higher AFUDC debt largely due to higher rates.
- Income tax expense decreased $600,000 due to lower income taxes of $1.5 million related to lower taxable income, partially offset by higher permanent tax adjustments.

2021 compared to 2020 Natural gas distribution earnings increased $7.6 million as a result of:

- Revenue increased $123.7 million.
  - Largely as a result of:
    - Higher purchased natural gas sold of $93.9 million recovered in customer rates and was offset in expense, as described below.
    - Approved rate relief in certain jurisdictions of $15.9 million.
    - Increased retail sales volumes of 0.7 percent across all customer classes, including the benefit of weather normalization and decoupling mechanisms in certain jurisdictions.
    - Increased transportation volumes of 9 percent, primarily to electric generation customers.
    - Higher revenue-based taxes recovered in rates of $2.3 million that were offset in expense, as described below.
    - Higher non-regulated project revenues of $1.7 million.
    - Increased basic service charges due to customer growth and increased per unit average rates of $1.5 million each.
- Purchased natural gas sold increased $93.9 million, primarily due to higher natural gas costs as a result of higher market prices.
- Operation and maintenance increased $8.7 million.
  - Primarily due to:
    - Higher payroll-related costs of $4.3 million, largely related to health care costs and straight-time payroll.
    - Decreased credits of $2.4 million for costs associated with the installation of meters partially from delaying meter replacements for safety measures implemented as a result of the COVID-19 pandemic.
    - Higher expenses for materials, new software, insurance and vehicle fuel.
  - Partially offset by:
    - The absence of the write-off of an abandoned project in the third quarter of 2020 for $1.2 million.
    - Decreased bad debt expense of $1.0 million as the impacts of the COVID-19 pandemic began to subside.
- Depreciation, depletion and amortization increased $1.4 million.
  - Largely from increased property, plant and equipment balances from growth and replacement projects placed in service.
  - Partially offset by decreased depreciation rates in certain jurisdictions of $4.0 million.

- Taxes, other than income increased $3.6 million resulting from:
    - Higher revenue-based taxes of $2.3 million, which are recovered in rates.
    - Higher property taxes in certain jurisdictions of $700,000.
    - Higher payroll taxes driven by increased payroll-related costs.
- Other income decreased $5.4 million primarily related to:
    - The absence of an out-of-period adjustment of $4.4 million in 2020 as a result of previously overstated benefit plan expenses.
    - Decreased interest income related to the recovery of purchased gas cost adjustment balances in certain jurisdictions.
- Interest expense increased $500,000, primarily from lower AFUDC borrowed.
- Income tax expense increased $2.6 million due to higher income before income taxes.

Outlook In 2022, the Company experienced rate base growth of 7.8 percent and expects these segments will grow rate base by approximately 6 percent to 7 percent annually over the next five years on a compound basis. Operations are spread across eight states where the Company expects customer growth to be higher than the national average. In 2022 and 2021, these segments experienced retail customer growth of approximately 1.6 percent and 1.7 percent, respectively, and the Company expects customer growth to continue to average 1 percent to 2 percent per year. This customer growth, along with system upgrades and replacements needed to supply safe and reliable service, will require investments in new and replacement electric and natural gas systems.

These segments are exposed to energy price volatility and may be impacted by changes in oil and natural gas exploration and production activity. Rate schedules in the jurisdictions in which the Company's natural gas distribution segment operates contain clauses that permit the Company to file for rate adjustments for changes in the cost of purchased natural gas. Although changes in the price of natural gas are passed through to customers and have minimal impact on the Company's earnings, the natural gas distribution segment's customers benefit from lower natural gas prices through the Company's utilization of storage and fixed price contracts. In 2022, the Company experienced increased natural gas prices across its service areas and more recently has seen higher natural gas prices in the Pacific Northwest, as previously discussed in Strategy and Challenges. As a result, the Company has filed an out-of-cycle cost of gas adjustment in Idaho to assist in the timely recovery of these costs. See Note 20 for additional details. The Company will continue to monitor natural gas prices, as well as oil and natural gas production levels.

In February 2019, the Company announced the retirement of three aging coal-fired electric generating units. The Company ceased operations of Unit 1 at Lewis & Clark Station in Sidney, Montana, in March 2021 and Units 1 and 2 at Heskett Station near Mandan, North Dakota, in February 2022. In addition, in May 2022, the Company began construction of Heskett Unit 4, an 88-MW simple-cycle natural gas-fired combustion turbine peaking unit at the existing Heskett Station near Mandan, North Dakota, with an expected in service date in the summer of 2023.

The Company is one of four owners of Coyote Station and cannot make a unilateral decision on the plant's future; therefore, the Company could be negatively impacted by decisions of the other owners. In September 2021, Otter Tail Power Company filed its 2022 Integrated Resource Plan in Minnesota and North Dakota, which included its intent to start the process of withdrawal from its 35 percent ownership interest in Coyote Station with an anticipated exit from the plant by December 21, 2028. In October 2022, Otter Tail Power Company requested permission from the MNPUC to extend the deadline for its Integrated Resource Plan with the intent to update its modeling in light of recent developments in the industry, including increased capacity requirements in MISO. Otter Tail Power Company's extension was granted by the MNPUC on November 1, 2022, with revised modeling due March 31, 2023. The joint owners continue to collaborate in analyzing data and weighing decisions that impact the plant and its employees as well as each company's customers and communities served. Further state implementation of pollution control plans to improve visibility at Class I areas, such as national parks, under the EPA's Regional Haze Rule could require the owners of Coyote Station to incur significant new costs. If the owners decide to incur such costs, the costs could, dependent on determination by state regulatory commissions on approval to recover such costs from customers, negatively impact the Company's results of operations, financial position and cash flows. The NDDEQ submitted its state implementation plan to the EPA in August 2022 and expects a decision on the plan sometime in 2023. The plan, as submitted by the NDDEQ, does not require additional controls for any units in North Dakota, including Coyote Station.

Legislation and rulemaking The Company continues to monitor legislation and rulemaking related to clean energy standards that may impact its segments. Below are some of the specific legislative actions the Company is monitoring.

- The current presidential administration is considering changes to the federal Clean Air Act, some of which were amended by the previous presidential administration. The content and impacts of the changes under consideration are uncertain and the Company continues to monitor for potential actions by the EPA.
- In Oregon, the Climate Protection Program Rule was approved in December 2021, which requires natural gas companies to reduce GHG emissions 50 percent below the baseline by 2035 and 90 percent below the baseline by 2050, which may be achieved through surrendering emissions allowances, investing in additional customer conservation and energy efficiency programs, purchasing community climate investment credits, and purchasing low carbon fuels such as renewable natural gas. The Company expects the compliance costs for these regulations to be recovered through customer rates. For more information about the anticipated compliance costs, Items 1 and 2 - Business Properties. Cascade's draft 2023 Oregon integrated resource plan projects customer bills could increase by about 100 percent by 2035 compared with costs included in bills today and by about 300 percent by 2050 as a result of the legislation. On September 30, 2022, the Company filed a request for the use of deferred accounting for costs related to the rule and began deferring those costs. The Company, along with the other two local natural gas distribution companies in Oregon, filed a lawsuit on March 18, 2022, challenging the Climate Protection

Program Rule. The lawsuit was filed on behalf of customers as the Company does not believe the rule accomplishes environmental stewardship in the most effective and affordable way possible.
- In Washington, the Climate Commitment Act signed into law in May 2021 requires natural gas distribution companies to reduce overall GHG emissions 45 percent below 1990 levels by 2030, 70 percent below 1990 levels by 2040 and 95 percent below 1990 levels by 2050, which may be achieved through increased energy efficiency and conservation measures, purchased emission allowances and offsets, and purchases of low carbon fuels. As directed by the Climate Commitment Act, in September 2022, the Washington DOE published its final rule on the Climate Commitment Program. The rule was effective on October 30, 2022 and emissions compliance began on January 1, 2023. The Company has begun reviewing compliance options and expects the compliance costs for these regulations will be recovered through customer rates. For more information about the anticipated compliance costs, see Items 1 and 2 - Business Properties. Cascade's draft 2023 Washington integrated resource plan projects customer bills could increase by about 23 percent by 2035 compared with costs included in bills today and by about 78 percent by 2050 as a result of the legislation. On October 14, 2022, the Company filed a request for the use of deferred accounting for costs related to the rule and began deferring those costs.
- On April 22, 2022, the Washington State Building Code Council approved revisions to the state's commercial energy code that will significantly limit the use of natural gas for space and water heating in new and retrofitted commercial and multifamily buildings and proposed the review of similar restrictions in the future for residential buildings. On November 4, 2022, the Washington State Building Code Council adopted new residential codes requiring gas or electric heat pumps for most new space and water heating installations. The Company continues to assess the impact of these revisions.
- The Company has reviewed the income tax provisions of the IRA signed into law in August 2022, and the Company will continue to evaluate whether any of the new or renewed energy tax credits will provide a benefit.

Pipeline

Strategy and challenges The pipeline segment provides natural gas transportation, underground storage and non-regulated cathodic protection services, as discussed in Items 1 and 2 - Business Properties. The segment focuses on utilizing its extensive expertise in the design, construction and operation of energy infrastructure and related services to increase market share and profitability through optimization of existing operations, organic growth and investments in energy-related assets within or in close proximity to its current operating areas. The segment focuses on the continual safety and reliability of its systems, which entails building, operating and maintaining safe natural gas pipelines and facilities. The segment continues to evaluate growth opportunities including the expansion of natural gas facilities; incremental pipeline projects; and expansion of energy-related services leveraging on its core competencies. In support of this strategy, the North Bakken Expansion project in western North Dakota was placed in service in February of 2022. The project has capacity to transport 250 MMcf of natural gas per day and can be increased to 625 MMcf per day with additional compression. In addition, the Line Section 7 Expansion project was placed in service in August of 2022 and increased system capacity by 6.7 MMcf per day.

The segment is exposed to energy price volatility which is impacted by the fluctuations in pricing, production and basis differentials of the energy market's commodities. Legislative and regulatory initiatives on increased pipeline safety regulations and environmental matters such as the reduction of methane emissions could also impact the price and demand for natural gas.

The pipeline segment is subject to extensive regulation related to certain operational and environmental compliance, cybersecurity, permit terms and system integrity. The Company continues to actively evaluate cybersecurity processes and procedures, including changes in the industry's cybersecurity regulations, for opportunities to further strengthen its cybersecurity protections. Implementation of enhancements and additional requirements is ongoing. The segment reviews and secures existing permits and easements, as well as new permits and easements as necessary, to meet current demand and future growth opportunities on an ongoing basis.

The Company has continued to actively manage the national supply chain challenges being faced by working with its manufacturers and suppliers to help mitigate some of these risks on its business. The segment regularly experiences extended lead times on raw materials that are critical to the segment's construction and maintenance work which could delay maintenance work and construction projects potentially causing lost revenues and/or increased costs. The Company is partially mitigating these challenges by planning for extended lead times further in advance. The segment is also currently experiencing inflationary pressures with increased raw material costs. The Company expects supply chain challenges and inflationary pressures to continue in 2023.

The segment focuses on the recruitment and retention of a skilled workforce to remain competitive and provide services to its customers. The industry in which it operates relies on a skilled workforce to construct energy infrastructure and operate existing infrastructure in a safe manner. A shortage of skilled personnel can create a competitive labor market which could increase costs incurred by the segment. Competition from other pipeline companies can also have a negative impact on the segment.

Earnings overview - The following information summarizes the performance of the pipeline segment.

Years ended December 31,	**2022**	2021	2020	2022 vs. 2021 Variance	2021 vs. 2020 Variance
		(In millions)			
Operating revenues	**$ 155.6**	$ 142.6	$ 143.9	9 %	(1)%
Operating expenses:					
Operation and maintenance	**60.9**	61.3	59.9	(1)%	2 %
Depreciation, depletion and amortization	**26.9**	20.5	21.7	31 %	(6)%
Taxes, other than income	**12.3**	12.7	12.9	(3)%	(2)%
Total operating expenses	**100.1**	94.5	94.5	6 %	— %
Operating income	**55.5**	48.1	49.4	15 %	(3)%
Other income	**1.3**	9.4	2.9	(86)%	224 %
Interest expense	**11.3**	7.0	7.6	61 %	(8)%
Income before income taxes	**45.5**	50.5	44.7	(10)%	13 %
Income tax expense	**10.2**	9.6	7.7	6 %	25 %
Net income	**$ 35.3**	$ 40.9	$ 37.0	(14)%	11 %

Operating statistics

	2022	2021	2020
Transportation volumes (MMdk)	**482.9**	471.1	438.6
Natural gas gathering volumes (MMdk)	**—**	—	8.6
Customer natural gas storage balance (MMdk):			
Beginning of period	**23.0**	25.5	16.2
Net injection (withdrawal)	**(1.8)**	(2.5)	9.3
End of period	**21.2**	23.0	25.5

2022 compared to 2021 Pipeline earnings decreased $5.6 million as a result of:

- Revenues increased $13.0 million.
  - Driven by increased transportation volume revenues of $16.4 million, largely due to the North Bakken Expansion project placed in service in February 2022.
  - Partially offset by:
    - Lower non-regulated project revenues of $2.3 million.
    - Lower transmission rates due to expired negotiated contracts converted to tariff rates.
- Operation and maintenance decreased $400,000.
  - Primarily due to:
    - Lower payroll-related costs of $2.2 million, largely related to lower incentive accruals and benefit-related costs.
    - Lower non-regulated project costs of $1.3 million directly associated with lower non-regulated project revenues, as previously discussed.
  - Partially offset by higher legal, maintenance materials and contract services.
- Depreciation, depletion and amortization increased $6.4 million due to increased property, plant and equipment balances, largely related to the North Bakken Expansion project.
- Taxes, other than income decreased $400,000 resulting from lower property taxes of $700,000 in Montana, partially offset by higher property taxes in North Dakota.
- Other income decreased $8.1 million, primarily due to:
  - Lower AFUDC of $7.8 million as a result of the completion of the North Bakken Expansion project placed in service in February 2022.
  - Lower returns on the Company's nonqualified benefit plan investments, as discussed in Note 8.
- Interest expense increased $4.3 million, resulting from interest associated with higher debt balances to fund capital expenditures and lower AFUDC as a result of the North Bakken Expansion project placed in service in February 2022.
- Income tax expense increased $600,000, largely a result of a reduction in tax credits, partially offset by lower income before income taxes.

2021 compared to 2020 Pipeline earnings increased $3.9 million as a result of:

- Revenues decreased $1.3 million.
  - Primarily decreased gathering revenues of $4.9 million due to the sale of the Company's natural gas gathering assets in 2020.
  - Partially offset by:
    - Increased transportation volumes and demand revenue of $1.8 million largely from organic growth projects, as previously discussed, and short-term discounted contracts.
    - Increased non-regulated project revenues of $1.4 million.
- Operation and maintenance increased $1.4 million due to:
  - The absence of the gain on sale of the Company's natural gas gathering assets of $1.5 million in 2020, offset partially by lower operating expenses related to the natural gas gathering assets.
  - Partially offset by lower payroll-related costs.
- Depreciation, depletion and amortization decreased $1.2 million.
  - Primarily related to lower expense of $1.6 million due to the sale of the Company's natural gas gathering assets in 2020, as previously discussed.
  - Slightly offset by increased property, plant and equipment balances related to organic growth projects.
- Taxes, other than income was comparable to the same period in the prior year.
- Other income increased $6.5 million.
  - Primarily due to:
    - Higher AFUDC of $7.3 million for the construction of the North Bakken Expansion project.
    - The absence of the write-off of unrecovered gas costs and project expenses of $1.2 million in 2020.
  - Partially offset by:
    - The absence of a positive impact of $700,000 related to the sale of the Company's regulated gathering assets in 2020.
    - The absence of an out-of-period adjustment of $500,000 in 2020 as a result of previously overstated benefit plan expenses.
    - Lower returns on the Company's nonqualified benefit plan investments.
- Interest expense decreased $600,000.
  - Primarily due to:
    - Higher AFUDC of $1.5 million for the construction of the North Bakken Expansion project.
    - Lower average interest rates.
  - Partially offset by higher debt balances.
- Income tax expense increased $1.9 million.
  - Largely a result of:
    - Higher income before income taxes.
    - The absence of the reversal of excess deferred taxes of $1.5 million associated with the sale of the Company's gas gathering assets in 2020.
  - Partially offset by permanent tax adjustments and an energy efficiency tax benefit.

Outlook The Company continues to monitor and assess the potential impacts of two FERC draft policy statements issued in the first quarter of 2022. One is the Updated Certificate of Policy Statement, which describes how the FERC will determine whether a new interstate natural gas transportation project is required by public convenience and necessity. It includes increased focus on a project's purpose and need and the environmental impacts; as well as impacts on landowners and environmental justice communities. The second draft policy statement, the Interim GHG Policy Statement, explains how the FERC will assess the impacts of natural gas infrastructure projects on climate change in its reviews under the National Environmental Policy Act and Natural Gas Act.

The Company has reviewed the income tax provisions of the IRA signed into law in August 2022 and does not expect any material income tax benefits as a result. The Company has also evaluated the impacts of the methane emissions charge imposed under the IRA legislation and does not expect any material fees given the current GHG reporting thresholds. The Company continues to monitor, evaluate and implement additional GHG emissions reduction strategies, including increased monitoring frequency and emission source control technologies to minimize potential risk.

The EPA recently proposed additional rules to update, strengthen and expand standards intended to significantly reduce GHG emissions and other air pollutants from the oil and natural gas industries. The standards will apply to natural gas compressors, pneumatic controllers and pumps, fugitive emissions components and super-emitter events. The EPA projects the final rules will be issued in August 2023. Additionally, the EPA anticipates revising the current GHG reporting rules to incorporate provisions in the IRA. These revisions are anticipated to be issued in April 2023. The Company continues to monitor and assess the proposed rules and the potential impacts they may have on its business processes, current and future projects, results of operations and disclosures.

The Company has continued to experience the effect of associated natural gas production in the Bakken, which has provided opportunities for organic growth projects and increased demand. The completion of organic growth projects has contributed to higher volumes of natural gas the Company transports through its system. Associated natural gas production in the Bakken fell during the COVID-19 pandemic delaying previously forecasted production growth. Natural gas production has rebounded to pre-pandemic levels and drilling rig activities have increased, and the Company expects continued gradual increases over the next 2 years. The production delay, along with long-term contractual commitments on the North Bakken Expansion project placed in service in February 2022, has negatively impacted customer renewals of certain contracts. Bakken natural gas production outlook remains positive with continued growth expected due to new oil wells and increasing gas to oil ratios.

Increases in national and global natural gas supply has moderated pressure on natural gas prices and price volatility. While the Company believes there will continue to be varying pressures on natural gas production levels and prices, the long-term outlook for natural gas prices continues to provide growth opportunity for industrial supply-related projects and seasonal pricing differentials provide opportunities for storage services.

The Company continues to focus on improving existing operations and growth opportunities through organic projects in all areas in which it operates, which includes additional projects with local distribution companies, Bakken area producers and industrial customers in various stages of development.

In July 2021, the Company announced plans for a natural gas pipeline expansion project in eastern North Dakota. The Wahpeton Expansion project consists of approximately 60 miles of pipe and ancillary facilities and is designed to increase capacity by 20 MMcf per day, which is supported by long-term customer agreements with Montana-Dakota and its utility customers. Construction is expected to begin in early 2024, depending on regulatory approvals, with an anticipated completion date later in 2024. On May 27, 2022, the Company filed with FERC its application for the project and received FERC's draft environmental impact statement for the project on November 3, 2022. In accordance with the FERC schedule for environmental review on the project, the final environmental impact statement is planned to be available in April 2023.

On September 19, 2022, the Company filed with the FERC its prior notice application for its 2023 Line Section 27 Expansion project. This project consists of a new compressor station and ancillary facilities and is designed to increase capacity by 175 MMcf per day, which is supported by a long-term customer agreement. Construction is expected to begin in early 2023, pending regulatory approvals, with an anticipated completion date in late 2023.

On December 22, 2022, the Company filed with the FERC its prior notice application for its Grasslands South Expansion project. This project consists of approximately 15 miles of pipe in western North Dakota, utilizing existing capacity on its Grasslands Subsystem to a new connection with Big Horn Gas Gathering, LLC in northeastern Wyoming and ancillary facilities in North Dakota and Wyoming. A long-term customer agreement supports a design for incremental capacity of 94 MMcf per day. Construction is expected to begin in the second quarter of 2023, pending regulatory approvals, with an anticipated completion date in late 2023.

In addition, the Company has entered into long-term customer agreements for the construction of a fourth growth project with incremental natural gas design capacity anticipated to be 25 MMcf per day. The project is dependent on regulatory approvals and anticipated to be completed in 2023. See Capital Expenditures within this section for additional information on the expenditures related to these projects.

Construction Materials and Contracting

Strategy and challenges The segment is a leading aggregates-based construction materials and contracting services provider in the United States, as discussed in Items 1 and 2 - Business Properties. The segment focuses on continued growth and maximizing its vertical integration, leveraging its core values to be a supplier of choice in all its markets. The segment is also focused on its commitment to its employees, customers and communities by operating with integrity and always striving for excellence; development and recruitment of talented employees; sustainable practices to create value for the communities it serves; being the provider of choice in midsize, high-growth markets; strengthening the long-term, strategic aggregate reserve position through available purchase and/or lease opportunities in existing and new geographies; and enhancing its supply chain to provide reliable, timely and efficient services to its end customers. As previously discussed, the Company is pursuing a tax-free spinoff of the construction materials and contracting segment, and the separation is expected to be complete in the second quarter of 2023.

The segment is one of the leading producers of crushed stone and sand and gravel, and the segment continues to strategically manage its aggregate reserves, as well as take further advantage of being vertically integrated. The segment's vertical integration allows it to manage operations from aggregate mining to final lay-down of concrete and asphalt, with control of and access to permitted aggregate reserves being significant. The Company's aggregate reserves are naturally declining and as a result, the Company seeks permit expansion and acquisition opportunities to replace the reserves.

The segment's management continually monitors its margins and has been proactive in applying strategies to address the inflationary impacts seen across the United States. The Company has increased its product pricing where necessary and continues to implement cost savings initiatives to mitigate these effects on the segment's gross margin. Due to existing contractual provisions, there can be a lag between the announced price increases and the time when they can be fully recognized. The Company will continue to evaluate further price increases on a regular cadence to stay ahead of inflationary pressures and enhance stockholder value.

The segment operates in geographically diverse and competitive markets yet strives to maximize efficiencies, including transportation costs and economies of scale, to maintain strong margins. The segment's margins can experience negative pressure from competition, as well as impacts of the volatility in the cost of raw materials such as fuel, asphalt oil, cement and steel, with fuel and asphalt oil costs having the most significant impact on the segment's recent results. Such volatility and inflationary pressures may continue to have an impact on the segment's margins, including fixed-price construction contracts that are particularly vulnerable to the volatility of energy and material prices. These increases are partially offset by mitigation measures implemented by the Company, including price increases, escalation clauses in contracting services contracts, pre-purchased materials and other cost savings initiatives. While the Company has experienced some supply chain constraints, it continues to have good relationships with its suppliers and has not experienced any material adverse impacts of shortages or delays on materials. Other variables that can impact the segment's margins include adverse weather conditions, the timing of project starts or completions and declines or delays in new and existing projects due to the cyclical nature of the construction industry and governmental infrastructure spending. Accordingly, operating results in any particular period may not be indicative of the results that can be expected for any other period.

As a people first company, the segment continually takes steps to address the challenge of recruitment and retention of employees. In order to help attract new workers to the construction industry and enhance the skills of its current employees, the Company has completed construction of a corporate-wide, state-of-the-art training facility in the Pacific Northwest. The training facility offers hands-on training for heavy equipment operators and truck drivers, as well as leadership and safety training. Trends in the labor market include an aging workforce and availability issues, and most of the markets the segment operates in have experienced labor shortages, largely truck drivers, causing increased labor-related costs and delays or inefficiencies on projects. The new training facility is expected to help address some of these challenges. The Company continues to monitor the labor markets and assess additional opportunities to enhance and support its workforce. Despite these efforts, the Company expects labor costs to continue to increase based on the increased demand for services and, to a lesser extent, the recent escalated inflationary environment in the United States.

Earnings overview - The following information summarizes the performance of the construction materials and contracting segment.

Years ended December 31,	**2022**	2021	2020	2022 vs. 2021 % change	2021 vs. 2020 % change
		(In millions)			
Operating revenues	**$ 2,534.7**	$ 2,228.9	$ 2,178.0	14 %	2 %
Cost of sales:					
Operation and maintenance*	**2,009.6**	1,737.4	1,676.6	16 %	4 %
Depreciation, depletion and amortization	**112.9**	96.8	84.8	17 %	14 %
Taxes, other than income	**51.3**	47.7	46.0	8 %	4 %
Total cost of sales	**2,173.8**	1,881.9	1,807.4	16 %	4 %
Gross profit	**360.9**	347.0	370.6	4 %	(6)%
Selling, general and administrative expense:					
Operation and maintenance*	**155.8**	146.0	146.4	7 %	— %
Depreciation, depletion and amortization	**4.9**	4.2	4.8	17 %	(13)%
Taxes, other than income	**5.9**	5.7	4.9	4 %	16 %
Total selling, general and administrative expense	**166.6**	155.9	156.1	7 %	— %
Operating income	**194.3**	191.1	214.5	2 %	(11)%
Other income (expense)	**(5.4)**	1.3	.8	(515)%	63 %
Interest expense	**30.1**	19.2	20.6	57 %	(7)%
Income before income taxes	**158.8**	173.2	194.7	(8)%	(11)%
Income tax expense	**42.6**	43.4	47.4	(2)%	(8)%
Net income	**$ 116.2**	$ 129.8	$ 147.3	(10)%	(12)%

* The Company identified certain costs that were reclassified from cost of sales to selling, general and administrative expenses in 2021 and 2020 of $57.4 million and $56.5 million, respectively, and had no impact to net income.

Operating statistics	Revenues			Gross profit		
	2022	2021	2020	**2022**	2021	2020
			(In millions)			
Aggregates	**$ 496.6**	$ 444.0	$ 406.6	**$ 69.6**	$ 60.6	$ 62.7
Asphalt	**427.5**	339.8	349.9	**41.7**	40.4	45.5
Ready-mix concrete	**609.5**	584.4	547.0	**85.9**	81.5	74.4
Other products*	**407.3**	344.3	356.3	**63.6**	64.0	82.6
Contracting services	**1,187.7**	1,017.5	1,069.7	**100.1**	100.5	105.4
Intracompany eliminations	**(593.9)**	(501.1)	(551.5)	**—**	—	—
	$ 2,534.7	$ 2,228.9	$ 2,178.0	**$ 360.9**	$ 347.0	$ 370.6

* Other products includes cement, asphalt oil, merchandise, fabric, spreading and other products that individually are not considered to be a major line of business for the segment.

	2022	2021	2020
Sales (thousands):			
Aggregates (tons)	**33,994**	33,518	30,949
Asphalt (tons)	**7,254**	7,101	7,202
Ready-mix concrete (cubic yards)	**4,015**	4,267	4,087
Average sales price:			
Aggregates (per ton)	**$ 14.61**	$ 13.25	$ 13.14
Asphalt (per ton)	**$ 58.93**	$ 47.86	$ 48.58
Ready-mix concrete (per cubic yard)	**$ 151.80**	$ 136.94	$ 133.86

2022 compared to 2021 Construction materials and contracting's earnings decreased $13.6 million as a result of:

- Revenues increased $305.8 million.
  - Primarily the result of increased revenues across all product lines as the business benefited from higher average selling prices of nearly $250 million, largely in response to inflationary pressures.
  - Also impacting materials revenues were:
    - Increased aggregates sales volumes of $10.2 million due mainly to recent acquisitions contributing 2.2 million tons, offset in part by lower volumes in certain states.
    - Increased asphalt sales volumes of $7.2 million from higher demand in California, Minnesota, Montana, North Dakota and Wyoming of $13.7 million, partially offset by lower volumes in Texas due to less available paving work.
    - Lower ready-mix concrete sales volumes of $38.5 million across all regions resulting from lower residential demand and fewer impact projects.
    - Decreased revenues for other products associated with volumes, largely related to asphalt oil.
    - Increased contracting revenues of $170.2 million across most regions as a result of more available agency and commercial work, recent acquisitions contributing $27.9 million and more available paving work in Idaho, Minnesota, Montana, North Dakota and Wyoming. In addition, inflationary pressures led to higher contract values in all regions.
  - These increases were partially offset by an increase in the elimination for internal materials sales used in other products and services.

- Gross profit increased $13.9 million.
  - Primarily the result of higher average selling prices, as previously noted, contributions from recent acquisitions of $12.9 million and increased margins for aggregates and ready-mix concrete as a result of implemented price increases outpacing inflationary pressures.
  - Partially offset by higher operating costs across the business, mostly the result of inflationary pressures. These costs include higher asphalt oil costs of $59.3 million; higher labor costs of $32.0 million; higher fuel costs of $42.6 million; and higher cement costs of $20.7 million.

- Selling, general and administrative expense increased $10.7 million.
  - Largely the result of:
    - Increased payroll-related costs of $11.6 million, partially resulting from inflationary pressures.
    - Increased travel expenses of $2.3 million.
    - Increased office expenses of $1.7 million.
    - Increased professional fees of $1.7 million, partially due to increased legal and audit fees.
    - Increased expected credit losses of $1.4 million related to the absence of recoveries received during 2021.
    - Increased safety and training costs.
  - Offset in part by higher net gains on asset sales of $7.5 million.

- Other income (expense) decreased $6.7 million, primarily resulting from lower returns on the Company's nonqualified benefit plan investments, as discussed in Note 8.

- Interest expense increased $10.9 million, related to higher debt balances to fund recent acquisitions and higher working capital needs, along with higher average interest rates.

- Income tax expense decreased $800,000 as a result of lower income before income taxes.

2021 compared to 2020 Construction materials and contracting's earnings decreased $17.5 million as a result of:

- Revenues increased $50.9 million.
    - Largely the result of:
        - Higher aggregate sales volumes from acquisitions in 2021 contributed $20.1 million and strong demand for airport, commercial and health care work in Oregon added $16.3 million. Also contributing was an additional $1.6 million due to a few large projects in South Dakota. These increases were partially offset by lower volumes in Texas of $2.0 million driven by lower energy-related sales volumes.
        - Higher ready-mix concrete volumes from increased commercial and residential demand in Texas contributed $8.2 million, strong demand in Oregon added $7.8 million and acquisitions in 2021 contributed an additional $4.5 million. Ready-mix concrete revenues also benefited from an increase in average sales price in all regions. These increases were partially offset by decreased sales of $14.8 million due to lower demand in Hawaii as a result of the overall slowdown of the travel industry from COVID-19.
    - Partially offset by:
        - Decreased contracting revenues partially due to less available paving work in certain regions of $60.0 million and the absence of a few large jobs in 2020 of $17.5 million. These decreases were offset in part by strong demand for health care, agency and commercial work in Oregon of $28.8 million.
        - Decreased asphalt volumes primarily due to less available highway paving work in the public sector of $26.2 million in certain regions was partially offset by strong demand in Oregon.

- Gross profit decreased $23.6 million.
    - Primarily due to:
        - Lower gross profit and margins in other product lines, primarily due to higher asphalt oil material costs of $15.1 million, along with repair and maintenance costs of $2.6 million.
        - Higher fuel costs of $13.3 million across all product lines.
        - Lower asphalt gross profit of $5.1 million, largely resulting from less available paving work.
        - Lower contracting services gross profit resulting from less available paving work of $8.6 million, as previously discussed, and the absence of a few large jobs for $5.4 million. Margins were also impacted by higher fuel costs, as previously discussed.
        - Lower aggregates gross profit resulting from reduced work in Hawaii due to the overall slowdown of the travel industry resulting from COVID-19 of $3.9 million, startup costs of $1.3 million associated with new aggregate sites in Texas and $600,000 higher material costs in Alaska. These decreases were partially offset by higher margins due to strong demand in Oregon of $2.1 million and South Dakota of $1.4 million along with the effects of recent acquisitions.
        - Labor constraints, especially truck drivers, which resulted in isolated project delays and staffing inefficiencies across the business.
    - Partially offset by an increase in ready-mix concrete gross profit of $7.1 million due in part to higher average pricing in all regions and higher volumes in most regions.

- Selling, general and administrative expense decreased $200,000.
    - Largely the result of:
        - The recovery of prior bad debt expense of $2.1 million.
        - Higher net gains on asset sales of $1.4 million.
    - Offset in part by:
        - Increased payroll-related costs of $1.6 million, primarily for higher health care costs.
        - Higher acquisition costs of $700,000.
        - An increase in miscellaneous taxes, license and governmental fees.

- Other income increased $500,000, primarily resulting from an out-of-period adjustment in 2020 as a result of previously overstated benefit plan expenses.

- Interest expense decreased $1.4 million.
    - Primarily resulting from lower average interest rates of $2.8 million.
    - Offset in part by higher average debt balances.

- Income tax expense decreased $4.0 million as a result of lower income before income taxes.

Outlook In August 2022, the Company announced its intent to separate this segment into a standalone publicly traded company. The separation is expected to result in two independent, publicly traded companies: (1) MDU Resources Group, Inc., the existing company and (2) Knife River, a construction materials and contracting services company. The separation is expected to be completed in the second quarter of 2023 and is expected to unlock inherent value within the two companies, which each have unique growth prospects and investment opportunities. The Company may, at any time and for any reason until the proposed transaction is complete, abandon the separation or modify or change its terms. For a complete discussion of all of the conditions to and the risks and uncertainties associated with the separation and distribution, see Item 1A - Risk Factors.

Funding for public projects is dependent on federal and state funding, such as appropriations to the Federal Highway Administration. The American Rescue Plan Act enacted in the first quarter of 2021 provides $1.9 trillion in COVID-19 relief funding for states, schools and local governments. States are beginning to move forward with allocating these funds based on federal criteria and state needs, and in some cases, funding of infrastructure projects could positively impact the segment. Additionally, the bipartisan infrastructure proposal, known as the IRA, was enacted in the fourth quarter of 2021 and is providing long-term opportunities by designating $119 billion for the repair and rebuilding of roads and bridges across the Company's footprint. In addition, the IRA provides $369 billion in new funding for clean energy programs. These programs include new tax incentives for solar, battery storage and hydrogen development along with funding to expand the production of electric vehicles and the build out of infrastructure to support electric vehicles. In addition to federal funding, 11 out of the 14 states in which the Company operates have implemented their own funding mechanisms for public projects, including projects related to highways, airports and other public infrastructure. The Company continues to monitor the progress of these legislative items.

The segment's vertically integrated aggregates-based business model provides the Company with the ability to capture margin throughout the sales delivery process. The aggregate products are sold internally and externally for use in other products such as ready-mix concrete, asphaltic concrete and public and private construction markets. The contracting services and construction materials are sold in connection with street, highway and other public infrastructure projects, as well as private commercial, industrial and residential development projects. The public infrastructure projects have traditionally been more stable markets as public funding is more secure during periods of economic decline. The public projects are, however, dependent on federal and state funding such as appropriations to the Federal Highway Administration. Spending on private development is highly dependent on both local and national economic cycles, providing additional sales during times of strong economic cycles and potential for reductions during recessionary periods.

During 2022 and 2021, the Company made strategic purchases and completed acquisitions that support the Company's long-term strategy to expand its market presence in the higher-margin materials markets. The Company continues to evaluate additional acquisition opportunities. For more information on the Company's business combinations, see Item 8 - Note 4. In 2022, the Company is upgrading its prestress facility located in Spokane, Washington. The state-of-the-art facility is expected to be completed during the first half of 2023. The facility is expected to be a platform for growth through improved productivity and quality, which will help meet strong market demand for prefabricated concrete solutions.

The construction materials and contracting segment's backlog remained strong at December 31, 2022, at $935 million, as compared to backlog at December 31, 2021, of $708 million. A significant portion of the Company's backlog at December 31, 2022, relates to publicly funded projects, largely street and highway construction projects, which are primarily driven by public work projects for state departments of transportation. Period over period increases or decreases in backlog cannot be used as an indicator of future revenues or net income. Of the $935 million of backlog at December 31, 2022, the Company expects to complete an estimated $836 million during 2023. While the Company believes the current backlog of work remains firm, prolonged delays in the receipt of critical supplies and materials or continued increases to pricing could result in customers seeking to delay or terminate existing or pending agreements. Factors noted in Item 1A - Risk Factors can cause revenues to be realized in periods and at levels that are different from originally projected.

Construction Services

Strategy and challenges The construction services segment provides electrical and mechanical and transmission and distribution specialty contracting services, as discussed in Items 1 and 2 - Business Properties. The construction services segment focuses on safely executing projects; providing a superior return on investment by building new and strengthening existing customer relationships; ensuring quality service; effectively controlling costs; retaining, developing and recruiting talented employees; growing through organic and strategic acquisition opportunities; and focusing efforts on projects that will permit higher margins while properly managing risk. The growth experienced by the segment in recent years is due in part to the project awards in the markets served and the ability to support national customers in most of the regions in which it operates.

The construction services segment faces challenges, which are not under direct control of the business, in the markets in which it operates, including those described in Item 1A - Risk Factors. These factors, and those noted below, have caused fluctuations in revenues, gross margins and earnings in the past and are likely to cause fluctuations in the future.

- *Revenue mix and impact on margins.* The mix of revenues based on the types of services the segment provides can impact margins as certain industries and services provide higher margin opportunities. Larger or more complex projects typically result in higher margin opportunities since the segment assumes a higher degree of performance risk and there is greater utilization of the segment's resources for longer construction timelines. However, larger or more complex projects have a higher risk of regulatory and seasonal or cyclical delay. Project schedules fluctuate, which can affect the amount of work performed in a given period. Smaller or less complex projects typically have a greater number of companies competing for them, and competitors at times may be more aggressive when pursuing available work. A greater percentage of smaller scale or less complex work in a given period could negatively impact margins due to the inefficiency of transitioning between a greater number of smaller projects versus continuous production on a few larger projects.

- *Project variability and performance.* Margins for a single project may fluctuate period to period due to changes in the volume or type of work performed, the pricing structure under the project contract or job productivity. Productivity and performance on a project can vary period to period based on a number of factors, including unexpected project difficulties; unexpected project site conditions; project location, including locations with challenging operating conditions or difficult geographic characteristics; whether the work is on an open or encumbered right of way; inclement weather or severe weather events; environmental restrictions or regulatory delays; political or legal challenges related to a project; and the performance of third parties. In addition, the type of contract can impact the margin on a project. Under fixed-price contracts, which are more common with larger or more complex projects, the segment assumes risk related to project estimates versus execution. Revenues under this type of contract can vary, sometimes significantly, from original projects due to additional project complexity; timing uncertainty or extended bidding; extended regulatory or permitting processes; and other factors, which can result in a reduction in profit or losses on a project.

- *Subcontractor work and provision of materials.* Some work under project contracts is subcontracted out to other companies and margins on subcontractor work is generally lower than work performed by the Company. Increased subcontractor work in a given period may therefore result in lower margins. In addition, inflationary or other pressures may increase the cost of materials under fixed-price contracts and may result in decreased margins on the project. The Company has worked to implement provisions in project contracts to allow for the pass-through of inflationary costs to customers where feasible and will continue to do so to mitigate the impacts.

The segment's management continually monitors its operating margins and has been proactive in addressing the inflationary impacts seen across the United States. The segment is currently experiencing continued labor constraints and increased fuel and material costs, as well as impacts from delays in the national supply chain. The segment is working with suppliers and providers of goods and services in advance of construction to secure pricing and reduce delays for goods and services. The inflationary costs and national supply chain challenges experienced by the segment have increased costs but have not had significant impacts to the procurement of project materials. Such volatility and inflationary pressures may continue to have an impact on the segment's margins, including fixed-price construction contracts that are particularly vulnerable to the volatility of energy and material prices. These increases are partially offset by mitigation measures implemented by the Company, including escalation clauses in contracts, pre-purchased materials and other cost savings initiatives. The segment also continues recruitment and retention efforts to attract and retain employees. The Company expects these inflationary pressures and national supply chain challenges to continue. Accordingly, operating results in any particular period may not be indicative of the results that can be expected for any other period.

The need to ensure available specialized labor resources for projects also drives strategic relationships with customers and project margins. These trends include an aging workforce and labor availability issues, as well as increasing duration and complexity of customer capital programs. Most of the markets the segment operates in have experienced labor shortages which in some cases have caused increased labor-related costs. The Company continues to monitor the labor markets and expects labor costs to continue to increase based on increases included in the collective bargaining agreements and, to a lesser extent, the recent escalated inflationary environment in the United States. Due to these and other factors, the Company believes overall customer and competitor demand for labor resources will continue to increase.

Earnings overview - The following information summarizes the performance of the construction services segment.

Years ended December 31,	**2022**	2021	2020	2022 vs. 2021 Variance	2021 vs. 2020 Variance
		(In millions)			
Operating revenues	**$ 2,699.2**	$ 2,051.6	$ 2,095.7	32 %	(2)%
Cost of sales:					
Operation and maintenance	**2,325.9**	1,725.5	1,747.5	35 %	(1)%
Depreciation, depletion and amortization	**16.9**	15.8	15.7	7 %	1 %
Taxes, other than income	**80.4**	62.4	74.2	29 %	(16)%
Total cost of sales	**2,423.2**	1,803.7	1,837.4	34 %	(2)%
Gross profit	**276.0**	247.9	258.3	11 %	(4)%
Selling, general and administrative expense:					
Operation and maintenance	**101.5**	92.9	98.1	9 %	(5)%
Depreciation, depletion and amortization	**4.6**	4.5	7.8	2 %	(42)%
Taxes, other than income	**5.3**	4.8	4.8	10 %	— %
Total selling, general and administrative expense	**111.4**	102.2	110.7	9 %	(8)%
Operating income	**164.6**	145.7	147.6	13 %	(1)%
Other income	**7.3**	2.6	2.0	181 %	30 %
Interest expense	**6.3**	3.5	4.1	80 %	(15)%
Income before income taxes	**165.6**	144.8	145.5	14 %	— %
Income tax expense	**40.8**	35.4	35.8	15 %	(1)%
Net income	**$ 124.8**	$ 109.4	$ 109.7	14 %	— %

Operating Statistics

		Revenues			Gross profit	
Business Line	**2022**	2021	2020	**2022**	2021	2020
			(In millions)			
Electrical & mechanical						
Commercial	**$ 1,082.5**	$ 553.2	$ 741.5	**$ 105.2**	$ 59.8	$ 48.4
Industrial	**405.7**	457.5	374.8	**43.4**	51.3	41.3
Institutional	**215.5**	123.1	158.8	**3.8**	6.2	23.8
Renewables	**151.1**	12.3	5.4	**(.6)**	1.2	1.1
Service & other	**143.0**	188.4	121.0	**19.8**	25.1	21.5
	1,997.8	1,334.5	1,401.5	**171.6**	143.6	136.1
Transmission & distribution						
Utility	**645.1**	630.5	592.5	**100.3**	92.4	106.7
Transportation	**72.3**	103.1	111.8	**4.1**	11.9	15.5
	717.4	733.6	704.3	**104.4**	104.3	122.2
Intrasegment eliminations	**(16.0)**	(16.5)	(10.1)	**—**	—	—
	$ 2,699.2	$ 2,051.6	$ 2,095.7	**$ 276.0**	$ 247.9	$ 258.3

2022 compared to 2021 Construction services earnings increased $15.4 million as a result of:

- Revenues increased $647.6 million.
  - Largely due to:
    - Increased electrical and mechanical revenues, partially as a result of inflationary pressures as well as:
      - Higher commercial revenues driven largely by a $251.5 million increase in hospitality projects due to the progress on large projects, a $121.8 million increase in data center projects driven by both the number of and progress on projects and an increase in general commercial projects as a result of project mix and progression of contracts.
      - Higher renewable revenues from the timing of and progress on projects.
      - Higher institutional revenues largely the result of increased activity and progress on projects from education projects of $26.0 million, healthcare projects of $24.1 million and government projects.
    - Increased utility revenues for electrical projects of $37.5 million, underground projects of $24.5 million, distribution projects of $12.7 million, telecommunications projects of $7.0 million and substation projects, with each sector being driven by higher customer demand. These increases were partially offset by lower transmission and storm work projects.
  - Partially offset by:
    - Lower industrial revenues driven by decreased demand for maintenance, high-tech and refinery projects and lower service revenues driven by decreased demand for the repair and maintenance of electrical and mechanical projects.
    - Lower transportation revenues, primarily from lower customer demand for street lighting projects of $39.8 million.
- Gross profit increased $28.1 million.
  - Largely due to the increased electrical and mechanical revenues previously discussed.
  - Partially offset by higher operating costs related to inflationary pressures, including labor, materials and equipment costs.
- Selling, general and administrative expense increased $9.2 million resulting from higher payroll-related costs of $5.7 million, increased expected credit losses of $2.4 million due to changes in estimates during 2021 and higher office expenses.
- Other income increased $4.7 million, primarily related to the Company's joint ventures.
- Interest expense increased $2.8 million due to higher working capital needs and higher interest rates.
- Income tax expense increased $5.4 million as a result of higher income before income taxes.

2021 compared to 2020 Construction services earnings decreased $300,000 as a result of:

- Revenues decreased $44.1 million.
  - Largely due to:
    - The completion of several large commercial projects in early 2021 and 2020 in the Las Vegas market of $129.0 million.
    - Decreased institutional projects of $15.0 million from less available work and the completion of a larger project.
    - The completion of a significant industrial project of $43.0 million.
    - Decreased demand for electric transportation projects which includes traffic signalization and street lighting.
  - Partially offset by:
    - Higher industrial work due to the number of projects awarded and progress on significant projects of $96.0 million.
    - Increased service work of $37.0 million related to the repair and maintenance of electrical, mechanical and fire protection systems.
    - Strong demand for utility projects including the progress on substations of $21.0 million and power line repair of $3.0 million.

- Gross profit decreased $10.4 million.
  - Largely due to:
    - The absence of higher margin utility projects in 2020 negatively impacted gross profit by $15.0 million, which includes storm power line repair and fire hardening work.
    - Decreased transportation gross profit, largely the completion of a higher margin project of $5.1 million.
    - Institutional projects, primarily the recognition of reduced margins of $9.4 million from lower margin work in 2021 and the impacts of a job loss of $8.4 million related to change order disputes which resulted in a significant job recognizing higher labor and material costs.
  - Partially offset by:
    - Increased industrial gross profit primarily due to a change order settlement of $10.0 million on a significant project.
    - The absence of a job loss in 2020 of $8.9 million related to a large commercial project.
    - An increase in the amount of service work awarded and the progress on that work.

- Selling, general and administrative expense decreased $8.5 million.
  - Largely due to:
    - Lower bad debt expense of $7.0 million, largely due to changes in estimates related to expected credit losses.
    - Lower amortization expense of $3.2 million.
  - Offset in part by:
    - Higher office expenses of $1.3 million.
    - Increased payroll-related costs.

- Other income increased $600,000, largely related to increased earnings on investments.

- Interest expense decreased $600,000, largely related to decreased debt balances due to lower working capital needs and increased cash collections.

- Income tax expense decreased $400,000 as a result of lower income before income taxes.

Outlook Funding for public projects is highly dependent on federal and state funding, such as appropriations to the Federal Highway Administration. The American Rescue Plan provides $1.9 trillion in COVID-19 relief funding for states, schools and local government including broadband infrastructure. States are beginning to move forward with allocating these funds based on federal criteria and state needs, and in some cases, funding of infrastructure projects could positively impact the segment. Additionally, the Infrastructure Investment and Jobs Act, was enacted in the fourth quarter of 2021 and is providing long-term opportunities by designating funds for investments for upgrades to electric and grid infrastructure, transportation systems, airports and electric vehicle infrastructure, all industries this segment supports. In addition, the IRA provides $369 billion in new funding for clean energy programs. These programs include new tax incentives for solar, battery storage and hydrogen development along with funding to expand the production of electric vehicles and the build out of infrastructure to support electric vehicles. The Company will continue to monitor the implementation of these legislative items.

The Company continues to have bidding opportunities in the specialty contracting markets in which it operated in during 2022, as evidenced by the segment's backlog. Although bidding remains highly competitive in all areas, the Company expects the segment's relationship with existing customers, skilled workforce, quality of service and effective cost management will continue to provide a benefit in securing and executing profitable projects in the future. The Company has also seen rapidly growing needs for services across the electric vehicle charging, wind generation and energy storage markets that complement existing renewable projects performed by the Company.

The construction services segment's backlog at December 31 was as follows:

	2022	2021
	(In millions)	
Electrical & mechanical	**$ 1,861**	$ 1,109
Transmission & distribution	**270**	276
	$ 2,131	$ 1,385

The increase in backlog at December 31, 2022, as compared to backlog at December 31, 2021, was largely attributable to the new project opportunities that the Company continues to be awarded across its diverse operations, particularly within the commercial, industrial, institutional, and power utility markets. The increases in backlog have been offset by decreases in the renewable and transportation markets due to the timing of project completions. Period over period increases or decreases in backlog cannot be used as an indicator of future revenues or net income. Of the $2.1 billion of backlog at December 31, 2022, the Company expects to complete an estimated $1.8 billion during 2023. While the Company believes the current backlog of work remains firm, prolonged delays in the receipt of critical supplies and materials could result in customers seeking to delay or terminate existing or pending agreements. As of December 31, 2022, customers have not provided the Company with any indications that they no longer wish to proceed with the planned projects that have been included in backlog. Additionally, the Company continues to further evaluate potential acquisition opportunities that would be accretive to earnings of the Company and continue to grow the segment's backlog. Factors noted in Item 1A - Risk Factors can cause revenues to be realized in periods and at levels that are different from originally projected.

Other

Years ended December 31,	2022	2021	2020	2022 vs. 2021 Variance	2021 vs. 2020 Variance
		(In millions)			
Operating revenues	**$ 17.6**	$ 13.7	$ 11.9	28 %	15 %
Operating expenses:					
Operation and maintenance	**25.1**	15.2	12.2	65 %	25 %
Depreciation, depletion and amortization	**4.4**	4.6	2.7	(4)%	70 %
Taxes, other than income	**.1**	.1	.1	— %	— %
Total operating expenses	**29.6**	19.9	15.0	49 %	33 %
Operating loss	**(12.0)**	(6.2)	(3.1)	94 %	(100)%
Other income	**1.0**	.4	.4	150 %	— %
Interest expense	**1.5**	.3	.8	400 %	(63)%
Loss before income taxes	**(12.5)**	(6.1)	(3.5)	105 %	(74)%
Income tax benefit	**(1.2)**	(.2)	(.4)	500 %	50 %
Net loss	**$ (11.3)**	$ (5.9)	$ (3.1)	(93)%	(90)%

Included in Other is insurance activity at the Company's captive insurer and general and administrative costs and interest expense previously allocated to the exploration and production and refining businesses that do not meet the criteria for income (loss) from discontinued operations.

During 2022, Other experienced higher operation and maintenance expense related to costs incurred of $14.4 million for the announced strategic initiatives, partially offset by a reduction in the estimated losses recorded at the captive insurer. Other was positively impacted by higher premiums included in operating revenues in 2022 for the captive insurer compared to 2021.

Other was negatively impacted in 2021 as a result of higher insurance claims experience at the captive insurer and depreciation expense as compared to 2020. Premiums for the captive insurer were also higher in 2021 compared to 2020, which impacts both operating revenues and operation and maintenance expense.

Intersegment Transactions

Amounts presented in the preceding tables will not agree with the Consolidated Statements of Income due to the Company's elimination of intersegment transactions. The amounts related to these items were as follows:

Years ended December 31,	2022	2021	2020
		(In millions)	
Intersegment transactions:			
Operating revenues	**$ 84.1**	$ 77.6	$ 77.0
Operation and maintenance	**25.9**	18.7	19.1
Purchased natural gas sold	**58.2**	58.9	57.9

For more information on intersegment eliminations, see Item 8 - Note 17.

Liquidity and Capital Commitments

At December 31, 2022, the Company had cash and cash equivalents of $80.5 million and available borrowing capacity of $427.3 million under the outstanding credit facilities of the Company's subsidiaries. The Company expects to meet its obligations for debt maturing within 12 months and its other operating and capital requirements from various sources, including internally generated funds; credit facilities and commercial paper of the Company's subsidiaries, as described later in Capital resources; and the issuance of debt and equity securities if necessary.

Cash flows

Years ended December 31,	**2022**	2021	2020
		(In millions)	
Net cash provided by (used in)			
Operating activities	**$ 510.0**	$ 495.8	$ 768.4
Investing activities	**(638.9)**	(885.9)	(630.2)
Financing activities	**155.2**	384.7	(145.1)
Increase (decrease) in cash and cash equivalents	**26.3**	(5.4)	(6.9)
Cash and cash equivalents -- beginning of year	**54.2**	59.6	66.5
Cash and cash equivalents -- end of year	**$ 80.5**	$ 54.2	$ 59.6

Operating activities

Years ended December 31,	**2022**	2021	2020	2022 vs. 2021 Variance	2021 vs. 2020 Variance
			(In millions)		
Income from continuing operations	**$ 367.3**	$ 377.7	$ 390.5	$ (10.4)	$ (12.8)
Adjustments to reconcile net income to net cash provided by operating activities	**355.0**	350.9	276.2	4.1	74.7
Changes in current assets and current liabilities, net of acquisitions:					
Receivables	**(363.3)**	(60.0)	(2.8)	(303.3)	(57.2)
Inventories	**(46.6)**	(42.3)	(7.2)	(4.3)	(35.1)
Other current assets	**(9.4)**	(72.0)	31.6	62.6	(103.6)
Accounts payable	**186.3**	15.3	16.0	171.0	(.7)
Other current liabilities	**27.0**	(17.6)	35.6	44.6	(53.2)
Pension and postretirement benefit plan contributions	**(.5)**	(.5)	(.4)	—	(.1)
Other noncurrent changes	**(6.0)**	(55.4)	30.3	49.4	(85.7)
Net cash provided by (used in) discontinued operations	**.2**	(.3)	(1.4)	.5	1.1
Net cash provided by operating activities	**$ 510.0**	$ 495.8	$ 768.4	$ 14.2	$ (272.6)

The changes in cash flows from operating activities generally follow the results of operations as discussed in Business Segment Financial and Operating Data and are also affected by changes in working capital. The increase in cash flows provided by operating activities from 2022 to 2021 was largely driven by higher 2022 accounts payable for natural gas purchases due to higher natural gas prices and colder weather, partially offset by the associated increased receivables from customers. Partially offsetting the increase in cash flows provided by operating activities was higher working capital needs at the construction services business due to fluctuations in job activity resulting in higher receivables in the period, as well as lower collections of accounts receivable compared to 2021, offset in part by increased accounts payable. In addition, higher revenues resulted in higher receivables in the period at the construction materials and contracting business.

The decrease in cash flows provided by operating activities from 2021 to 2020 was largely driven by an increase in natural gas purchases and the related unbilled revenues at the natural gas distribution business, partially offset by the associated deferred taxes and increased payables. Also contributing to the decrease was the payment of previously deferred CARES Act taxes and the timing of income tax payments across all of the Company's businesses, as well as the timing of insurance claim payments in relation to receipt of insurance reimbursement at the construction services business. In addition, higher asphalt oil inventory balances due to higher material costs and tank storage balances and higher aggregate inventory balances as a result of production at the businesses acquired at the construction materials and contracting business contributed to the decrease. Partially offsetting the decrease in cash flows provided by operating activities was higher bonus depreciation related to acquisitions at construction materials and contracting business.

Investing activities

Years ended December 31,	**2022**	2021	2020	2022 vs. 2021 Variance	2021 vs. 2020 Variance
			(In millions)		
Capital expenditures	$ **(656.6)**	$ (659.4)	$ (558.0)	$ 2.8	$ (101.4)
Acquisitions, net of cash acquired	**1.8**	(237.7)	(106.0)	239.5	(131.7)
Net proceeds from sale or disposition of property and other	**22.4**	15.2	35.6	7.2	(20.4)
Investments	**(6.5)**	(4.0)	(1.8)	(2.5)	(2.2)
Net cash used in investing activities	$ **(638.9)**	$ (885.9)	$ (630.2)	$ 247.0	$ (255.7)

The decrease in cash used in investing activities from 2022 to 2021 was primarily the result of lower cash used for acquisition activity at the construction materials and contracting business, along with increased proceeds from asset sales. Decreased capital expenditures at the pipeline business as a result of the North Bakken Expansion project being placed in service in February 2022 were mostly offset by increased capital expenditures at the natural gas distribution business for higher natural gas distribution projects, including natural gas mains and meters, and at the electric business for increased electric production projects, including the construction of Heskett Unit 4 and the repower of Diamond Willow.

The increase in cash used in investing activities from 2021 to 2020 was primarily the result of higher cash used in acquisition activity at the construction materials and contracting business, partially offset by decreased acquisition activity at the construction services business. In addition, increased capital expenditures in 2021 at the pipeline business, largely related to the North Bakken Expansion project, and the construction materials and contracting business contributed to the increase, partially offset by lower capital expenditures at the electric and natural gas distribution businesses related to reduced electric transmission and distribution projects and reduced natural gas meters and mains.

Financing activities

Years ended December 31,	**2022**	2021	2020	2022 vs. 2021 Variance	2021 vs. 2020 Variance
			(In millions)		
Issuance of short-term borrowings	$ **246.5**	$ 50.0	$ 75.0	$ 196.5	$ (25.0)
Repayment of short-term borrowings	**—**	(100.0)	(25.0)	100.0	(75.0)
Issuance of long-term debt	**361.6**	554.0	117.4	(192.4)	436.6
Repayment of long-term debt	**(261.7)**	(25.0)	(148.6)	(236.7)	123.6
Debt issuance costs	**(1.9)**	(.9)	(.5)	(1.0)	(.4)
Proceeds from issuance of common stock	**(.1)**	88.8	3.4	(88.9)	85.4
Dividends paid	**(176.9)**	(171.3)	(166.4)	(5.6)	(4.9)
Repurchase of common stock	**(7.4)**	(6.7)	—	(.7)	(6.7)
Tax withholding on stock-based compensation	**(4.9)**	(4.2)	(.4)	(.7)	(3.8)
Net cash provided by (used in) financing activities	$ **155.2**	$ 384.7	$ (145.1)	$ (229.5)	$ 529.8

The decrease in cash flows provided by financing activities from 2022 to 2021 was largely the result of increased repayment and decreased issuance of long-term debt at the construction materials and contracting business. Partially offsetting this was increased issuances of short-term borrowings as long-term debt was replaced with short-term debt at the construction materials and contracting business related to the anticipated spinoff previously discussed and decreased repayment of short-term borrowings at Montana-Dakota. Partially offsetting the decrease was the increased issuance of long-term debt at the construction services business as a result of higher working capital needs and the absence of the issuance of common stock under the Company's "at-the-market" offering during 2022, as discussed in Note 12.

The increase in cash flows provided by financing activities from 2021 to 2020 was largely the result of increased long-term borrowings for acquisitions at the construction materials and contracting business, and increased long-term borrowings, net of repayments, associated with capital expenditures at the pipeline, electric and natural gas distribution businesses. The construction services business also increased its long-term borrowings as a result of increased working capital needs. In addition, net proceeds from the issuance of common stock under the Company's "at-the-market" offering during 2021 also contributed to the increase in cash flows from financing activities. Partially offsetting these increases were decreased short-term borrowings during 2021 at the natural gas distribution business. Montana-Dakota repaid $50 million of short-term borrowings during the first quarter of 2021 related to short-term borrowings during 2020. Montana-Dakota also issued $50 million of short-term borrowings during the first quarter of 2021 related to financing the higher natural gas purchases, as previously discussed, which was repaid prior to the end of the year.

Defined benefit pension plans

The Company has noncontributory qualified defined benefit pension plans for certain employees. Plan assets consist of investments in equity and fixed-income securities. Various actuarial assumptions are used in calculating the benefit expense (income) and liability (asset) related to the pension plans. Actuarial assumptions include assumptions about the discount rate and expected return on plan assets. For 2022, the Company assumed a long-term rate of return on its qualified defined pension plan assets of 6 percent. Due to the decline in the equity and fixed-income markets, the Company experienced more of a loss than estimated on its qualified defined pension plan assets. Differences between actuarial assumptions and actual plan results are deferred and amortized into expense when the accumulated differences exceed 10 percent of the greater of the projected benefit obligation or the market-related value of plan assets. Therefore, this change in asset values will be reflected in future expenses of the plans beginning in 2023. The funded status of the plans did not change significantly with the decrease in assets because the liabilities decreased as well. The Company's benefit obligations for the pension plans also saw a decline in value due to higher discount rates at the end of 2022.

At December 31, 2022, the pension plans' accumulated benefit obligations exceeded these plans' assets by approximately $41.6 million. Pretax pension income reflected in the Consolidated Statements of Income for the years ended December 31, 2022, 2021 and 2020, was $2.3 million, $1.7 million and $684,000, respectively. The Company's pension income is currently projected to be approximately $236,000 in 2023. Funding for the pension plans is actuarially determined. The Company has no minimum funding requirements for its defined benefit pension plans for 2023 due to an additional contribution of $20.0 million in 2019, which created prefunding credits to be used in future periods. There were no minimum required contributions for the years ended December 31, 2022 and 2021 or 2020. For more information on the Company's pension plans, see Item 8 - Note 18.

Capital expenditures

The Company's capital expenditures for 2020 through 2022 and as anticipated for 2023 through 2025 are summarized in the following table.

	Actual (a)			Estimated		
	2020	2021	**2022**	2023	2024	2025
	(In millions)					
Capital expenditures:						
Electric	$ 115	$ 82	**$ 134**	$ 112	$ 127	$ 130
Natural gas distribution	193	170	**240**	224	311	260
Pipeline	62	235	**62**	145	117	127
Construction materials and contracting (b)	191	418	**182**	125	183	173
Construction services (b)	84	29	**36**	38	34	34
Other	3	2	**3**	3	4	4
Total capital expenditures	$ 648	$ 936	**$ 657**	$ 647	$ 776	$ 728

(a) Capital expenditures for 2022, 2021 and 2020 include noncash transactions such as capital expenditure-related accounts payable, the issuance of the Company's equity securities in connection with an acquisition, AFUDC and accrual of holdback payments in connection with acquisitions totaling $1.7 million, $38.7 million and $(15.7) million, respectively.

(b) Capital expenditures for both the construction materials and contracting and construction services segments are subject to change with the announced strategic initiatives.

The 2022 capital expenditures were funded by internal sources, equity issuance, long-term debt issuances and borrowings under credit facilities and issuance of commercial paper of the Company's subsidiaries. The Company has included in the estimated capital expenditures for 2023 through 2025 the development and construction of a renewable natural gas facility at the Deschutes County Landfill near Bend, Oregon, at the natural gas distribution segment; construction of Heskett Unit 4 at the electric segment; and the Wahpeton Expansion and additional growth projects at the pipeline segment, as previously discussed in Business Segment Financial and Operating Data.

Estimated capital expenditures for the years 2023 through 2025 include those for:

- System upgrades
- Routine replacements
- Service extensions
- Routine equipment maintenance and replacements
- Buildings, land and building improvements
- Pipeline and natural gas storage projects
- Power generation and transmission opportunities
- Environmental upgrades, including:
  - The investigation of a manufactured gas plant site
  - The closure of coal ash management units
  - Upgrades to maintain air emissions compliance at electric generating stations
- Other growth opportunities

The Company continues to evaluate potential future acquisitions and other growth opportunities that would be incremental to the outlined capital program; however, they are dependent upon the availability of economic opportunities and, as a result, capital expenditures may vary significantly from the estimates in the preceding table. The Company continuously monitors its capital expenditures for project delays and changes in economic viability and adjusts as necessary. It is anticipated that all of the funds required for capital expenditures for the years 2023 through 2025 will be funded by various sources, including internally generated funds; credit facilities and commercial paper of the Company's subsidiaries, as described later; and issuance of debt and equity securities if necessary.

Capital resources

The Company requires significant cash to support and grow its businesses. The primary sources of cash other than cash generated from operating activities are cash from revolving credit facilities, the issuance of long-term debt and the sale of equity securities.

Debt resources

Certain debt instruments of the Company's subsidiaries contain restrictive and financial covenants and cross-default provisions. In order to borrow under the respective debt instruments, the subsidiary companies must be in compliance with the applicable covenants and certain other conditions, all of which the subsidiaries, as applicable, were in compliance with at December 31, 2022. In the event the subsidiaries do not comply with the applicable covenants and other conditions, alternative sources of funding may need to be pursued. As of December 31, 2022, the Company had investment grade credit ratings at all entities issuing debt. For more information on the covenants, certain other conditions and cross-default provisions, see Item 8 - Note 9.

The following table summarizes the outstanding revolving credit facilities of the Company's subsidiaries at December 31, 2022:

Company	Facility	Facility Limit	Amount Outstanding	Letters of Credit	Expiration Date
			(In millions)		
Montana-Dakota Utilities Co.	Commercial paper/Revolving credit agreement (a)	$ 175.0	$ 117.5	$ —	12/19/24
Cascade Natural Gas Corporation	Revolving credit agreement	$ 100.0 (b)	$ 44.4	$ 2.2 (c)	11/30/27
Intermountain Gas Company	Revolving credit agreement	$ 100.0 (d)	$ 85.6	$ —	10/13/27
Centennial Energy Holdings, Inc.	Commercial paper/Revolving credit agreement (e)	$ 600.0	$ 298.0	$ —	12/19/24

(a) The commercial paper program is supported by a revolving credit agreement with various banks (provisions allow for increased borrowings, at the option of Montana-Dakota on stated conditions, up to a maximum of $225.0 million). At December 31, 2022, there were no amounts outstanding under the revolving credit agreement.
(b) Certain provisions allow for increased borrowings, up to a maximum of $125.0 million.
(c) Outstanding letter(s) of credit reduce the amount available under the credit agreement.
(d) Certain provisions allow for increased borrowings, up to a maximum of $125.0 million.
(e) The commercial paper program is supported by a revolving credit agreement with various banks (provisions allow for increased borrowings, at the option of Centennial on stated conditions, up to a maximum of $700.0 million). At December 31, 2022, there were no amounts outstanding under the revolving credit agreement.

The respective commercial paper programs are supported by revolving credit agreements. While the amount of commercial paper outstanding does not reduce available capacity under the respective revolving credit agreements, Montana-Dakota and Centennial do not issue commercial paper in an aggregate amount exceeding the available capacity under their credit agreements. The commercial paper borrowings may vary during the period, largely the result of fluctuations in working capital requirements due to the seasonality of certain operations of the Company's subsidiaries.

Total equity as a percent of total capitalization was 54 percent and 55 percent at December 31, 2022 and 2021, respectively. This ratio is calculated as the Company's total equity, divided by the Company's total capital. Total capital is the Company's total debt, including short-term borrowings and long-term debt due within 12 months, plus total equity. Management believes this ratio is an indicator of how the Company is financing its operations, as well as its financial strength.

Montana-Dakota Montana-Dakota's objective is to maintain acceptable credit ratings in order to access the capital markets through the issuance of commercial paper. Historically, downgrades in credit ratings have not limited, nor are currently expected to limit, Montana-Dakota's ability to access the capital markets. If Montana-Dakota were to experience a downgrade of its credit ratings in the future, it may need to borrow under its credit agreement and may experience an increase in overall interest rates with respect to its cost of borrowings. Prior to the maturity of the credit agreement, Montana-Dakota expects that it will negotiate the extension or replacement of this agreement. If Montana-Dakota is unable to successfully negotiate an extension of, or replacement for, the credit agreement, or if the fees on this facility become too expensive, which Montana-Dakota does not currently anticipate, it would seek alternative funding.

MDU Energy Capital On October 21, 2022, MDU Energy Capital entered into a $11.5 million term loan agreement with a SOFR-based variable interest rate and a maturity date of July 21, 2023. The agreement contains customary covenants and provisions, including a covenant of MDU Energy Capital not to permit, at any time, the ratio of total debt to total capitalization to be greater than 70 percent. The covenants also include certain restrictions on the sale of certain assets, loans and investments.

Cascade On November 30, 2022, Cascade amended and restated its revolving credit agreement to extend the maturity date to November 30, 2027. Any borrowings under the revolving credit agreement are classified as long-term debt as they are intended to be refinanced on a long-term basis through continued borrowings. The credit agreement contains customary covenants and provisions, including a covenant of Cascade not to permit, at any time, the ratio of total debt to total capitalization to be greater than 65 percent. Other covenants include restrictions on the sale of certain assets, limitations on indebtedness and the making of certain investments.

On June 15, 2022, Cascade issued $50.0 million of senior notes under a note purchase agreement with maturity dates ranging from June 15, 2032 to June 15, 2052, at a weighted average interest rate of 4.50 percent. The agreement contains customary covenants and provisions, including a covenant of Cascade not to permit, at any time, the ratio of debt to total capitalization to be greater than 65 percent. Other covenants include restrictions on the sale of certain assets, limitations on indebtedness and the making of certain investments.

On January 20, 2023, Cascade entered into a $150.0 million term loan agreement with a SOFR-based variable interest rate and a maturity date of January 19, 2024. The agreement contains customary covenants and provisions, including a covenant of Cascade not to permit, at any time, the ratio of total debt to total capitalization to be greater than 65 percent. The covenants also include certain restrictions on the sale of certain assets, loans and investments.

Intermountain On October 13, 2022, Intermountain amended and restated its revolving credit agreement to increase the borrowing capacity to $100.0 million and extend the maturity date to October 13, 2027. Any borrowings under the revolving credit agreement are classified as long-term debt as they are intended to be refinanced on a long-term basis through continued borrowings. The credit agreement contains customary covenants and provisions, including a covenant of Intermountain not to permit, at any time, the ratio of total debt to total capitalization to be greater than 65 percent. Other covenants include restrictions on the sale of certain assets, limitations on indebtedness and the making of certain investments.

On June 15, 2022, Intermountain issued $40.0 million of senior notes under a note purchase agreement with maturity dates ranging from June 15, 2052 to June 15, 2062, at a weighted average interest rate of 4.68 percent. The agreement contains customary covenants and provisions, including a covenant of Intermountain not to permit, at any time, the ratio of debt to total capitalization to be greater than 65 percent. Other covenants include restrictions on the sale of certain assets, limitations on indebtedness and the making of certain investments.

On January 20, 2023, Intermountain entered into a $125.0 million term loan agreement with a SOFR-based variable interest rate and a maturity date of January 19, 2024. The agreement contains customary covenants and provisions, including a covenant of Intermountain not to permit, at any time, the ratio of total debt to total capitalization to be greater than 65 percent. The covenants also include certain restrictions on the sale of certain assets, loans and investments.

Centennial Centennial's objective is to maintain acceptable credit ratings in order to access the capital markets through the issuance of commercial paper. Historically, downgrades in Centennial's credit ratings have not limited, nor are currently expected to limit, Centennial's ability to access the capital markets. If Centennial were to experience a downgrade of its credit ratings in the future, it may need to borrow under its credit agreement and may experience an increase in overall interest rates with respect to its cost of borrowings. Prior to the maturity of the Centennial credit agreement, Centennial expects that it will negotiate the extension or replacement of this agreement, which provides credit support to access the capital markets. In the event Centennial is unable to successfully negotiate this agreement, or in the event the fees on this facility become too expensive, which Centennial does not currently anticipate, it would seek alternative funding.

On March 18, 2022, Centennial entered into a $100.0 million term loan agreement with a SOFR-based variable interest rate and a maturity date of March 17, 2023. The agreement contains customary covenants and provisions, including a covenant of Centennial not to permit, at any time, the ratio of total debt to total capitalization to be greater than 65 percent. The covenants also include certain restrictions on the sale of certain assets, loans and investments.

On March 23, 2022, Centennial issued $150.0 million of senior notes under a note purchase agreement with maturity dates ranging from March 23, 2032 to March 23, 2034, at a weighted average interest rate of 3.71 percent. The agreement contains customary covenants and provisions, including a covenant of Centennial not to permit, at any time, the ratio of debt to total capitalization to be greater than 60 percent. Other covenants include restrictions on the sale of certain assets, limitations on indebtedness and the making of certain investments.

On December 19, 2022, Centennial entered into a $135.0 million term loan agreement with a SOFR-based variable interest rate and a maturity date of December 18, 2023. The agreement contains customary covenants and provisions, including a covenant of Centennial not to permit, at any time, the ratio of total debt to total capitalization to be greater than 65 percent. The covenants also include certain restrictions on the sale of certain assets, loans and investments.

WBI Energy Transmission On December 22, 2022, WBI Energy Transmission amended its uncommitted note purchase and private shelf agreement to increase capacity to $350.0 million with an expiration date of December 22, 2025. On December 22, 2022, WBI Energy Transmission issued $40.0 million in senior notes under the private shelf agreement with a maturity date of December 22, 2030, at an interest rate of 6.67 percent. WBI Energy Transmission had $235.0 million of notes outstanding at December 31, 2022, which reduced the remaining capacity under this uncommitted private shelf agreement to $115.0 million. This agreement contains customary covenants and provisions, including a covenant of WBI Energy Transmission not to permit, as of the end of any fiscal quarter, the ratio of total debt to total capitalization to be greater than 55 percent. Other covenants include a limitation on priority debt, restrictions on the sale of certain assets and the making of certain investments.

Equity Resources

The Company currently has a shelf registration statement on file with the SEC, under which the Company may issue and sell any combination of common stock and debt securities. The Company may sell such securities if warranted by market conditions and the Company's capital requirements. Any public offer and sale of such securities will be made only by means of a prospectus meeting the requirements of the Securities Act and the rules and regulations thereunder. For more information on the Company's equity, see Item 8 - Note 12.

In August 2020, the Company amended the Distribution Agreement dated February 22, 2019, with J.P. Morgan Securities LLC and MUFG Securities Americas Inc., as sales agents. This agreement, as amended, allows the offering, issuance and sale of up to 6.4 million shares of the Company's common stock in connection with an “at-the-market” offering. The common stock may be offered for sale, from time to time, in accordance with the terms and conditions of the agreement. As of December 31, 2022, the Company had capacity to issue up to 3.6 million additional shares of common stock under the "at-the-market" offering program. The Company did not issue any shares under the "at-the-market" offering program in 2022. Proceeds from the sale of shares of common stock under the agreement have been and are expected to be used for general corporate purposes, which may include, among other things, working capital, capital expenditures, debt repayment and the financing of acquisitions.

Dividend restrictions

For information on the Company's dividends and dividend restrictions, see Item 8 - Note 12.

Material cash requirements

For more information on the Company's contractual obligations on long-term debt, operating leases and purchase commitments, see Item 8 - Notes 9, 10 and 21. At December 31, 2022, the Company's material cash requirements under these obligations were as follows:

	Less than 1 year	1-3 years	3-5 years	More than 5 years	Total
			(In millions)		
Short-term debt	$ 246.5	$ —	$ —	$ —	$ 246.5
Long-term debt maturities*	78.1	654.7	371.6	1,743.9	2,848.3
Estimated interest payments**	163.0	229.0	182.2	903.7	1,477.9
Operating leases	38.9	46.5	18.5	40.0	143.9
Purchase commitments	712.9	416.2	185.3	676.5	1,990.9
	$ 1,239.4	$ 1,346.4	$ 757.6	$ 3,364.1	$ 6,707.5

* Unamortized debt issuance costs and discount are excluded from the table.

** Represents the estimated interest payments associated with the Company's long-term debt outstanding at December 31, 2022, assuming current interest rates and consistent amounts outstanding until their respective maturity dates over the periods indicated in the table above.

Material short-term cash requirements of the Company include repayment of outstanding borrowings and interest payments on those agreements, payments on operating lease agreements, payment of obligations on purchase commitments and asset retirement obligations. At December 31, 2022, the current portion of asset retirement obligations was $4.6 million and was included in other accrued liabilities on the Consolidated Balance Sheets.

Material long-term cash requirements of the Company include repayment of outstanding borrowings and interest payments on those agreements, payments on operating lease agreements, payment of obligations on purchase commitments and asset retirement obligations. At December 31, 2022, the Company had total liabilities of $410.5 million related to asset retirement obligations that are excluded from the table above. Due to the nature of these obligations, the Company cannot determine precisely when the payments will be made to settle these obligations. For more information, see Item 8 - Note 11.

Not reflected in the previous table are $2.0 million in uncertain tax positions at December 31, 2022.

The Company has no minimum funding requirements for its defined benefit pension plans for 2023 due to an additional contribution of $20.0 million in 2019.

The Company's MEPP contributions are based on union employee payroll, which cannot be determined in advance for future periods. The Company may also be required to make additional contributions to its MEPPs as a result of their funded status. For more information, see Item 1A - Risk Factors and Item 8 - Note 18.

New Accounting Standards

For information regarding new accounting standards, see Item 8 - Note 2, which is incorporated herein by reference.

Critical Accounting Estimates

The Company has prepared its financial statements in conformity with GAAP. The preparation of its financial statements 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, as well as the reported amounts of revenues and expenses during the reporting period. Management reviews these estimates and assumptions based on historical experience, changes in business conditions and other relevant factors believed to be reasonable under the circumstances.

Critical accounting estimates are defined as estimates that require management to make assumptions about matters that are uncertain at the time the estimate was made and changes in the estimates could have a material impact on the Company's financial position or results of operations. The Company's critical accounting estimates are subject to judgments and uncertainties that affect the application of its significant accounting policies discussed in Item 8 - Note 2. As additional information becomes available, or actual amounts are determinable, the recorded estimates are revised. Consequently, the Company's financial position or results of operations may be materially different when reported under different conditions or when using different assumptions in the application of the following critical accounting estimates.

Goodwill

The Company performs its goodwill impairment testing annually in the fourth quarter. In addition, the test is performed on an interim basis whenever events or circumstances indicate that the carrying amount of goodwill may not be recoverable. Examples of such events or circumstances may include a significant adverse change in business climate, weakness in an industry in which the Company's reporting units operate or recent significant cash or operating losses with expectations that those losses will continue.

The Company has determined that the reporting units for its goodwill impairment test are its operating segments, or components of an operating segment, that constitute a business for which discrete financial information is available and for which segment management regularly reviews the operating results. For more information on the Company's operating segments, see Item 8 - Note 17. Goodwill impairment, if any, is measured by comparing the fair value of each reporting unit to its carrying value. If the fair value of a reporting unit exceeds its carrying value, the goodwill of the reporting unit is not impaired. If the carrying value of a reporting unit exceeds its fair value, the Company must record an impairment loss for the amount that the carrying value of the reporting unit, including goodwill, exceeds the fair value of the reporting unit. For the years ended December 31, 2022, 2021 and 2020, there were no impairment losses recorded.

At October 31, 2022, the fair value substantially exceeded the carrying value at the Company's reporting units with goodwill, with the exception of the natural gas distribution reporting unit. The Company's annual impairment testing indicated the natural gas distribution reporting unit's fair value is not substantially in excess of its carrying value ("cushion"). Based on the Company's assessment, the estimated fair value of the natural gas distribution reporting unit exceeded its carrying value, which includes $345.7 million of goodwill, by approximately 8 percent as of October 31, 2022. The decrease in the natural gas distribution reporting unit's cushion from the prior year was primarily attributable to the risk adjusted cost of capital increasing from 5.0 percent in 2021 to 6.4 percent 2022, which directly correlates with the treasury rates at the date of the test. The natural gas distribution reporting unit is at risk of future impairment if projected operating results are not met or other inputs into the fair value measurement model change.

Determining the fair value of a reporting unit requires judgment and the use of significant estimates which include assumptions about the Company's future revenue, profitability and cash flows, long-term growth rates, amount and timing of estimated capital expenditures, inflation rates, risk adjusted cost of capital, operational plans, and current and future economic conditions, among others. The fair value of each reporting unit is determined using a weighted combination of income and market approaches. The Company believes that the estimates and assumptions used in its impairment assessments are reasonable and based on available market information.

The Company uses a discounted cash flow methodology for its income approach. Under the income approach, the discounted cash flow model determines fair value based on the present value of projected cash flows over a specified period and a residual value related to future cash flows beyond the projection period. Both values are discounted using a rate which reflects the best estimate of the risk adjusted cost of capital at each reporting unit. The risk adjusted cost of capital varies by reporting unit and was in the range of 6 percent to 10 percent in 2022, 5 percent to 9 percent for 2021 and 4 percent to 8 percent for 2020.

Under the market approach, the Company estimates fair value using various multiples derived from enterprise value to EBITDA for comparative peer companies for each respective reporting unit. These multiples are applied to operating data for each reporting unit to arrive at an indication of fair value. In addition, the Company adds a reasonable control premium when calculating the fair value utilizing the peer multiples, which is estimated as the premium that would be received in a sale in an orderly transaction between market participants. The Company used a 20 percent control premium in 2022 and a 15 percent control premium in 2021 and 2020.

The Company uses significant judgment in estimating its five-year forecast. The assumptions underlying cash flow projections are in sync as applicable with the Company's strategy and assumptions. Future projections are heavily correlated with the current year results of operations. Future results of operations may vary due to economic and financial impacts. The long-term growth rates are developed by management based on industry data, management's knowledge of the industry and management's strategic plans. The long-term growth rate varies by reporting unit. Construction materials and contracting and construction services long-term growth rate was 3 percent in 2022, 2021 and 2020. Natural gas distribution's long-term growth rate has been in the range of 1.5 percent to 3 percent in 2022, 2021 and 2020.

Regulatory accounting

The Company is subject to rate regulation by state public service commissions and/or the FERC. Regulatory assets generally represent incurred or accrued costs that have been deferred and are expected to be recovered in rates charged to customers. Regulatory liabilities generally represent amounts that are expected to be refunded to customers in future rates or amounts collected in current rates for future costs.

Management continually assesses the likelihood of recovery in future rates of incurred costs and refunds to customers associated with regulatory assets and liabilities. Decisions made by the various regulatory agencies can directly impact the amount and timing of these items. Therefore, expected recovery or refund of these deferred items generally is based on specific ratemaking decisions or precedent for each item. If future recovery of costs is no longer probable, the Company would be required to include those costs in the statement of income or accumulated other comprehensive loss in the period in which it is no longer deemed probable. The Company believes that the accounting subject to rate regulation remains appropriate and its regulatory assets are probable of recovery in current rates or in future rate proceedings. At December 31, 2022 and 2021, the Company's regulatory assets were $494.8 million and $476.5 million, respectively, and regulatory liabilities were $474.9 million and $445.1 million, respectively. At December 31, 2022 and 2021, regulatory assets in recovery were $427.8 million and $367.7 million, respectively, and regulatory assets not in recovery were $67.0 million and $108.8 million, respectively.

Revenue recognition

Revenue is recognized to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. The recognition of revenue requires the Company to make estimates and assumptions that affect the reported amounts of revenue. The accuracy of revenues reported on the Consolidated Financial Statements depends on, among other things, management's estimates of total costs to complete projects because the Company uses the cost-to-cost measure of progress on construction contracts for revenue recognition.

To determine the proper revenue recognition method for contracts, the Company evaluates whether two or more contracts should be combined and accounted for as one single contract and whether the combined or single contract should be accounted for as more than one performance obligation. This evaluation requires significant judgment and the decision to combine a group of contracts or separate the combined or single contract into multiple performance obligations could change the amount of revenue and profit recorded in a given period. For most contracts, the customer contracts with the Company to provide a significant service of integrating a complex set of tasks and components into a single project. Hence, the Company's contracts are generally accounted for as one performance obligation.

The Company recognizes construction contract revenue over time using an input method based on the cost-to-cost measure of progress for contracts because it best depicts the transfer of assets to the customer which occurs as the Company incurs costs on the contract. Under the cost-to-cost measure of progress, the costs incurred are compared with total estimated costs of a performance obligation. Revenues are recorded proportionately to the costs incurred. This method depends largely on the ability to make reasonably dependable estimates related to the extent of progress toward completion of the contract, contract revenues and contract costs. Since contract prices are generally set before the work is performed, the estimates pertaining to every project could contain significant unknown risks such as volatile labor, material and fuel costs, weather delays, adverse project site conditions, unforeseen actions by regulatory agencies, performance by subcontractors, job management and relations with project owners. Changes in estimates could have a material effect on the Company's results of operations, financial position and cash flows. For the years ended December 31, 2022 and 2021, the Company's total construction contract revenue was $3.8 billion and $3.0 billion, respectively.

Several factors are evaluated in determining the bid price for contract work. These include, but are not limited to, the complexities of the job, past history performing similar types of work, seasonal weather patterns, competition and market conditions, job site conditions, work force safety, reputation of the project owner, availability of labor, materials and fuel, project location and project completion dates. As a project commences, estimates are continually monitored and revised as information becomes available and actual costs and conditions surrounding the job become known. If a loss is anticipated on a contract, the loss is immediately recognized.

Contracts are often modified to account for changes in contract specifications and requirements. The Company considers contract modifications to exist when the modification either creates new or changes the existing enforceable rights and obligations. Generally, contract modifications are for goods or services that are not distinct from the existing contract due to the significant integration of services provided in the context of the contract and are accounted for as if they were part of that existing contract. The effect of a contract modification on the transaction price and the measure of progress for the performance obligation to which it relates, is recognized as an adjustment to revenue on a cumulative catch-up basis.

The Company's construction contracts generally contain variable consideration including liquidated damages, performance bonuses or incentives, claims, unpriced change orders and penalties or index pricing. The variable amounts usually arise upon achievement of certain performance metrics or change in project scope. The Company estimates the amount of revenue to be recognized on variable consideration using one of the two prescribed estimation methods, the expected value method or the most likely amount method, depending on which method best predicts the most likely amount of consideration the Company expects to be entitled to or expects to incur. Assumptions as to the occurrence of future events and the likelihood and amount of variable consideration are made during the contract performance period. Estimates of variable consideration and assessment of anticipated performance and all information (historical, current and forecasted) that is reasonably available to management. The Company only includes variable consideration in the estimated transaction price to the extent it is probable that a significant reversal of cumulative revenue recognized will not occur or when the uncertainty associated with the variable consideration is resolved. Changes in circumstances could impact management's estimates made in determining the value of variable consideration recorded. When determining if the variable consideration is constrained, the Company considers if factors exist that could increase the likelihood of the magnitude of a potential reversal of revenue. The Company updates its estimate of the transaction price each reporting period and the effect of variable consideration on the transaction price is recognized as an adjustment to revenue on a cumulative catch-up basis.

The Company believes its estimates surrounding the cost-to-cost method are reasonable based on the information that is known when the estimates are made. The Company has contract administration, accounting and management control systems in place that allow its estimates to be updated and monitored on a regular basis. Because of the many factors that are evaluated in determining bid prices, it is inherent that the Company's estimates have changed in the past and will continually change in the future as new information becomes available for each job.

Pension and other postretirement benefits

The Company has noncontributory defined benefit pension plans and other postretirement benefit plans for certain eligible employees. Various actuarial assumptions are used in calculating the benefit expense (income) and liability (asset) related to these plans. Costs of providing pension and other postretirement benefits bear the risk of change, as they are dependent upon numerous factors based on assumptions of future conditions.

The Company makes various assumptions when determining plan costs, including the current discount rates and the expected long-term return on plan assets, the rate of compensation increases, actuarially determined mortality data and health care cost trend rates. In selecting the expected long-term return on plan assets, which is considered to be one of the key variables in determining benefit expense or income, the Company considers historical returns, current market conditions, the mix of investments and expected future market trends, including changes in interest rates and equity and bond market performance. Another key variable in determining benefit expense or income is the discount rate. In selecting the discount rate, the Company matches forecasted future cash flows of the pension and postretirement plans to a yield curve which consists of a hypothetical portfolio of high-quality corporate bonds with varying maturity dates, as well as other factors, as a basis. The Company's pension and other postretirement benefit plan assets are primarily made up of equity and fixed-income investments. Fluctuations in actual equity and bond market returns, as well as changes in general interest rates, may result in increased or decreased pension and other postretirement benefit costs in the future. Management estimates the rate of compensation increase based on long-term assumed wage increases and the health care cost trend rates are determined by historical and future trends.

The Company believes the estimates made for its pension and other postretirement benefits are reasonable based on the information that is known when the estimates are made. These estimates and assumptions are subject to a number of variables and are expected to change in the future. Estimates and assumptions will be affected by changes in the discount rate, the expected long-term return on plan assets, the rate of compensation increase and health care cost trend rates. A 50 basis point change in the assumed discount rate and the expected long-term return on plan assets would have had the following effects at December 31, 2022:

	Pension Benefits		Other Postretirement Benefits	
	50 Basis Point Increase	50 Basis Point Decrease	50 Basis Point Increase	50 Basis Point Decrease
	(In millions)			
Discount rate				
Projected benefit obligation as of December 31, 2022	$ (13.7)	$ 14.8	$ (2.5)	$ 2.7
Net periodic benefit cost (credit) for 2023	$ —	$ (.1)	$ (.2)	$ .2
Expected long-term return on plan assets				
Net periodic benefit cost (credit) for 2023	$ (1.6)	$ 1.6	$ (.4)	$ .4

A 100 basis point change in the assumed health care cost trend rates would have had the following effects at December 31, 2022:

	100 Basis Point Increase	100 Basis Point Decrease
	(In millions)	
Service and interest cost components for 2023	$ .1	$ (.1)
Postretirement benefit obligation as of December 31, 2022	$ 1.8	$ (1.6)

The Company plans to continue to use its current methodologies to determine plan costs. For more information on the assumptions used in determining plan costs, see Item 8 - Note 18.

Business combinations

The Company accounts for acquisitions on the Consolidated Financial Statements starting from the date of the acquisition, which is the date that control is obtained. The acquisition method of accounting requires acquired assets and liabilities assumed be recorded at their respective fair values as of the date of the acquisition. The excess of the purchase price over the fair value of the assets acquired and liabilities assumed is recorded as goodwill. The estimation of fair values of acquired assets and liabilities assumed by the Company requires significant judgment and requires various assumptions. Although independent appraisals may be used to assist in the determination of the fair value of certain assets and liabilities, the appraised values may be based on significant estimates provided by management. The amounts and useful lives assigned to depreciable and amortizable assets compared to amounts assigned to goodwill, which is not amortized, can affect the results of operations in the period of and periods subsequent to a business combination.

In determining fair values of acquired assets and liabilities assumed, the Company uses various observable inputs for similar assets or liabilities in active markets and various unobservable inputs, which includes the use of valuation models. Fair values are based on various factors including, but not limited to, age and condition of property, maintenance records, auction values for equipment with similar characteristics, recent sales and listings of comparable properties, data collected from drill holes and other subsurface investigations and geologic data. The Company primarily uses the market and cost approaches in determining the fair value of land and property, plant and equipment. A combination of the market and income approaches are used for aggregate reserves and intangibles, primarily a discounted cash flow model. The Company must develop reasonable and supportable assumptions to evaluate future cash flows. The process is highly subjective and requires a large degree of management judgement. Assumptions used may vary for each specific business combination due to unique circumstances of each transaction. Assumptions may include discount rate, time period, terminal value and growth rate. The values generated from the discounted cash flow model are sensitive to the assumptions used. Inaccurate assumptions can lead to deviations from the values generated.

There is a measurement period after the acquisition date during which the Company may adjust the amounts recognized for a business combination. Any such adjustments are recorded in the period the adjustment is determined with the corresponding offset to goodwill. These adjustments are typically based on obtaining additional information that existed at the acquisition date regarding the assets acquired and the liabilities assumed. The measurement period ends once the Company has obtained all necessary information that existed as of the acquisition date, but does not extend beyond one year from the date of the acquisition. Once the measurement period has ended, any adjustments to assets acquired or liabilities assumed are recorded in income from continuing operations.

Income taxes

The Company is required to make judgments regarding the potential tax effects of various financial transactions and ongoing operations to estimate the Company's obligation to taxing authorities. These tax obligations include income, real estate, franchise and sales/use taxes. Judgments related to income taxes require the recognition in the Company's financial statements that a tax position is more-likely-than-not to be sustained on audit.

Judgment and estimation is required in developing the provision for income taxes and the reporting of tax-related assets and liabilities and, if necessary, any valuation allowances. The interpretation of tax laws can involve uncertainty, since tax authorities may interpret such laws differently. Actual income tax could vary from estimated amounts and may result in favorable or unfavorable impacts to net income, cash flows and tax-related assets and liabilities. In addition, the effective tax rate may be affected by other changes including the allocation of property, payroll and revenues between states.

The Company assesses the deferred tax assets for recoverability taking into consideration historical and anticipated earnings levels; the reversal of other existing temporary differences; available net operating losses and tax carryforwards; and available tax planning strategies that could be implemented to realize the deferred tax assets. Based on this assessment, management must evaluate the need for, and amount of, a valuation allowance against the deferred tax assets. As facts and circumstances change, adjustment to the valuation allowance may be required.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

The Company is exposed to the impact of market fluctuations associated with commodity prices and interest rates. The Company has policies and procedures to assist in controlling these market risks and from time to time has utilized derivatives to manage a portion of its risk.

Interest rate risk

The Company uses fixed and variable rate long-term debt to partially finance capital expenditures, including acquisitions, and mandatory debt retirements. These debt agreements expose the Company to market risk related to changes in interest rates. The Company manages this risk by attempting to take advantage of favorable market conditions when timing the placement of long-term financing. The Company from time to time has utilized interest rate swap agreements to manage a portion of the Company's interest rate risk and may take advantage of such agreements in the future to minimize such risk. For additional information on the Company's long-term debt, see Item 8 - Notes 8 and 9. At December 31, 2022 and 2021, the Company had no outstanding interest rate hedges.

The following table shows the amount of long-term debt, which excludes unamortized debt issuance costs and discount, and related weighted average interest rates, both by expected maturity dates, as of December 31, 2022.

	2023	2024	2025	2026	2027	Thereafter	Total	Fair Value
				(Dollars in millions)				
Long-term debt:								
Fixed rate	$ 78.1	$ 61.4	$ 177.8	$ 140.8	$ 100.8	$ 1,743.9	$ 2,302.8	$ 1,930.7
Weighted average interest rate	3.7 %	4.2 %	4.0 %	5.7 %	5.5 %	4.3 %	4.4 %	
Variable rate	$ —	$ 415.5	$ —	$ —	$ 130.0	$ —	$ 545.5	$ 545.5
Weighted average interest rate	— %	5.1 %	— %	— %	6.3 %	— %	5.4 %	

Commodity price risk

The Company enters into commodity price derivative contracts to minimize the price volatility associated with natural gas costs for its customers at its natural gas distribution segment. At December 31, 2022 and 2021, these contracts were not material. For more information on the Company's derivatives, see Item 8 - Note 2.

Item 8. Financial Statements and Supplementary Data

Management's Report on Internal Control Over Financial Reporting

The management of MDU Resources Group, Inc. is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934. The Company's internal control system is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the Company's financial statements for external purposes in accordance with generally accepted accounting principles in the United States of America.

All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. 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.

Management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2022. In making this assessment, 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 our evaluation under the framework in *Internal Control-Integrated Framework (2013)*, management concluded that the Company's internal control over financial reporting was effective as of December 31, 2022.

The effectiveness of the Company's internal control over financial reporting as of December 31, 2022, has been audited by Deloitte & Touche LLP, an independent registered public accounting firm, as stated in their report.

David L. Goodin	Jason L. Vollmer
President and Chief Executive Officer	Vice President and Chief Financial Officer

Report of Independent Registered Public Accounting Firm

To the Stockholders and the Board of Directors of MDU Resources Group, Inc.

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of MDU Resources Group, Inc. and subsidiaries (the "Company") as of December 31, 2022 and 2021, the related consolidated statements of income, comprehensive income, equity, and cash flows for each of the three years in the period ended December 31, 2022, and the related notes and the schedules 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 the results of its operations and its cash flows for each of the three years in the period ended December 31, 2022 and December 31, 2021, 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 24, 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 matters communicated below are matters arising from the current-period audit of the financial statements that were communicated or required to be communicated to the audit committee and that (1) relate 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 matters below, providing separate opinions on the critical audit matters or on the accounts or disclosures to which they relate.

Revenue from Contracts with Customers-Construction Contract Revenue-Refer to Notes 2 and 3 to the financial statements

Critical Audit Matter Description

The Company recognizes construction contract revenue over time using an input method based on the cost-to-cost measure of progress for contracts because it best depicts the transfer of assets to the customer, which occurs as the Company incurs costs on the contract. Under the cost-to-cost measure of progress, the costs incurred are compared with total estimated costs of a performance obligation. Revenues are recorded proportionately to the costs incurred. This method depends largely on the ability to make reasonably dependable estimates related to the extent of progress toward completion of the contract, contract revenues, contract costs, and contract profits. The accounting for these contracts involves judgment, particularly as it relates to the process of estimating total costs and profit for the performance obligation. For the year ended December 31, 2022, the Company recognized $3.8 billion of construction contract revenue.

Given the judgments necessary to estimate total costs and profit for the performance obligations used to recognize revenue for construction contracts, auditing such estimates required extensive audit effort due to the volume and complexity of construction contracts and a high degree of auditor judgment when performing audit procedures and evaluating the results of those procedures.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to management’s estimates of total costs and profit for the performance obligations used to recognize revenue for construction contracts included the following, among others:

- We tested the design and operating effectiveness of management's controls over construction contract revenue, including those over management’s estimation of total costs and profit for the performance obligations.

- We developed an expectation of the amount of construction contract revenues for certain performance obligations based on prior year markups, and taking into account current year events, applied to the construction contract costs in the current year and compared our expectation to the amount of construction contract revenues recorded by management.
- We selected a sample of construction contracts and performed the following:
  - Evaluated whether the contracts were properly included in management's calculation of construction contract revenue based on the terms and conditions of each contract, including whether continuous transfer of control to the customer occurred as progress was made toward fulfilling the performance obligation.
  - Observed the work sites and inspecting the progress to completion for certain construction contracts.
  - Compared the transaction prices, including estimated variable consideration, to the consideration expected to be received based on current rights and obligations under the contracts and any modifications that were agreed upon with the customers.
  - Evaluated management's identification of distinct performance obligations by evaluating whether the underlying goods and services were highly interdependent and interrelated.
  - Tested the accuracy and completeness of the costs incurred to date for the performance obligation.
  - Evaluated the estimates of total cost and profit for the performance obligation by:
    - Comparing total costs incurred to date to the costs management estimated to be incurred to date and selecting specific cost types to compare costs incurred to date to management's estimated costs at completion.
    - Evaluating management's ability to achieve the estimates of total cost and profit by performing corroborating inquiries with the Company's project managers and engineers, and comparing the estimates to management's work plans, engineering specifications, and supplier contracts.
    - Comparing management's estimates for the selected contracts to costs and profits of similar performance obligations, when applicable.
  - Tested the mathematical accuracy of management's calculation of construction contract revenue for the performance obligation.
- We evaluated management's ability to estimate total costs and profits accurately by comparing actual costs and profits to management's historical estimates for performance obligations that have been fulfilled.

Regulatory Matters-Impact of Rate Regulation on the Financial Statements-Refer to Notes 2 and 20 to the financial statements

Critical Audit Matter Description

Through the Company's regulated utility businesses, it provides electric and natural gas services to customers, and generates, transmits, and distributes electricity. The Company is subject to rate regulation by federal and state utility regulatory agencies (collectively, the "Commissions"), which have jurisdiction with respect to the rates of electric and natural gas distribution companies in states where the Company operates. The Company's regulated utility businesses account for certain income and expense items under the provisions of regulatory accounting, which requires these businesses to defer as regulatory assets or liabilities certain items that would have otherwise been reflected as expense or income, respectively, based on the expected regulatory treatment in future rates. The expected recovery, refund or future rate reduction of these deferred items generally is based on specific ratemaking decisions or precedent for each item. Accounting for the economics of rate regulation impacts multiple financial statement line items and disclosures, such as property, plant, and equipment; regulatory assets and liabilities; operating revenues; operation and maintenance expense; depreciation expense; and income taxes.

Rates are determined and approved in regulatory proceedings based on an analysis of the Company's costs to provide utility service and a return on the Company's investment in the regulated utility businesses. 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 regulation of rates is premised on the full recovery of prudently incurred costs and a reasonable rate of return on invested capital. Decisions to be made by the Commissions in the future will impact the accounting for regulated operations.

We identified the impact of rate regulation 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 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 or future rate reduction to customers. Given management's accounting judgments are based on assumptions about the outcome of future decisions by the Commissions, auditing these judgments requires specialized knowledge of accounting for rate regulation 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 included the following, among others:

- We tested the design and operating 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 tested management's controls over the initial recognition of amounts as 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 and other public utilities in the Company's significant jurisdictions, procedural memorandums, filings made by the Company or 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 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, and for any evidence that might contradict management's assertions.
- We obtained an analysis from management regarding probability of recovery for regulatory assets or refund or future reduction in rates for regulatory liabilities not yet addressed in a regulatory order to assess management's assertion that amounts are probable of recovery, or a future reduction in rates.
- We inspected minutes of the board of directors to identify any evidence that may contradict management's assertions regarding probability of recovery or refunds. We also inquired of management regarding current year rate filings and new regulatory assets or liabilities.

Goodwill – Natural Gas Distribution Reporting Unit – Refer to Notes 2 and 7 to the financial statements

Critical Audit Matter Description

The Company's evaluation of goodwill for impairment involves the comparison of the fair value of the reporting unit to its carrying value. The Company determines the fair value of its reporting units using the discounted cash flow model and the market approach. The determination of the fair value requires management to make significant estimates and assumptions related to forecasts of future cash flows, earnings before interest, taxes, depreciation, and amortization (EBITDA), long-term growth rates, and discount rates. Changes in these assumptions could have a significant impact on either the fair value or the amount of any goodwill impairment charge. The goodwill balance was $764 million as of December 31, 2022, of which $346 million was allocated to the Natural Gas Distribution Reporting Unit ("Natural Gas Distribution"). The fair value of Natural Gas Distribution exceeded its carrying value as of the measurement date and, therefore, no impairment was recognized.

We identified goodwill for Natural Gas Distribution as a critical audit matter because of the significant judgments made by management to estimate the fair value and the difference between its fair value and carrying value. This required a high degree of auditor judgment and an increased extent of effort, including the need to involve our fair value specialists, when performing audit procedures to evaluate the reasonableness of management's estimates and assumptions related to forecasts of future cash flows, EBITDA and selection of the discount rate and long-term growth rate.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to the forecasts of future cash flows, EBITDA, the discount rate, and the long-term growth rate, used by management to estimate the fair value of Natural Gas Distribution included the following, among others:

- We tested the effectiveness of controls over management's goodwill impairment evaluation, including those over the determination of the fair value of Natural Gas Distribution, such as controls related to management's forecasts of future cash flows, EBITDA and selection of the discount rate and long-term growth rate.
- We evaluated management's ability to accurately forecast by comparing actual results to management's historical forecasts.
- We evaluated the reasonableness of management's forecasts by comparing the forecasts to (1) historical results, (2) internal communications to management and the Board of Directors, and (3) forecasted information included in the Company press releases as well as in analyst and industry reports of the Company and companies in its peer group.
- We evaluated the impact of changes in management's forecasts from the October 31, 2022, annual measurement date to December 31, 2022.
- With the assistance of our fair value specialists, we evaluated the reasonableness of the valuation methodology, discount rate, and long-term growth rate, including testing the underlying source information and the mathematical accuracy of the calculations, and developing a range of independent estimates and comparing those to the discount rate and long-term growth rate selected by management.
- With the assistance of our fair value specialists, we evaluated the EBITDA multiples, including testing the underlying source information and mathematical accuracy of the calculations, and comparing the multiples selected by management to its guideline companies.

Deloitte & Touche LLP

Minneapolis, Minnesota
February 24, 2023

We have served as the Company's auditor since 2002.

Report of Independent Registered Public Accounting Firm

To the Stockholders and the Board of Directors of MDU Resources Group, Inc.

Opinion on Internal Control over Financial Reporting

We have audited the internal control over financial reporting of MDU Resources Group, 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 24, 2023, expressed an unqualified opinion on those consolidated 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.

Deloitte & Touche LLP

Minneapolis, Minnesota
February 24, 2023

Consolidated Statements of Income

Years ended December 31,		2022		2021		2020
		(In thousands, except per share amounts)				
Operating revenues:						
Electric, natural gas distribution and regulated pipeline	$	**1,735,759**	$	1,390,343	$	1,249,146
Non-regulated pipeline, construction materials and contracting, construction services and other		**5,238,105**		4,290,390		4,283,604
Total operating revenues		**6,973,864**		5,680,733		5,532,750
Operating expenses:						
Operation and maintenance:						
Electric, natural gas distribution and regulated pipeline		**374,708**		366,586		353,184
Non-regulated pipeline, construction materials and contracting, construction services and other		**4,604,149**		3,712,037		3,675,078
Total operation and maintenance		**4,978,857**		4,078,623		4,028,262
Purchased natural gas sold		**757,883**		483,118		390,269
Depreciation, depletion and amortization		**327,826**		299,214		285,100
Taxes, other than income		**243,338**		211,454		217,253
Electric fuel and purchased power		**92,007**		74,105		66,941
Total operating expenses		**6,399,911**		5,146,514		4,987,825
Operating income		**573,953**		534,219		544,925
Other income		**7,379**		26,416		26,711
Interest expense		**119,273**		93,984		96,519
Income before income taxes		**462,059**		466,651		475,117
Income taxes		**94,783**		88,920		84,590
Income from continuing operations		**367,276**		377,731		390,527
Discontinued operations, net of tax		**213**		400		(322)
Net income	$	**367,489**	$	378,131	$	390,205
Earnings per share - basic:						
Income from continuing operations	$	**1.81**	$	1.87	$	1.95
Discontinued operations, net of tax		**—**		—		—
Earnings per share - basic	$	**1.81**	$	1.87	$	1.95
Earnings per share - diluted:						
Income from continuing operations	$	**1.81**	$	1.87	$	1.95
Discontinued operations, net of tax		**—**		—		—
Earnings per share - diluted	$	**1.81**	$	1.87	$	1.95
Weighted average common shares outstanding - basic		**203,358**		202,076		200,502
Weighted average common shares outstanding - diluted		**203,462**		202,383		200,571

The accompanying notes are an integral part of these consolidated financial statements.

Consolidated Statements of Comprehensive Income

Years ended December 31,	2022	2021	2020
		(In thousands)	
Net income	**$ 367,489**	$ 378,131	$ 390,205
Other comprehensive income (loss):			
Reclassification adjustment for loss on derivative instruments included in net income, net of tax of $177, $145 and $145 in 2022, 2021 and 2020, respectively	**413**	446	446
Postretirement liability adjustment:			
Postretirement liability gains (losses) arising during the period, net of tax of $3,965, $1,626 and $(2,606) in 2022, 2021 and 2020, respectively	**12,007**	4,876	(8,395)
Amortization of postretirement liability losses included in net periodic benefit credit, net of tax of $597, $615 and $630 in 2022, 2021 and 2020, respectively	**1,819**	1,870	1,922
Reclassification of postretirement liability adjustment from regulatory asset, net of tax of $(1,086), $— and $— in 2022, 2021 and 2020, respectively	**(3,265)**	—	—
Postretirement liability adjustment	**10,561**	6,746	(6,473)
Net unrealized (loss) gain on available-for-sale investments:			
Net unrealized loss on available-for-sale investments arising during the period, net of tax of $(177), $(67) and $— in 2022, 2021 and 2020, respectively	**(667)**	(252)	(1)
Reclassification adjustment for loss on available-for-sale investments included in net income, net of tax of $31, $36 and $14 in 2022, 2021 and 2020, respectively	**114**	134	52
Net unrealized (loss) gain on available-for-sale investments	**(553)**	(118)	51
Other comprehensive income (loss)	**10,421**	7,074	(5,976)
Comprehensive income attributable to common stockholders	**$ 377,910**	$ 385,205	$ 384,229

The accompanying notes are an integral part of these consolidated financial statements.

Consolidated Balance Sheets

December 31,	2022	2021
Assets	(In thousands, except shares and per share amounts)	
Current assets:		
Cash and cash equivalents	$ 80,517	$ 54,161
Receivables, net	1,305,642	946,741
Inventories	387,525	335,609
Current regulatory assets	165,092	118,691
Prepayments and other current assets	72,972	95,741
Total current assets	2,011,748	1,550,943
Noncurrent assets:		
Property, plant and equipment	9,364,038	8,972,849
Less accumulated depreciation, depletion and amortization	3,272,493	3,216,461
Net property, plant and equipment	6,091,545	5,756,388
Goodwill	763,500	765,386
Other intangible assets, net	17,532	22,578
Regulatory assets	329,659	357,851
Investments	161,913	175,476
Operating lease right-of-use assets	119,375	124,138
Other	165,509	157,675
Total noncurrent assets	7,649,033	7,359,492
Total assets	$ 9,660,781	$ 8,910,435
Liabilities and Stockholders' Equity		
Current liabilities:		
Short-term borrowings	$ 246,500	$ —
Long-term debt due within one year	78,031	148,053
Accounts payable	657,168	478,933
Taxes payable	70,810	80,372
Dividends payable	45,245	44,229
Accrued compensation	88,662	81,904
Operating lease liabilities due within one year	34,516	35,368
Regulatory liabilities due within one year	26,440	16,303
Other accrued liabilities	232,231	207,078
Total current liabilities	1,479,603	1,092,240
Noncurrent liabilities:		
Long-term debt	2,763,394	2,593,847
Deferred income taxes	631,303	591,962
Asset retirement obligations	405,885	458,061
Regulatory liabilities	448,454	428,790
Operating lease liabilities	85,534	89,253
Other	259,479	273,408
Total noncurrent liabilities	4,594,049	4,435,321
Commitments and contingencies		
Stockholders' equity:		
Common stock Authorized - 500,000,000 shares, $1.00 par value Shares issued - 204,162,814 at December 31, 2022 and 203,889,661 at December 31, 2021	204,163	203,889
Other paid-in capital	1,466,037	1,461,205
Retained earnings	1,951,138	1,762,410
Accumulated other comprehensive loss	(30,583)	(41,004)
Treasury stock at cost - 538,921 shares	(3,626)	(3,626)
Total stockholders' equity	3,587,129	3,382,874
Total liabilities and stockholders' equity	$ 9,660,781	$ 8,910,435

The accompanying notes are an integral part of these consolidated financial statements.

Consolidated Statements of Equity

Years ended December 31, 2022, 2021 and 2020

(In thousands, except shares)

	Common Stock				Accumulated Other Comprehensive Loss	Treasury Stock		
	Shares	Amount	Other Paid-in Capital	Retained Earnings		Shares	Amount	Total
At December 31, 2019	200,922,790	$200,923	$1,355,404	$1,336,647	$(42,102)	(538,921)	$(3,626)	$2,847,246
Net income	—	—	—	390,205	—	—	—	390,205
Other comprehensive loss	—	—	—	—	(5,976)	—	—	(5,976)
Dividends declared on common stock	—	—	—	(168,489)	—	—	—	(168,489)
Employee stock-based compensation	—	—	13,096	—	—	—	—	13,096
Issuance of common stock upon vesting of stock-based compensation, net of shares used for tax withholdings	26,406	26	(388)	—	—	—	—	(362)
Issuance of common stock	112,002	112	3,273	—	—	—	—	3,385
At December 31, 2020	201,061,198	201,061	1,371,385	1,558,363	(48,078)	(538,921)	(3,626)	3,079,105
Net Income	—	—	—	378,131	—	—	—	378,131
Other comprehensive income	—	—	—	—	7,074	—	—	7,074
Dividends declared on common stock	—	—	—	(174,084)	—	—	—	(174,084)
Employee stock-based compensation	—	—	14,709	—	—	—	—	14,709
Repurchase of common stock	—	—	—	—	—	(392,294)	(6,701)	(6,701)
Issuance of common stock upon vesting of stock-based compensation, net of shares used for tax withholdings	—	—	(10,828)	—	—	392,294	6,701	(4,127)
Issuance of common stock	2,828,463	2,828	85,939	—	—	—	—	88,767
At December 31, 2021	203,889,661	203,889	1,461,205	1,762,410	(41,004)	(538,921)	(3,626)	3,382,874
Net income	—	—	—	367,489	—	—	—	367,489
Other comprehensive income	—	—	—	—	10,421	—	—	10,421
Dividends declared on common stock	—	—	—	(178,761)	—	—	—	(178,761)
Employee stock-based compensation	—	—	10,254	—	—	—	—	10,254
Repurchase of common stock	—	—	—	—	—	(266,821)	(7,399)	(7,399)
Issuance of common stock upon vesting of stock-based compensation, net of shares used for tax withholdings	—	—	(12,303)	—	—	266,821	7,399	(4,904)
Issuance of common stock	273,153	274	6,881	—	—	—	—	7,155
At December 31, 2022	**204,162,814**	**$204,163**	**$1,466,037**	**$1,951,138**	**$(30,583)**	**(538,921)**	**$(3,626)**	**$3,587,129**

The accompanying notes are an integral part of these consolidated financial statements.

Consolidated Statements of Cash Flows

Years ended December 31,	**2022**	2021	2020
		(In thousands)	
Operating activities:			
Net income	**$ 367,489**	$ 378,131	$ 390,205
Income (loss) from discontinued operations, net of tax	**213**	400	(322)
Income from continuing operations	**367,276**	377,731	390,527
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	**327,826**	299,214	285,100
Deferred income taxes	**23,326**	60,250	(1,801)
Provision for credit losses	**6,133**	1,085	10,576
Amortization of debt issuance costs	**1,461**	1,333	2,162
Employee stock-based compensation costs	**10,254**	14,709	13,096
Pension and postretirement benefit plan net periodic benefit credit	**(6,018)**	(4,900)	(3,001)
Unrealized losses (gains) on investments	**12,732**	(7,728)	(14,563)
Gains on sales of assets	**(20,723)**	(13,056)	(15,350)
Changes in current assets and liabilities, net of acquisitions:			
Receivables	**(363,314)**	(60,024)	(2,780)
Inventories	**(46,588)**	(42,302)	(7,221)
Other current assets	**(9,360)**	(71,964)	31,601
Accounts payable	**186,285**	15,247	15,955
Other current liabilities	**27,011**	(17,650)	35,591
Pension and postretirement benefit plan contributions	**(507)**	(476)	(434)
Other noncurrent changes	**(5,944)**	(55,367)	30,291
Net cash provided by continuing operations	**509,850**	496,102	769,749
Net cash provided by (used in) discontinued operations	**214**	(325)	(1,375)
Net cash provided by operating activities	**510,064**	495,777	768,374
Investing activities:			
Capital expenditures	**(656,588)**	(659,425)	(558,007)
Acquisitions, net of cash acquired	**1,745**	(237,718)	(105,979)
Net proceeds from sale or disposition of property and other	**22,439**	15,238	35,557
Investments	**(6,477)**	(3,973)	(1,814)
Net cash used in investing activities	**(638,881)**	(885,878)	(630,243)
Financing activities:			
Issuance of short-term borrowings	**246,500**	50,000	75,000
Repayment of short-term borrowings	**—**	(100,000)	(25,000)
Issuance of long-term debt	**361,650**	554,027	117,450
Repayment of long-term debt	**(261,674)**	(24,979)	(148,634)
Debt issuance costs	**(1,936)**	(918)	(477)
Proceeds from issuance of common stock	**(149)**	88,767	3,385
Dividends paid	**(176,915)**	(171,354)	(166,405)
Repurchase of common stock	**(7,399)**	(6,701)	—
Tax withholding on stock-based compensation	**(4,904)**	(4,127)	(362)
Net cash provided by (used in) financing activities	**155,173**	384,715	(145,043)
Increase (decrease) in cash and cash equivalents	**26,356**	(5,386)	(6,912)
Cash and cash equivalents - beginning of year	**54,161**	59,547	66,459
Cash and cash equivalents - end of year	**$ 80,517**	$ 54,161	$ 59,547

The accompanying notes are an integral part of these consolidated financial statements.

Notes to Consolidated Financial Statements

Note 1 - Basis of Presentation

The abbreviations and acronyms used throughout are defined following the Notes to Consolidated Financial Statements. The consolidated financial statements of the Company include the accounts of the following businesses: electric, natural gas distribution, pipeline, construction materials and contracting, construction services and other. The electric and natural gas distribution businesses, as well as a portion of the pipeline business, are regulated. Construction materials and contracting, construction services and the other businesses, as well as a portion of the pipeline business, are non-regulated. For further descriptions of the Company's businesses, see Note 17.

On August 4, 2022, the Company announced its board of directors unanimously approved a plan to pursue the separation of Knife River from the Company. The separation is planned as a tax-free spinoff transaction to the Company’s stockholders for U.S. federal income tax purposes. As the next step of the Company’s strategic planning, on November 3, 2022, the Company announced its intention to create two pure-play publicly traded companies, one focused on regulated energy delivery and the other on construction materials, and to achieve this future structure, the board authorized management to commence a strategic review process of MDU Construction Services.

Discontinued operations include the supporting activities of Fidelity and the assets and liabilities of the Company's discontinued operations have been classified as held for sale and are included in prepayments and other current assets, noncurrent assets - other and other accrued liabilities on the Consolidated Balance Sheets and are not material to the financial statements for any period presented. The results and supporting activities are shown in income (loss) from discontinued operations on the Consolidated Statements of Income. Unless otherwise indicated, the amounts presented in the accompanying notes to the consolidated financial statements relate to the Company's continuing operations.

Management has also evaluated the impact of events occurring after December 31, 2022, up to the date of issuance of these consolidated financial statements on February 24, 2023, that would require recognition or disclosure in the financial statements.

Principles of consolidation

The consolidated financial statements were prepared in accordance with GAAP and include the accounts of the Company and its wholly-owned subsidiaries. All intercompany balances and transactions have been eliminated in consolidation, except for certain transactions related to the Company's regulated operations in accordance with GAAP. For more information on intercompany revenues, see Note 17.

The statements also include the Company's ownership interests in the assets, liabilities and expenses of jointly owned electric transmission and generating facilities. See Note 19 for additional information.

Use of estimates

The preparation of financial statements in conformity with GAAP requires the Company 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, as well as the reported amounts of revenues and expenses during the reporting period. Estimates are used for items such as long-lived assets and goodwill; fair values of acquired assets and liabilities under the acquisition method of accounting; aggregate reserves; property depreciable lives; tax provisions; revenue recognized using the cost-to-cost measure of progress for contracts; expected credit losses; environmental and other loss contingencies; regulatory assets expected to be recovered in rates charged to customers; costs on construction contracts; unbilled revenues; actuarially determined benefit costs; asset retirement obligations; lease classification; present value of right-of-use assets and lease liabilities; and the valuation of stock-based compensation. As additional information becomes available, or actual amounts are determinable, the recorded estimates are revised. Consequently, operating results can be affected by revisions to prior accounting estimates.

Note 2 - Significant Accounting Policies

New accounting standards

The following table provides a brief description of the accounting pronouncements applicable to the Company and the potential impact on its financial statements and or disclosures:

Standard	Description	Effective date	Impact on financial statements/ disclosures
Recently adopted accounting standards			
ASU 2021-10 - Government Assistance	In November 2021, the FASB issued guidance on modifying the disclosure requirements to increase the transparency of government assistance including disclosure of the types of assistance, an entity's accounting for the assistance and the effect of the assistance on an entity's financial statements.	January 1, 2022	The Company determined the guidance did not have a material impact on its disclosures for the year ended December 31, 2022.
ASU 2020-04 - Reference Rate Reform	In March 2020, the FASB issued optional guidance to ease the facilitation of the effects of reference rate reform on financial reporting. The guidance applies to certain contract modifications, hedging relationships and other transactions that reference LIBOR or another reference rate expected to be discontinued because of reference rate reform. Beginning January 1, 2022, LIBOR or other discontinued reference rates cannot be applied to new contracts. New contracts will incorporate a new reference rate, which includes SOFR. LIBOR or other discontinued reference rates cannot be applied to contract modifications or hedging relationships entered into or evaluated after December 31, 2022. Existing contracts referencing LIBOR or other reference rates expected to be discontinued must identify a replacement rate by June 30, 2023.	Effective as of March 12, 2020 through December 31, 2022	For more information, see ASU 2022-06 - Reference Rate Reform: Deferral of Sunset Date in recently issued accounting standards not yet adopted.
Recently issued accounting standards not yet adopted			
ASU 2022-06 - Reference Rate Reform: Deferral of Sunset Date	In December 2022, the FASB included a sunset provision within ASC 848 based on expectations of when LIBOR would cease being published. At the time ASU 2020-04 was issued, the UK Financial Conduct Authority had established its intent to cease overnight tenors of LIBOR after December 31, 2021. In March 2021, the UK Financial Conduct Authority announced that the intended cessation date of the overnight tenors of LIBOR would be June 30, 2023 which is beyond the current sunset date of ASC 848. The amendments in this Update defer the sunset date of ASC 848 from December 31, 2022 to December 31, 2024, after which entities will no longer be permitted to apply the relief in ASC 848.	December 31, 2024	The Company has updated its credit agreements to include language regarding the successor or alternate rate to LIBOR, and a review of other contracts and agreements is on-going. The Company does not expect the guidance to have a material impact on its results of operations, financial position, cash flows or disclosures.

Cash and cash equivalents

The Company considers all highly liquid investments purchased with an original maturity of three months or less to be cash equivalents.

Revenue recognition

Revenue is recognized when a performance obligation is satisfied by transferring control over a product or service to a customer. Revenue is measured based on consideration specified in a contract with a customer and excludes any sales incentives and amounts collected on behalf of third parties. The Company is considered an agent for certain taxes collected from customers. As such, the Company presents revenues net of these taxes at the time of sale to be remitted to governmental authorities, including sales and use taxes.

The electric and natural gas distribution segments generate revenue from the sales of electric and natural gas products and services, which includes retail and transportation services. These segments establish a customer's retail or transportation service account based on the customer's application/contract for service, which indicates approval of a contract for service. The contract identifies an obligation to provide service in exchange for delivering or standing ready to deliver the identified commodity; and the customer is obligated to pay for the service as provided in the applicable tariff. The product sales are based on a fixed rate that includes a base and per-unit rate, which are included in approved tariffs as determined by state or federal regulatory agencies. The quantity of the commodity consumed or transported determines the total per-unit revenue. The service provided, along with the product consumed or transported, are a single performance obligation because both are required in combination to successfully transfer the contracted product or service to the customer. Revenues are recognized over time as customers receive and consume the products and services. The method of measuring progress toward the completion of the single performance obligation is on a per-unit output method basis, with revenue recognized based on the direct measurement of the value to the customer of the goods or services transferred to date. For contracts governed by the Company’s utility tariffs, amounts are billed monthly with the amount due between 15 and 22 days of receipt of the invoice depending on the applicable state’s tariff. For other contracts not governed by tariff, payment terms are net 30 days. At this time, the segment has no material obligations for returns, refunds or other similar obligations.

The pipeline segment generates revenue from providing natural gas transportation and underground storage services, as well as other energy-related services to both third parties and internal customers, largely the natural gas distribution segment. The pipeline segment establishes a contract with a customer based upon the customer’s request for firm or interruptible natural gas transportation or storage service(s). The contract identifies an obligation for the segment to provide the requested service(s) in exchange for consideration from the customer over a specified term. Depending on the type of service(s) requested and contracted, the service provided may include transporting or storing an identified quantity of natural gas and/or standing ready to deliver or store an identified quantity of natural gas. Natural gas transportation and storage revenues are based on fixed rates, which may include reservation fees and/or per-unit commodity rates. The services provided by the segment are generally treated as single performance obligations satisfied over time simultaneous to when the service is provided and revenue is recognized. Rates for the segment’s regulated services are based on its FERC approved tariff or customer negotiated rates, and rates for its non-regulated services are negotiated with its customers and set forth in the contract. For contracts governed by the company’s tariff, amounts are billed on or before the ninth business day of the following month and the amount is due within 12 days of receipt of the invoice. For other contracts not governed by the tariff, payment terms are net 30 days. At this time, the segment has no material obligations for returns, refunds or other similar obligations.

The construction materials and contracting segment generates revenue from contracting services and construction materials sales. This segment focuses on the vertical integration of its contracting services with its construction materials to support the aggregate-based product lines. This segment provides contracting services to a customer when a contract has been signed by both the customer and a representative of the segment obligating a service to be provided in exchange for the consideration identified in the contract. The nature of the services this segment provides generally include integrating a set of services and related construction materials into a single project to create a distinct bundle of goods and services, which the Company has determined are single performance obligations. The transaction price includes the fixed consideration required pursuant to the original contract price together with any additional consideration, to which the Company expects to be entitled to, associated with executed change orders plus the estimate of variable consideration to which the Company expects to be entitled, subject to the following constraint. The nature of this segment's contracts gives rise to several types of variable consideration. Examples of variable consideration include: liquidated damages; performance bonuses or incentives and penalties; claims; unpriced change orders; and index pricing. The variable amounts usually arise upon achievement of certain performance metrics or change in project scope. The Company estimates the amount of revenue to be recognized on variable consideration using one of the two prescribed estimation methods, the expected value method or the most likely amount method, depending on which method best predicts the most likely amount of consideration the Company expects to be entitled to or expects to incur. Assumptions as to the occurrence of future events and the likelihood and amount of variable consideration are made during the contract performance period. Estimates of variable consideration and determination of whether to include estimated amounts in the transaction price are based largely on the assessment of anticipated performance and all information (historical, current and forecasted) that is reasonably available to management. The Company only includes variable consideration in the estimated transaction price to the extent it is probable that a significant reversal of cumulative revenue recognized will not occur or when the uncertainty associated with the variable consideration is resolved. Changes in circumstances could impact management's estimates made in determining the value of variable consideration recorded. When determining if the variable consideration is constrained, the Company considers if factors exist that could increase the likelihood or the magnitude of a potential reversal of revenue. The Company updates its estimate of the transaction price each reporting period and the effect of variable consideration on the transaction price is recognized as an adjustment to revenue on a cumulative catch-up basis. Contract revenue is recognized over time using an input method based on the cost-to-cost measure of progress on a project. This is the preferred method of measuring revenue because the costs incurred have been determined to represent the best indication of the overall progress toward the transfer of such goods or services promised to a customer. Under the cost-to-cost measure of progress, the costs incurred are compared with total estimated costs of a performance obligation. Revenues are recorded proportionately to the costs incurred. The percentage of completion is determined on a performance obligation basis. This segment also sells construction materials to third parties and internal customers. The contract for material sales is the use of a sales order or an invoice, which includes the pricing and payment terms. All material contracts contain a single performance obligation for the delivery of a single distinct product or a distinct separately identifiable bundle of products and services. Revenue is recognized at a point in time when the performance obligation has been satisfied with the delivery of the products or services. The warranties associated with the sales are those consistent with a standard warranty that the product meets certain specifications for quality or those required by law. For most contracts, amounts billed to customers are due within 30 days of receipt. There are no material obligations for returns, refunds or other similar obligations.

The construction services segment generates revenue from specialty contracting services which also includes the sale of construction equipment and other supplies. This segment provides specialty contracting services to a customer when a contract has been signed by both the customer and a representative of the segment obligating a service to be provided in exchange for the consideration identified in the contract. The nature of the services this segment provides generally includes multiple promised goods and services in a single project to create a distinct bundle of goods and services, which the Company has determined are single performance obligations. The transaction price includes the fixed consideration required pursuant to the original contract price together with any additional consideration, to which the Company expects to be entitled to, associated with executed change orders plus the estimate of variable consideration to which the Company expects to be entitled, subject to the following constraint. The nature of the segment's contracts gives rise to several types of variable consideration. Examples of variable consideration include: liquidated damages; performance bonuses or incentives and penalties; claims; unpriced change orders; and index pricing. The variable amounts usually arise upon achievement of certain performance metrics or change in project scope. The Company estimates the amount of revenue to be recognized on variable consideration using one of the two prescribed estimation methods, the expected value method or the most likely amount method, depending on which method best predicts the most likely amount of consideration the Company expects to be entitled to or expects to incur. Assumptions as to the occurrence of future events and the likelihood and amount of variable consideration are made during the contract performance period. Estimates of variable consideration and determination of whether to include estimated amounts in the transaction price are based largely on the assessment of anticipated performance and all information (historical, current, and forecasted) that is reasonably available to management. The Company only includes variable consideration in the estimated transaction price to the extent it is probable that a significant reversal of cumulative revenue recognized will not occur or when the uncertainty associated with the variable consideration is resolved. Changes in circumstances could impact management's estimates made in determining the value of variable consideration recorded. When determining if the variable consideration is constrained, the Company considers if factors exist that could increase the likelihood or the magnitude of a potential reversal of revenue. The Company updates its estimate of the transaction price each reporting period and the effect of variable consideration on the transaction price is recognized as an adjustment to revenue on a cumulative catch-up basis. Contract revenue is recognized over time using the input method based on the measurement of progress on a project. This is the preferred method of measuring revenue because the costs incurred have been determined to represent the best indication of the overall progress toward the transfer of such goods or services promised to a customer. Under the cost-to-cost measure of progress, the costs incurred are compared with total estimated costs of a performance obligation. Revenues are recorded proportionately to the costs incurred. This segment also sells construction equipment and other supplies to third parties and internal customers. The contract for these sales is the use of a sales order or invoice, which includes the pricing and payment terms. All such contracts include a single performance obligation for the delivery of a single distinct product or a distinct separately identifiable bundle of products and services. Revenue is recognized at a point in time when the performance obligation has been satisfied with the delivery of the products or services. The warranties associated with the sales are those consistent with a standard warranty that the product meets certain specifications for quality or those required by law. For most contracts, amounts billed to customers are due within 30 days of receipt. There are no material obligations for returns, refunds or other similar obligations.

The Company recognizes all other revenues when services are rendered or goods are delivered.

Legal costs

The Company expenses external legal fees as they are incurred.

Business combinations

For all business combinations, the Company preliminarily allocates the purchase price of the acquisitions to the assets acquired and liabilities assumed based on their estimated fair values as of the acquisition dates and are considered provisional until final fair values are determined or the measurement period has passed. The Company expects to record adjustments as it accumulates the information needed to estimate the fair value of assets acquired and liabilities assumed, including working capital balances, estimated fair value of identifiable intangible assets, property, plant and equipment, total consideration and goodwill. The excess of the purchase price over the aggregate fair values is recorded as goodwill. The Company calculated the fair value of the assets acquired in 2022 and 2021 using a market or cost approach (or a combination of both). Fair values for some of the assets were determined based on Level 3 inputs including estimated future cash flows, discount rates, growth rates, sales projections, retention rates and terminal values, all of which require significant management judgment and are susceptible to change. The discount rate used in calculating the fair value of common stock issued in a business combination is determined by using a Black-Scholes-Merton model. The model uses Level 2 inputs including risk-free interest rate, volatility range and dividend yield. The final fair value of the net assets acquired may result in adjustments to the assets and liabilities, including goodwill, and will be made as soon as practical, but no later than 12 months from the respective acquisition dates. Any subsequent measurement period adjustments are not expected to have a material impact on the Company's results of operations.

Receivables and allowance for expected credit losses

Receivables consist primarily of trade and contracting services receivables from the sale of goods and services net of expected credit losses. The Company's trade receivables are all due in 12 months or less. The total balance of receivables past due 90 days or more was $45.6 million and $44.8 million at December 31, 2022 and 2021, respectively.

The Company's expected credit losses are determined through a review using historical credit loss experience, changes in asset specific characteristics, current conditions and reasonable and supportable future forecasts, among other specific account data, and is performed at least quarterly. The Company develops and documents its methodology to determine its allowance for expected credit losses at each of its reportable business segments. Risk characteristics used by the business segments may include customer mix, knowledge of customers and general economic conditions of the various local economies, among others. Specific account balances are written off when management determines the amounts to be uncollectible. Management has reviewed the balance reserved through the allowance for expected credit losses and believes it is reasonable.

Details of the Company's expected credit losses were as follows:

	Electric	Natural gas distribution	Pipeline	Construction materials and contracting	Construction services	Total
			(In thousands)			
At December 31, 2020	$ 899	$ 2,571	$ 2	$ 6,164	$ 5,722	$ 15,358
Current expected credit loss provision*	1,099	2,188	—	68	(2,250)	1,105
Less write-offs charged against the allowance	2,139	4,072	—	826	1,032	8,069
Credit loss recoveries collected	410	819	—	—	93	1,322
At December 31, 2021	269	1,506	2	5,406	2,533	9,716
Current expected credit loss provision	1,325	4,084	—	538	186	6,133
Less write-offs charged against the allowance	1,625	4,913	—	467	625	7,630
Credit loss recoveries collected	406	938	—	—	68	1,412
At December 31, 2022	**$ 375**	**$ 1,615**	**$ 2**	**$ 5,477**	**$ 2,162**	**$ 9,631**

* Includes impacts from businesses acquired.

Receivables also consist of accrued unbilled revenue representing revenues recognized in excess of amounts billed. Accrued unbilled revenue at MDU Energy Capital was $181.8 million and $144.9 million at December 31, 2022 and 2021, respectively.

Amounts representing balances billed but not paid by customers under retainage provisions in contracts at December 31 were as follows:

	2022	2021
	(In thousands)	
Short-term retainage*	**$ 120,333**	$ 70,600
Long-term retainage**	**19,511**	10,742
Total retainage	**$ 139,844**	$ 81,342

* Expected to be paid within 12 months or less and included in receivables, net.
** Included in noncurrent assets - other.

Inventories and natural gas in storage

Natural gas in storage for the Company's regulated operations is generally valued at lower of cost or market using the last-in, first-out method or lower of cost or net realizable value using the average cost or first-in, first-out method. The majority of all other inventories are valued at the lower of cost or net realizable value using the average cost method. Inventories include production costs incurred as part of the Company's aggregate mining activities. These inventoriable production costs include all mining and processing costs associated with the production of aggregates. Stripping costs incurred during the production phase, which represent costs of removing overburden and waste materials to access mineral deposits, are a component of inventoriable production costs. The portion of the cost of natural gas in storage expected to be used within 12 months was included in inventories. Inventories at December 31 consisted of:

	2022	2021
	(In thousands)	
Aggregates held for resale	**$ 199,110**	$ 184,363
Asphalt oil	**68,609**	57,002
Materials and supplies	**40,056**	30,629
Merchandise for resale	**40,296**	28,501
Natural gas in storage (current)	**22,533**	18,867
Other	**16,921**	16,247
Total	**$ 387,525**	$ 335,609

The remainder of natural gas in storage, which largely represents the cost of gas required to maintain pressure levels for normal operating purposes, was included in noncurrent assets - other and was $47.5 million at both December 31, 2022 and 2021.

Property, plant and equipment

Additions to property, plant and equipment are recorded at cost. Aggregate mining development costs are capitalized and classified as land improvements and depreciated over the lower of the estimated life of the reserves or the life of the associated improvement. The Company begins capitalizing development costs at a point when reserves are determined to be proven or probable and economically mineable. Capitalization of these costs cease when production commences. The cost of acquiring reserves in connection with a business combination are valued at fair value. When regulated assets are retired, or otherwise disposed of in the ordinary course of business, the original cost of the asset is charged to accumulated depreciation. With respect to the retirement or disposal of all other assets, the resulting gains or losses are recognized as a component of income.

The Company is permitted to capitalize AFUDC on regulated construction projects and to include such amounts in rate base when the related facilities are placed in service. In addition, the Company capitalizes interest, when applicable, on certain contracting services projects associated with its other operations. The amount of AFUDC for the years ended December 31 was as follows:

	2022	2021	2020
		(In thousands)	
AFUDC - borrowed	**$ 2,236**	$ 2,833	$ 2,640
AFUDC - equity	**$ 2,165**	$ 6,961	$ 1,270

Generally, property, plant and equipment are depreciated on a straight-line basis over the average useful lives of the assets, except for depletable aggregate reserves, which are depleted based on the units-of-production method. The Company uses proven and probable aggregate reserves as the denominator in its units-of production calculation. Exploration costs are expensed as incurred in operation and maintenance expense and production costs are either expensed or capitalized to inventory.

The Company collects removal costs for certain plant assets in regulated utility rates. These amounts are recorded as regulatory liabilities on the Consolidated Balance Sheets.

Impairment of long-lived assets, excluding goodwill

The Company reviews the carrying values of its long-lived assets, including mining and related assets, whenever events or changes in circumstances indicate that such carrying values may not be recoverable. The Company tests long-lived assets for impairment at a level significantly lower than that of goodwill impairment testing. Long-lived assets or groups of assets that are evaluated for impairment at the lowest level of largely independent identifiable cash flows at an individual operation or group of operations collectively serving a local market. The determination of whether an impairment has occurred is based on an estimate of undiscounted future cash flows attributable to the assets, compared to the carrying value of the assets. If impairment has occurred, the amount of the impairment recognized is determined by estimating the fair value of the assets and recording a loss if the carrying value is greater than the fair value. The impairments are recorded in operation and maintenance expense on the Consolidated Statements of Income.

No impairment losses were recorded in 2022, 2021 or 2020. Unforeseen events and changes in circumstances could require the recognition of impairment losses at some future date.

Regulatory assets and liabilities

The Company's regulated businesses are subject to various state and federal agency regulations. The accounting policies followed by these businesses are generally subject to the Uniform System of Accounts of the FERC as well as the provisions of ASC 980 - *Regulated Operations*. These accounting policies differ in some respects from those used by the Company's non-regulated businesses.

The Company's regulated businesses account for certain income and expense items under the provisions of regulatory accounting, which requires these businesses to defer as regulatory assets or liabilities certain items that would have otherwise been reflected as expense or income, respectively. The Company records regulatory assets or liabilities at the time the Company determines the amounts to be recoverable in current or future rates. Regulatory assets and liabilities are being amortized consistently with the regulatory treatment established by the FERC and the applicable state public service commission. See Note 6 for more information regarding the nature and amounts of these regulatory deferrals.

Natural gas costs recoverable or refundable through rate adjustments

Under the terms of certain orders of the applicable state public service commissions, the Company is deferring natural gas commodity, transportation and storage costs that are greater or less than amounts presently being recovered through its existing rate schedules. Such orders generally provide that these amounts are recoverable or refundable through rate adjustments. Natural gas costs refundable through rate adjustments were $1.0 million and $6.7 million at December 31, 2022 and 2021, respectively, which were included in regulatory liabilities due within one year on the Consolidated Balance Sheets. Natural gas costs recoverable through rate adjustments were $141.3 million and $91.6 million at December 31, 2022 and 2021, respectively, which were included in current regulatory assets and noncurrent assets - regulatory assets on the Consolidated Balance Sheets.

Goodwill

Goodwill represents the excess of the purchase price over the fair value of identifiable net tangible and intangible assets acquired in a business combination. Goodwill is required to be tested for impairment annually, which the Company completes in the fourth quarter, or more frequently if events or changes in circumstances indicate that goodwill may be impaired.

The Company has determined that the reporting units for its goodwill impairment test are its operating segments, or components of an operating segment, that constitute a business for which discrete financial information is available and for which segment management regularly reviews the operating results. For more information on the Company's operating segments, see Note 17. Goodwill impairment, if any, is measured by comparing the fair value of each reporting unit to its carrying value. If the fair value of a reporting unit exceeds its carrying value, the goodwill of the reporting unit is not impaired. If the carrying value of a reporting unit exceeds its fair value, the Company must record an impairment loss for the amount that the carrying value of the reporting unit, including goodwill, exceeds the fair value of the reporting unit. For the years ended December 31, 2022, 2021 and 2020, there were no impairment losses recorded.

Investments

The Company's investments include the cash surrender value of life insurance policies, insurance contracts, mortgage-backed securities and U.S. Treasury securities. The Company measures its investment in the insurance contracts at fair value with any unrealized gains and losses recorded on the Consolidated Statements of Income. The Company has not elected the fair value option for its mortgage-backed securities and U.S. Treasury securities and, as a result, the unrealized gains and losses on these investments are recorded in accumulated other comprehensive loss. For more information, see Notes 8 and 18.

Government Assistance

The Company accounts for government assistance received for capital projects by reducing the cost of the project by the amount of assistance received. The Company records government assistance received as taxable income and writes-up the tax basis of the asset to include the amount of the assistance received.

Government assistance received for the years ended December 31, 2022, 2021 and 2020, was immaterial.

Variable interest entities

The Company evaluates its arrangements and contracts with other entities to determine if they are VIEs and if so, if the Company is the primary beneficiary. GAAP provides a framework for identifying VIEs and determining when a company should include the assets, liabilities, noncontrolling interest and results of activities of a VIE in its consolidated financial statements.

A VIE should be consolidated if a party with an ownership, contractual or other financial interest in the VIE (a variable interest holder) has the power to direct the VIE's most significant activities and the obligation to absorb losses or right to receive benefits of the VIE that could be significant to the VIE. A variable interest holder that consolidates the VIE is called the primary beneficiary. Upon consolidation, the primary beneficiary generally must initially record all of the VIE's assets, liabilities and noncontrolling interests at fair value and subsequently account for the VIE as if it were consolidated.

The Company's evaluation of whether it qualifies as the primary beneficiary of a VIE involves significant judgments, estimates and assumptions and includes a qualitative analysis of the activities that most significantly impact the VIE's economic performance and whether the Company has the power to direct those activities, the design of the entity, the rights of the parties and the purpose of the arrangement.

Joint ventures

The Company accounts for unconsolidated joint ventures using either the equity method or proportionate consolidation. The Company currently holds interests between 25 percent and 50 percent in joint ventures formed primarily for the purpose of pooling resources on construction contracts. Proportionate consolidation is used for joint ventures that include unincorporated legal entities and activities of the joint venture which are construction-related. For those joint ventures accounted for under proportionate consolidation, only the Company’s pro rata share of assets, liabilities, revenues and expenses are included in the Company’s balance sheet and results of operations.

For those joint ventures accounted for using proportionate consolidation, the Company recorded in its Consolidated Statements of Income $14.8 million, $14.7 million, and $69.7 million of revenue for the years ended December 31, 2022, 2021 and 2020, respectively, and $3.0 million, $4.7 million and $20.6 million of operating income for the years ended December 31, 2022, 2021 and 2020, respectively. At December 31, 2022 and 2021, the Company had interest in assets from these joint ventures of $2.4 million and $14.3 million, respectively.

For those joint ventures accounted for under the equity method, the Company's investment balances for the joint venture is included in Investments in the Consolidated Balance Sheets and the Company’s pro rata share of net income is included in Other income in the Consolidated Statements of Income. The Company’s investments in equity method joint ventures were a net asset of $1.3 million for both December 31, 2022 and 2021, respectively. In 2022, 2021 and 2020, the Company recognized income (loss) from equity method joint ventures of $5.4 million, $892,000 and $(32,000), respectively.

Derivative instruments

The Company enters into commodity price derivative contracts in order to minimize the price volatility associated with customer natural gas costs at its natural gas distribution segment. These derivatives are not designated as hedging instruments and are recorded in the Consolidated Balance Sheets at fair value. Changes in the fair value of these derivatives along with any contract settlements are recorded each period in regulatory assets or liabilities in accordance with regulatory accounting. The Company does not enter into any derivatives for trading or other speculative purposes.

During 2022, the Company did not enter into any commodity price derivative contracts. During 2021, the Company entered into commodity price derivative contracts securing the purchase of 450,000 MMBtu of natural gas.

Leases

Lease liabilities and their corresponding right-of-use assets are recorded based on the present value of lease payments over the expected lease term. The Company recognizes leases with an original lease term of 12 months or less in income on a straight-line basis over the term of the lease and does not recognize a corresponding right-of-use asset or lease liability. The Company determines the lease term based on the non-cancelable and cancelable periods in each contract. The non-cancelable period consists of the term of the contract that is legally enforceable and cannot be canceled by either party without incurring a significant penalty. The cancelable period is determined by various factors that are based on who has the right to cancel a contract. If only the lessor has the right to cancel the contract, the Company will assume the contract will continue. If the lessee is the only party that has the right to cancel the contract, the Company looks to asset, entity and market-based factors. If both the lessor and the lessee have the right to cancel the contract, the Company assumes the contract will not continue.

The discount rate used to calculate the present value of the lease liabilities is based upon the implied rate within each contract. If the rate is unknown or cannot be determined, the Company uses an incremental borrowing rate, which is determined by the length of the contract, asset class and the Company's borrowing rates, as of the commencement date of the contract.

Asset retirement obligations

The Company records the fair value of a liability for an asset retirement obligation in the period in which it is incurred. When the liability is initially recorded, the Company capitalizes a cost by increasing the carrying amount of the related long-lived asset. Over time, the liability is accreted to its present value each period and the capitalized cost is depreciated over the useful life of the related asset. Upon settlement of the liability, the Company either settles the obligation for the recorded amount or incurs a gain or loss at its non-regulated operations or incurs a regulatory asset or liability at its regulated operations.

Stock-based compensation

The Company determines compensation expense for stock-based awards based on the estimated fair values at the grant date and recognizes the related compensation expense over the vesting period. The Company uses the straight-line amortization method to recognize compensation expense related to restricted stock, which only has a service condition. This method recognizes stock compensation expense on a straight-line basis over the requisite service period for the entire award. The Company recognizes compensation expense related to performance awards that vest based on performance metrics and service conditions on a straight-line basis over the service period. Inception-to-date expense is adjusted based upon the determination of the potential achievement of the performance target at each reporting date. The Company recognizes compensation expense related to performance awards with market-based performance metrics on a straight-line basis over the requisite service period.

The Company records the compensation expense for performance share awards using an estimated forfeiture rate. The estimated forfeiture rate is calculated based on an average of actual historical forfeitures. The Company also performs an analysis of any known factors at the time of the calculation to identify any necessary adjustments to the average historical forfeiture rate. At the time actual forfeitures become more than estimated forfeitures, the Company records compensation expense using actual forfeitures.

Earnings per share

Basic earnings per share is computed by dividing net income by the weighted average number of shares of common stock outstanding during the year. Diluted earnings per share is computed by dividing net income by the total of the weighted average number of shares of common stock outstanding during the year, plus the effect of nonvested performance share awards and restricted stock units. Common stock outstanding includes issued shares less shares held in treasury. Net income was the same for both the basic and diluted earnings per share calculations. A reconciliation of the weighted average common shares outstanding used in the basic and diluted earnings per share calculations follows:

	2022	2021	2020
		(In thousands)	
Weighted average common shares outstanding - basic	**203,358**	202,076	200,502
Effect of dilutive performance share awards	**104**	307	69
Weighted average common shares outstanding - diluted	**203,462**	202,383	200,571
Shares excluded from the calculation of diluted earnings per share	**14**	—	164

Income taxes

The Company provides deferred federal and state income taxes on all temporary differences between the book and tax basis of the Company's assets and liabilities by 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 period that includes the enactment date. Excess deferred income tax balances associated with the Company's rate-regulated activities have been recorded as regulatory liabilities. These regulatory liabilities are expected to be reflected as a reduction in future rates charged to customers in accordance with applicable regulatory procedures.

The Company uses the deferral method of accounting for investment tax credits and amortizes the credits on regulated electric and natural gas distribution plant over various periods that conform to the ratemaking treatment prescribed by the applicable state public service commissions.

The Company records uncertain tax positions in accordance with accounting guidance on accounting for income taxes on the basis of a two-step process in which (1) the Company determines whether it is more-likely-than-not that the tax position will be sustained on the basis of the technical merits of the position and (2) for those tax positions that meet the more-likely-than-not recognition threshold, the Company recognizes the largest amount of the tax benefit that is more than 50 percent likely to be realized upon ultimate settlement with the related tax authority. Tax positions that do not meet the more-likely-than-not criteria are reflected as a tax liability. The Company recognizes interest and penalties accrued related to unrecognized tax benefits in income taxes.

Note 3 - Revenue from Contracts with Customers

Revenue is recognized when a performance obligation is satisfied by transferring control over a product or service to a customer. Revenue is measured based on consideration specified in a contract with a customer and excludes any sales incentives and amounts collected on behalf of third parties. The Company is considered an agent for certain taxes collected from customers. As such, the Company presents revenues net of these taxes at the time of sale to be remitted to governmental authorities, including sales and use taxes.

As part of the adoption of ASC 606 - *Revenue from Contracts with Customers*, the Company elected the practical expedient to recognize the incremental costs of obtaining a contract as an expense when incurred if the amortization period of the asset that the Company otherwise would have recognized is 12 months or less.

Disaggregation

In the following table, revenue is disaggregated by the type of customer or service provided. The Company believes this level of disaggregation best depicts how the nature, amount, timing and uncertainty of revenue and cash flows are affected by economic factors. The table also includes a reconciliation of the disaggregated revenue by reportable segments. For more information on the Company's business segments, see Note 17.

Year ended December 31, 2022	Electric	Natural gas distribution	Pipeline	Construction materials and contracting	Construction services	Other	Total
				(In thousands)			
Residential utility sales	$ 138,634	$ 718,191	$ —	$ —	$ —	$ —	$ 856,825
Commercial utility sales	146,182	453,802	—	—	—	—	599,984
Industrial utility sales	43,766	41,710	—	—	—	—	85,476
Other utility sales	7,597	—	—	—	—	—	7,597
Natural gas transportation	—	48,886	129,290	—	—	—	178,176
Natural gas storage	—	—	14,583	—	—	—	14,583
Contracting services	—	—	—	1,187,721	—	—	1,187,721
Construction materials	—	—	—	1,940,890	—	—	1,940,890
Internal sales	—	—	—	(593,882)	—	—	(593,882)
Electrical & mechanical specialty contracting	—	—	—	—	1,988,729	—	1,988,729
Transmission & distribution specialty contracting	—	—	—	—	662,705	—	662,705
Other	45,608	13,617	11,450	—	436	17,605	88,716
Intersegment eliminations	(494)	(555)	(59,012)	(1,016)	(5,494)	(17,605)	(84,176)
Revenues from contracts with customers	381,293	1,275,651	96,311	2,533,713	2,646,376	—	6,933,344
Other revenues	(4,714)	(2,402)	256	—	47,380	—	40,520
Total external operating revenues	$ 376,579	$ 1,273,249	$ 96,567	$ 2,533,713	$ 2,693,756	$ —	$ 6,973,864

Year ended December 31, 2021	Electric	Natural gas distribution	Pipeline	Construction materials and contracting	Construction services	Other	Total
				(In thousands)			
Residential utility sales	$ 126,841	$ 544,721	$ —	$ —	$ —	$ —	$ 671,562
Commercial utility sales	137,556	328,285	—	—	—	—	465,841
Industrial utility sales	41,757	30,964	—	—	—	—	72,721
Other utility sales	7,051	—	—	—	—	—	7,051
Natural gas transportation	—	48,408	114,001	—	—	—	162,409
Natural gas storage	—	—	14,680	—	—	—	14,680
Contracting services	—	—	—	1,017,471	—	—	1,017,471
Construction materials	—	—	—	1,712,503	—	—	1,712,503
Internal sales	—	—	—	(501,044)	—	—	(501,044)
Electrical & mechanical specialty contracting	—	—	—	—	1,324,419	—	1,324,419
Transmission & distribution specialty contracting	—	—	—	—	677,074	—	677,074
Other	42,902	10,567	13,667	—	557	13,714	81,407
Intersegment eliminations	(543)	(576)	(59,678)	(624)	(2,555)	(13,630)	(77,606)
Revenues from contracts with customers	355,564	962,369	82,670	2,228,306	1,999,495	84	5,628,488
Other revenues	(6,525)	8,995	188	—	49,587	—	52,245
Total external operating revenues	$ 349,039	$ 971,364	$ 82,858	$ 2,228,306	$ 2,049,082	$ 84	$ 5,680,733

Year ended December 31, 2020	Electric	Natural gas distribution	Pipeline	Construction materials and contracting	Construction services	Other	Total
				(In thousands)			
Residential utility sales	$ 122,663	$ 476,388	$ —	$ —	$ —	$ —	$ 599,051
Commercial utility sales	131,477	277,873	—	—	—	—	409,350
Industrial utility sales	36,744	26,243	—	—	—	—	62,987
Other utility sales	6,634	—	—	—	—	—	6,634
Natural gas transportation	—	45,546	111,686	—	—	—	157,232
Natural gas gathering	—	—	4,865	—	—	—	4,865
Natural gas storage	—	—	14,918	—	—	—	14,918
Contracting services	—	—	—	1,069,665	—	—	1,069,665
Construction materials	—	—	—	1,659,152	—	—	1,659,152
Internal sales	—	—	—	(550,815)	—	—	(550,815)
Electrical & mechanical specialty contracting	—	—	—	—	1,397,124	—	1,397,124
Transmission & distribution specialty contracting	—	—	—	—	649,486	—	649,486
Other	32,452	10,753	12,216	—	1,541	11,903	68,865
Intersegment eliminations	(491)	(534)	(58,531)	(417)	(5,038)	(11,958)	(76,969)
Revenues from contracts with customers	329,479	836,269	85,154	2,177,585	2,043,113	(55)	5,471,545
Other revenues	2,059	11,382	192	—	47,572	—	61,205
Total external operating revenues	$ 331,538	$ 847,651	$ 85,346	$ 2,177,585	$ 2,090,685	$ (55)	$ 5,532,750

Presented in the previous tables are sales of materials to both third parties and internal customers within the construction materials and contracting segment to highlight the focus on vertical integration as this segment sells materials to both third parties and internal customers. Due to consolidation requirements, the internal sales revenues must be eliminated against the construction materials product used in the contracting services to arrive at the external operating revenue total for the segment.

Contract balances

The timing of revenue recognition may differ from the timing of invoicing to customers. The timing of invoicing to customers does not necessarily correlate with the timing of revenues being recognized under the cost-to-cost method of accounting. Contracts from contracting services are billed as work progresses in accordance with agreed upon contractual terms. Generally, billing to the customer occurs contemporaneous to revenue recognition. A variance in timing of the billings may result in a contract asset or a contract liability. A contract asset occurs when revenues are recognized under the cost-to-cost measure of progress, which exceeds amounts billed on uncompleted contracts. Such amounts will be billed as standard contract terms allow, usually based on various measures of performance or achievement. A contract liability occurs when there are billings in excess of revenues recognized under the cost-to-cost measure of progress on uncompleted contracts. Contract liabilities decrease as revenue is recognized from the satisfaction of the related performance obligation.

The changes in contract assets and liabilities were as follows:

	December 31, 2022	December 31, 2021	Change	Location on Consolidated Balance Sheets
	(In thousands)			
Contract assets	$ 185,289	$ 125,742	$ 59,547	Receivables, net
Contract liabilities - current	(208,204)	(179,140)	(29,064)	Accounts payable
Contract liabilities - noncurrent	(6)	(118)	112	Noncurrent liabilities - other
Net contract liabilities	$ (22,921)	$ (53,516)	$ 30,595	

	December 31, 2021	December 31, 2020	Change	Location on Consolidated Balance Sheets
	(In thousands)			
Contract assets	$ 125,742	$ 104,345	$ 21,397	Receivables, net
Contract liabilities - current	(179,140)	(158,603)	(20,537)	Accounts payable
Contract liabilities - noncurrent	(118)	(52)	(66)	Noncurrent liabilities - other
Net contract liabilities	$ (53,516)	$ (54,310)	$ 794	

The Company recognized $173.8 million and $155.0 million in revenue for the years ended December 31, 2022 and 2021, respectively, which was previously included in contract liabilities at December 31, 2021 and 2020, respectively.

The Company recognized a net increase in revenues of $57.9 million and $66.3 million for the years ended December 31, 2022 and 2021, respectively, from performance obligations satisfied in prior periods.

Remaining performance obligations

The remaining performance obligations, also referred to as backlog, at the construction materials and contracting and construction services segments include unrecognized revenues that the Company reasonably expects to be realized. These unrecognized revenues can include: projects that have a written award, a letter of intent, a notice to proceed, an agreed upon work order to perform work on mutually accepted terms and conditions and change orders or claims to the extent management believes additional contract revenues will be earned and are deemed probable of collection. Excluded from remaining performance obligations are potential orders under master service agreements. The majority of the Company's construction contracts have an original duration of less than two years.

The remaining performance obligations at the pipeline segment include firm transportation and storage contracts with fixed pricing and fixed volumes. The Company has applied the practical expedient that does not require additional disclosures for contracts with an original duration of less than 12 months to certain firm transportation and non-regulated contracts. The Company's firm transportation contracts included in the remaining performance obligations have weighted average remaining durations of less than five years.

At December 31, 2022, the Company's remaining performance obligations were $3.5 billion. The Company expects to recognize the following revenue amounts in future periods related to these remaining performance obligations: $2.7 billion within the next 12 months or less; $411.8 million within the next 13 to 24 months; and $429.1 million in 25 months or more.

Note 4 - Business Combinations

The following acquisitions were accounted for as business combinations in accordance with ASC 805 - *Business Combinations.* The results of the business combinations have been included in the Company's Consolidated Financial Statements beginning on the acquisition date. Pro forma financial amounts reflecting the effects of the business combinations are not presented, as none of these business combinations, individually or in the aggregate, were material to the Company's financial position or results of operations.

The acquisitions are also subject to customary adjustments based on, among other things, the amount of cash, debt and working capital in the business as of the closing date. The amounts included in the Consolidated Balance Sheets for these adjustments are considered provisional until final settlement has occurred.

In 2022 and 2021, the construction materials and contracting segment's acquisitions included:

- Allied Concrete and Supply Co., a producer of ready-mixed concrete in California, acquired in December 2022. At December 31, 2022, the purchase price allocation was preliminary and will be finalized within 12 months of the acquisition date.
- Baker Rock Resources and Oregon Mainline Paving, two construction materials companies located around the Portland, Oregon metro area, acquired in November 2021. As of September 30, 2022, the purchase price allocation was settled with no material adjustments to the provisional accounting.

- Mt. Hood Rock, a construction aggregates business in Oregon, acquired in April 2021. As of March 31, 2022, the purchase price allocation was settled with no material adjustments to the provisional accounting.

The total purchase price for acquisitions that occurred in 2022 was $8.9 million, subject to certain adjustments, with cash acquired totaling $2.8 million. The purchase price includes consideration paid of $1.5 million, a $70,000 holdback liability, and 273,153 shares of common stock with a market value of $8.4 million as of the respective acquisition date. Due to the holding period restriction on the common stock, the share consideration has been discounted to a fair value of approximately $7.3 million. The amounts allocated to the aggregated assets acquired and liabilities assumed during 2022 were as follows: $1.7 million to current assets; $5.9 million to property, plant and equipment; $200,000 to goodwill; $100,000 to current liabilities; $500,000 to noncurrent liabilities - other and $1.2 million to deferred tax liabilities.

The total purchase price for acquisitions that occurred in 2021 was $236.1 million, subject to certain adjustments, with cash acquired totaling $900,000. The purchase price includes consideration paid of $235.2 million. The amounts allocated to the aggregated assets acquired and liabilities assumed during 2021 were as follows: $17.0 million to current assets; $179.8 million to property, plant and equipment; $50.6 million to goodwill; $2.2 million to other intangible assets; $8.7 million to current liabilities; $2.5 million to noncurrent liabilities - other; and $3.2 million to deferred tax liabilities. The intangible assets include non-compete agreements, customer relationships, and trade names. The intangible assets fair value is based on various income approach methods, including, multi-period excess earnings, relief-from-royalty and the with and without method. The amortizable intangible assets are being amortized using a straight-line method over a weighted average period of 5.5 years. During the first quarter of 2022, measurement period adjustments were made to the previously reported provisional amounts, which decreased goodwill and increased property, plant and equipment by $2.1 million. The Company issued debt to finance these acquisitions.

Costs incurred for acquisitions are included in operation and maintenance expense on the Consolidated Statements of Income and were immaterial for the years ended December 31, 2022, 2021 and 2020.

Note 5 - Property, Plant and Equipment

Property, plant and equipment at December 31 was as follows:

	2022	2021	Weighted Average Depreciable Life in Years
	(Dollars in thousands, where applicable)		
Regulated:			
Electric:			
Generation	**$ 938,614**	$ 1,056,632	48
Distribution	**489,351**	474,037	47
Transmission	**616,611**	562,080	65
Construction in progress	**87,003**	62,781	—
Other	**145,034**	140,117	14
Natural gas distribution:			
Distribution	**2,569,921**	2,427,779	52
Transmission	**104,769**	107,721	61
Storage	**42,318**	34,997	37
General	**204,993**	197,653	13
Construction in progress	**55,759**	21,741	—
Other	**230,299**	225,272	15
Pipeline:			
Transmission	**951,187**	673,344	46
Storage	**55,383**	57,670	53
Construction in progress	**34,655**	263,640	—
Other	**59,917**	50,477	19
Non-regulated:			
Pipeline:			
Construction in progress	**49**	18	—
Other	**6,950**	6,719	10
Construction materials and contracting:			
Land	**150,809**	149,066	—
Buildings and improvements	**165,833**	149,262	21
Machinery, vehicles and equipment	**1,492,506**	1,414,260	12
Construction in progress	**88,163**	50,425	—
Aggregate reserves	**592,097**	584,683	*
Construction services:			
Land	**8,234**	6,513	—
Buildings and improvements	**50,776**	39,039	24
Machinery, vehicles and equipment	**179,459**	166,739	7
Other	**6,643**	13,467	4
Other:			
Land	**2,648**	2,648	—
Other	**34,057**	34,069	7
Less accumulated depreciation, depletion and amortization	**3,272,493**	3,216,461	
Net property, plant and equipment	**$ 6,091,545**	$ 5,756,388	

* Depleted on the units-of-production method based on proven and probable aggregate reserves.

Note 6 - Regulatory Assets and Liabilities

The following table summarizes the individual components of unamortized regulatory assets and liabilities as of December 31:

	Estimated Recovery or Refund Period *	**2022**	2021
		(In thousands)	
Regulatory assets:			
Current:			
Natural gas costs recoverable through rate adjustments	Up to 1 year	**$ 141,306**	$ 86,371
Conservation programs	Up to 1 year	**8,544**	8,225
Cost recovery mechanisms	Up to 1 year	**4,019**	4,536
Decoupling	Up to 1 year	**1,801**	9,131
Other	Up to 1 year	**9,422**	10,428
		165,092	118,691
Noncurrent:			
Pension and postretirement benefits	**	**143,349**	142,681
Cost recovery mechanisms	Up to 10 years	**67,171**	44,870
Plant costs/asset retirement obligations	Over plant lives	**44,462**	63,116
Manufactured gas plant sites remediation	-	**26,624**	26,053
Plant to be retired	-	**21,525**	50,070
Taxes recoverable from customers	Over plant lives	**12,330**	12,339
Long-term debt refinancing costs	Up to 38 years	**3,188**	3,794
Natural gas costs recoverable through rate adjustments	Up to 2 years	**—**	5,186
Other	Up to 16 years	**11,010**	9,742
		329,659	357,851
Total regulatory assets		**$ 494,751**	$ 476,542
Regulatory liabilities:			
Current:			
Electric fuel and purchased power deferral	Up to 1 year	**$ 4,929**	$ —
Conservation programs	Up to 1 year	**4,126**	12
Taxes refundable to customers	Up to 1 year	**3,937**	3,841
Refundable fuel & electric costs	Up to 1 year	**3,253**	713
Natural gas costs refundable through rate adjustments	Up to 1 year	**955**	6,700
Other	Up to 1 year	**9,240**	5,037
		26,440	16,303
Noncurrent:			
Plant removal and decommissioning costs	Over plant lives	**208,650**	168,152
Taxes refundable to customers	Over plant lives	**203,222**	215,421
Cost recovery mechanisms	Up to 19 years	**14,025**	2,919
Accumulated deferred investment tax credit	Up to 19 years	**13,594**	12,696
Pension and postretirement benefits	**	**7,376**	20,434
Other	Up to 15 years	**1,587**	9,168
		448,454	428,790
Total regulatory liabilities		**$ 474,894**	$ 445,093
Net regulatory position		**$ 19,857**	$ 31,449

* Estimated recovery or refund period for amounts currently being recovered or refunded in rates to customers.

** Recovered as expense is incurred or cash contributions are made.

As of December 31, 2022 and 2021, approximately $242.5 million and $296.6 million, respectively, of regulatory assets were not earning a rate of return but are expected to be recovered from customers in future rates. These assets are largely comprised of the unfunded portion of pension and postretirement benefits, asset retirement obligations, accelerated depreciation on plant retirement and the estimated future cost of manufactured gas plant site remediation.

In the last half of 2021 and in 2022, the Company has experienced higher natural gas costs due to increase in demand outpacing the supply along with the impact of global events. This increase in natural gas costs experienced in certain jurisdictions has been partially offset by the recovery of prior period natural gas costs being recovered over a period longer than the normal one-year period.

In February 2019, the Company announced the retirement of three aging coal-fired electric generating units. The Company accelerated the depreciation related to these facilities in property, plant and equipment and recorded the difference between the accelerated depreciation, in accordance with GAAP, and the depreciation approved for rate-making purposes as regulatory assets. Requests were filed with the NDPSC and SDPUC, and subsequently approved, to offset the savings associated with the cessation of operations of these units with the amortization of the deferred regulatory assets. The Company ceased operations of Lewis & Clark Station in March 2021 and Units 1 and 2 at Heskett Station in February 2022. The Company subsequently reclassified the costs being recovered for these facilities from plant retirement to cost recovery mechanisms in the previous table and began amortizing the associated plant retirement and closure costs in the jurisdictions where requests were filed, as previously discussed. The Company expects to recover the regulatory assets related to the plant retirements in future rates.

If, for any reason, the Company's regulated businesses cease to meet the criteria for application of regulatory accounting for all or part of their operations, the regulatory assets and liabilities relating to those portions ceasing to meet such criteria would be removed from the balance sheet and included in the statement of income or accumulated other comprehensive loss in the period in which the discontinuance of regulatory accounting occurs.

Note 7 - Goodwill and Other Intangible Assets

The changes in the carrying amount of goodwill were as follows:

	Balance at January 1, 2022	Goodwill Acquired During the Year	Measurement Period Adjustments	Balance at December 31, 2022
	(In thousands)			
Natural gas distribution	$ 345,736	$ —	$ —	$ 345,736
Construction materials and contracting	276,426	238	(2,124)	274,540
Construction services	143,224	—	—	143,224
Total	$ 765,386	$ 238	$ (2,124)	$ 763,500

	Balance at January 1, 2021	Goodwill Acquired During the Year	Measurement Period Adjustments	Balance at December 31, 2021
	(In thousands)			
Natural gas distribution	$ 345,736	$ —	$ —	$ 345,736
Construction materials and contracting	226,003	50,640	(217)	276,426
Construction services	143,224	—	—	143,224
Total	$ 714,963	$ 50,640	$ (217)	$ 765,386

Other amortizable intangible assets at December 31 were as follows:

	2022	2021
	(In thousands)	
Customer relationships	**$ 28,990**	$ 29,740
Less accumulated amortization	**13,724**	10,650
	15,266	19,090
Noncompete agreements	**4,591**	4,591
Less accumulated amortization	**3,529**	2,856
	1,062	1,735
Other	**5,280**	12,601
Less accumulated amortization	**4,076**	10,848
	1,204	1,753
Total	**$ 17,532**	$ 22,578

The previous tables include goodwill and intangible assets associated with the business combinations completed during 2022 and 2021. For more information related to these business combinations, see Note 4.

Amortization expense for amortizable intangible assets for the years ended December 31, 2022, 2021 and 2020, was $5.0 million, $5.1 million and $9.0 million, respectively. The amounts of estimated amortization expense for identifiable intangible assets as of December 31, 2022, were:

	2023	2024	2025	2026	2027	Thereafter
			(In thousands)			
Amortization expense	$ 4,591	$ 4,249	$ 2,200	$ 1,782	$ 1,759	$ 2,951

At October 31, 2022, the fair value substantially exceeded the carrying value at the Company's reporting units with goodwill, with the exception of the natural gas distribution reporting unit. The Company's annual impairment testing indicated the natural gas distribution reporting units fair value is not substantially in excess of its carrying value ("cushion"). Based on the Company's assessment, the estimated fair value of the natural gas distribution reporting unit exceeded its carrying value, which includes $345.7 million of goodwill, by approximately 8 percent as of October 31, 2022. The decrease in the natural gas distribution reporting unit's cushion from the prior year was primarily attributable to the risk adjusted cost of capital increasing from 5.0 percent in 2021 to 6.4 percent 2022, which directly correlates with the treasury rates at the date of the test. The natural gas distribution reporting unit is at risk of future impairment if projected operating results are not met or other inputs into the fair value measurement model change.

Note 8 - Fair Value Measurements

Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability (an exit price) in an orderly transaction between market participants at the measurement date. The fair value ASC establishes a hierarchy for grouping assets and liabilities, based on the significance of inputs. The estimated fair values of the Company's assets and liabilities measured on a recurring basis are determined using the market approach.

The Company measures its investments in certain fixed-income and equity securities at fair value with changes in fair value recognized in income. The Company anticipates using these investments, which consist of insurance contracts, to satisfy its obligations under its unfunded, nonqualified defined benefit and defined contribution plans for the Company's executive officers and certain key management employees, and invests in these fixed-income and equity securities for the purpose of earning investment returns and capital appreciation. These investments, which totaled $98.0 million and $109.6 million at December 31, 2022 and 2021, respectively, are classified as investments on the Consolidated Balance Sheets. The net unrealized losses on these investments for the year ended December 31, 2022, were $14.1 million. The net unrealized gains on these investments for the years ended December 31, 2021 and 2020, were $7.2 million and $13.1 million, respectively. The change in fair value, which is considered part of the cost of the plan, is classified in other income on the Consolidated Statements of Income.

The Company did not elect the fair value option, which records gains and losses in income, for its available-for-sale securities, which include mortgage-backed securities and U.S. Treasury securities. These available-for-sale securities are recorded at fair value and are classified as investments on the Consolidated Balance Sheets. Unrealized gains or losses are recorded in accumulated other comprehensive loss. Details of available-for-sale securities were as follows:

December 31, 2022	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
		(In thousands)		
Mortgage-backed securities	$ 8,928	$ 2	$ 636	$ 8,294
U.S. Treasury securities	2,608	—	72	2,536
Total	$ 11,536	$ 2	$ 708	$ 10,830

December 31, 2021	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
		(In thousands)		
Mortgage-backed securities	$ 8,702	$ 51	$ 47	$ 8,706
U.S. Treasury securities	2,407	—	11	2,396
Total	$ 11,109	$ 51	$ 58	$ 11,102

The Company's assets measured at fair value on a recurring basis were as follows:

	Fair Value Measurements at December 31, 2022, Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at December 31, 2022
		(In thousands)		
Assets:				
Money market funds	$ —	$ 7,361	$ —	$ 7,361
Insurance contracts*	—	98,041	—	98,041
Available-for-sale securities:				
Mortgage-backed securities	—	8,294	—	8,294
U.S. Treasury securities	—	2,536	—	2,536
Total assets measured at fair value	$ —	$ 116,232	$ —	$ 116,232

* The insurance contracts invest approximately 63 percent in fixed-income investments, 15 percent in common stock of large-cap companies, 8 percent in common stock of mid-cap companies, 6 percent in common stock of small-cap companies, 6 percent in target date investments and 2 percent in cash equivalents.

	Fair Value Measurements at December 31, 2021, Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at December 31, 2021
		(In thousands)		
Assets:				
Money market funds	$ —	$ 10,190	$ —	$ 10,190
Insurance contracts*	—	109,603	—	109,603
Available-for-sale securities:				
Mortgage-backed securities	—	8,706	—	8,706
U.S. Treasury securities	—	2,396	—	2,396
Total assets measured at fair value	$ —	$ 130,895	$ —	$ 130,895

* The insurance contracts invest approximately 61 percent in fixed-income investments, 17 percent in common stock of large-cap companies, 8 percent in common stock of mid-cap companies, 7 percent in common stock of small-cap companies, 5 percent in target date investments and 2 percent in cash equivalents.

The Company's money market funds are valued at the net asset value of shares held at the end of the period, based on published market quotations on active markets, or using other known sources including pricing from outside sources. The estimated fair value of the Company's mortgage-backed securities and U.S. Treasury securities are based on comparable market transactions, other observable inputs or other sources, including pricing from outside sources. The estimated fair value of the Company's insurance contracts is based on contractual cash surrender values that are determined primarily by investments in managed separate accounts of the insurer. These amounts approximate fair value. The managed separate accounts are valued based on other observable inputs or corroborated market data.

Though the Company believes the methods used to estimate fair value are consistent with those used by other market participants, the use of other methods or assumptions could result in a different estimate of fair value.

The Company applies the provisions of the fair value measurement standard to its nonrecurring, non-financial measurements, including long-lived asset impairments. These assets are not measured at fair value on an ongoing basis but are subject to fair value adjustments only in certain circumstances. The Company reviews the carrying value of its long-lived assets, excluding goodwill, whenever events or changes in circumstances indicate that such carrying amounts may not be recoverable.

The Company performed a fair value assessment of the assets acquired and liabilities assumed in the business combinations that occurred during 2022 and 2021. For more information on these Level 2 and Level 3 fair value measurements, see Notes 2 and 4.

The Company's long-term debt is not measured at fair value on the Consolidated Balance Sheets and the fair value is being provided for disclosure purposes only. The fair value was categorized as Level 2 in the fair value hierarchy and was based on discounted future cash flows using current market interest rates. The estimated fair value of the Company's Level 2 long-term debt at December 31 was as follows:

	2022	2021
	(In thousands)	
Carrying Amount	**$ 2,841,425**	$ 2,741,900
Fair Value	**$ 2,469,625**	$ 2,984,866

The carrying amounts of the Company's remaining financial instruments included in current assets and current liabilities approximate their fair values.

Note 9 - Debt

Certain debt instruments of the Company's subsidiaries contain restrictive and financial covenants and cross-default provisions. In order to borrow under the respective debt instruments, the subsidiary companies must be in compliance with the applicable covenants and certain other conditions, all of which the subsidiaries, as applicable, were in compliance with at December 31, 2022. In the event the subsidiaries do not comply with the applicable covenants and other conditions, alternative sources of funding may need to be pursued.

The following table summarizes the outstanding revolving credit facilities of the Company's subsidiaries:

Company	Facility	Facility Limit		Amount Outstanding at December 31, 2022	Amount Outstanding at December 31, 2021	Letters of Credit at December 31, 2022		Expiration Date
					(In millions)			
Montana-Dakota Utilities Co.	Commercial paper/Revolving credit agreement (a)	$ 175.0		$ 117.5	$ 64.9	$ —		12/19/24
Cascade Natural Gas Corporation	Revolving credit agreement	$ 100.0	(b)	$ 44.4	$ 71.0	$ 2.2	(c)	11/30/27
Intermountain Gas Company	Revolving credit agreement	$ 100.0	(d)	$ 85.6	$ 56.5	$ —		10/13/27
Centennial Energy Holdings, Inc.	Commercial paper/Revolving credit agreement (e)	$ 600.0		$ 298.0	$ 385.4	$ —		12/19/24

(a) The commercial paper program is supported by a revolving credit agreement with various banks (provisions allow for increased borrowings, at the option of Montana-Dakota on stated conditions, up to a maximum of $225.0 million). At December 31, 2022 and 2021, there were no amounts outstanding under the revolving credit agreement.
(b) Certain provisions allow for increased borrowings, up to a maximum of $125.0 million.
(c) Outstanding letter(s) of credit reduce the amount available under the credit agreement.
(d) Certain provisions allow for increased borrowings, up to a maximum of $125.0 million.
(e) The commercial paper program is supported by a revolving credit agreement with various banks (provisions allow for increased borrowings, at the option of Centennial on stated conditions, up to a maximum of $700.0 million). At December 31, 2022 and 2021, there were no amounts outstanding under the revolving credit agreement.

The respective commercial paper programs are supported by revolving credit agreements. While the amount of commercial paper outstanding does not reduce available capacity under the respective revolving credit agreements, Montana-Dakota and Centennial do not issue commercial paper in an aggregate amount exceeding the available capacity under their credit agreements. The commercial paper borrowings may vary during the period, largely the result of fluctuations in working capital requirements due to the seasonality of certain operations of the Company's subsidiaries.

Short-term debt

MDU Energy Capital On October 21, 2022, MDU Energy Capital entered into a $11.5 million term loan agreement with a SOFR-based variable interest rate and a maturity date of July 21, 2023. The agreement contains customary covenants and provisions, including a covenant of MDU Energy Capital not to permit, at any time, the ratio of total debt to total capitalization to be greater than 70 percent. The covenants also include certain restrictions on the sale of certain assets, loans and investments.

Centennial On March 18, 2022, Centennial entered into a $100.0 million term loan agreement with a SOFR-based variable interest rate and a maturity date of March 17, 2023. The agreement contains customary covenants and provisions, including a covenant of Centennial not to permit, at any time, the ratio of total debt to total capitalization to be greater than 65 percent. The covenants also include certain restrictions on the sale of certain assets, loans and investments.

On December 19, 2022, Centennial entered into a $135.0 million term loan agreement with a SOFR-based variable interest rate and a maturity date of December 18, 2023. The agreement contains customary covenants and provisions, including a covenant of Centennial not to permit, at any time, the ratio of total debt to total capitalization to be greater than 65 percent. The covenants also include certain restrictions on the sale of certain assets, loans and investments.

Long-term debt

Long-term Debt Outstanding Long-term debt outstanding was as follows:

	Weighted Average Interest Rate at December 31, 2022	2022	2021
		(In thousands)	
Senior Notes due on dates ranging from May 15, 2023 to June 15, 2062	**4.32 %**	**$ 2,258,500**	$ 2,125,000
Commercial paper supported by revolving credit agreements	**5.13 %**	**415,500**	450,300
Credit agreements due on October 13, 2027 and November 30, 2027	**6.31 %**	**130,000**	127,500
Medium-Term Notes due on dates ranging from September 15, 2027 to March 16, 2029	**7.32 %**	**35,000**	35,000
Term Loan Agreement due on September 3, 2032	**3.64 %**	**7,000**	7,700
Other notes due on dates ranging from March 1, 2024 to January 1, 2061	**1.00 %**	**2,253**	2,564
Less unamortized debt issuance costs		**6,542**	6,090
Less discount		**286**	74
Total long-term debt		**2,841,425**	2,741,900
Less current maturities		**78,031**	148,053
Net long-term debt		**$ 2,763,394**	$ 2,593,847

Montana-Dakota Montana-Dakota's revolving credit agreement supports its commercial paper program. Commercial paper borrowings under this agreement are classified as long-term debt as they are intended to be refinanced on a long-term basis through continued commercial paper borrowings. The credit agreement contains customary covenants and provisions, including covenants of Montana-Dakota not to permit, as of the end of any fiscal quarter, the ratio of funded debt to total capitalization (determined on a consolidated basis) to be greater than 65 percent. Other covenants include limitations on the sale of certain assets and on the making of certain loans and investments.

Montana-Dakota's ratio of total debt to total capitalization at December 31, 2022, was 51 percent.

Cascade On November 30, 2022, Cascade amended and restated its revolving credit agreement to extend the maturity date to November 30, 2027. Any borrowings under the revolving credit agreement are classified as long-term debt as they are intended to be refinanced on a long-term basis through continued borrowings. The credit agreement contains customary covenants and provisions, including a covenant of Cascade not to permit, at any time, the ratio of total debt to total capitalization to be greater than 65 percent. Other covenants include restrictions on the sale of certain assets, limitations on indebtedness and the making of certain investments.

On June 15, 2022, Cascade issued $50.0 million of senior notes under a note purchase agreement with maturity dates ranging from June 15, 2032 to June 15, 2052, at a weighted average interest rate of 4.50 percent. The agreement contains customary covenants and provisions, including a covenant of Cascade not to permit, at any time, the ratio of debt to total capitalization to be greater than 65 percent. Other covenants include restrictions on the sale of certain assets, limitations on indebtedness and the making of certain investments.

Cascade's ratio of total debt to total capitalization at December 31, 2022, was 50 percent.

Intermountain On October 13, 2022, Intermountain amended and restated its revolving credit agreement to increase the borrowing capacity to $100.0 million and extend the maturity date to October 13, 2027. Any borrowings under the revolving credit agreement are classified as long-term debt as they are intended to be refinanced on a long-term basis through continued borrowings. The credit agreement contains customary covenants and provisions, including a covenant of Intermountain not to permit, at any time, the ratio of total debt to total capitalization to be greater than 65 percent. Other covenants include restrictions on the sale of certain assets, limitations on indebtedness and the making of certain investments.

On June 15, 2022, Intermountain issued $40.0 million of senior notes under a note purchase agreement with maturity dates ranging from June 15, 2052 to June 15, 2062, at a weighted average interest rate of 4.68 percent. The agreement contains customary covenants and provisions, including a covenant of Intermountain not to permit, at any time, the ratio of debt to total capitalization to be greater than 65 percent. Other covenants include restrictions on the sale of certain assets, limitations on indebtedness and the making of certain investments.

Intermountain's ratio of total debt to total capitalization at December 31, 2022, was 57 percent.

Centennial Centennial's revolving credit agreement supports its commercial paper program. Commercial paper borrowings under this agreement are classified as long-term debt as they are intended to be refinanced on a long-term basis through continued commercial paper borrowings. Centennial's revolving credit agreement contains customary covenants and provisions, including a covenant of Centennial not to permit, as of the end of any fiscal quarter, the ratio of total consolidated debt to total consolidated capitalization to be greater than 65 percent. Other covenants include restricted payments, restrictions on the sale of certain assets, limitations on subsidiary indebtedness, minimum consolidated net worth, limitations on priority debt and the making of certain loans and investments.

On March 23, 2022, Centennial issued $150.0 million of senior notes under a note purchase agreement with maturity dates ranging from March 23, 2032 to March 23, 2034, at a weighted average interest rate of 3.71 percent. The agreement contains customary covenants and provisions, including a covenant of Centennial not to permit, at any time, the ratio of debt to total capitalization to be greater than 60 percent. Other covenants include restrictions on the sale of certain assets, limitations on indebtedness and the making of certain investments.

Centennial's ratio of total debt to total capitalization, as defined by its debt covenants, at December 31, 2022, was 46 percent.

Certain of Centennial's financing agreements contain cross-default provisions. These provisions state that if Centennial or any subsidiary of Centennial fails to make any payment with respect to any indebtedness or contingent obligation, in excess of a specified amount, under any agreement that causes such indebtedness to be due prior to its stated maturity or the contingent obligation to become payable, the applicable agreements will be in default.

WBI Energy Transmission On December 22, 2022, WBI Energy Transmission amended its uncommitted note purchase and private shelf agreement to increase capacity to $350.0 million with an expiration date of December 22, 2025. On December 22, 2022, WBI Energy Transmission issued $40.0 million in senior notes under the private shelf agreement with a maturity date of December 22, 2030, at an interest rate of 6.67 percent. WBI Energy Transmission had $235.0 million of notes outstanding at December 31, 2022, which reduced the remaining capacity under this uncommitted private shelf agreement to $115.0 million. This agreement contains customary covenants and provisions, including a covenant of WBI Energy Transmission not to permit, as of the end of any fiscal quarter, the ratio of total debt to total capitalization to be greater than 55 percent. Other covenants include a limitation on priority debt, restrictions on the sale of certain assets and the making of certain investments.

WBI Energy Transmission's ratio of total debt to total capitalization at December 31, 2022, was 40 percent.

Schedule of Debt Maturities Long-term debt maturities, which excludes unamortized debt issuance costs and discount, for the five years and thereafter following December 31, 2022, were as follows:

	2023	2024	2025	2026	2027	Thereafter
			(In thousands)			
Long-term debt maturities	$ 78,031	$ 476,923	$ 177,802	$ 140,802	$ 230,802	$ 1,743,893

Note 10 - Leases

Most of the leases the Company enters into are for equipment, buildings, easements and vehicles as part of their ongoing operations. The Company also leases certain equipment to third parties through its utility and construction services segments. The Company determines if an arrangement contains a lease at inception of a contract and accounts for all leases in accordance with ASC 842 - *Leases.*

The recognition of leases requires the Company to make estimates and assumptions that affect the lease classification and the assets and liabilities recorded. The accuracy of lease assets and liabilities reported on the Consolidated Financial Statements depends on, among other things, management's estimates of interest rates used to discount the lease assets and liabilities to their present value, as well as the lease terms based on the unique facts and circumstances of each lease.

Lessee accounting

The leases the Company has entered into as part of its ongoing operations are considered operating leases and are recognized on the Consolidated Balance Sheets as operating lease right-of-use assets, current operating lease liabilities and noncurrent liabilities - operating lease liabilities. The corresponding lease costs are included in operation and maintenance expense on the Consolidated Statements of Income.

Generally, the leases for vehicles and equipment have a term of five years or less and buildings and easements have a longer term of up to 35 years or more. To date, the Company does not have any residual value guarantee amounts probable of being owed to a lessor, financing leases or material agreements with related parties.

The following tables provide information on the Company's operating leases at and for the years ended December 31:

	2022	2021	2020
	(In thousands)		
Lease costs:			
Short-term lease cost	**$ 160,318**	$ 132,449	$ 135,376
Operating lease cost	**44,956**	46,622	45,319
Variable lease cost	**1,739**	1,516	1,319
	$ 207,013	$ 180,587	$ 182,014

	2022	2021	2020
	(Dollars in thousands)		
Weighted average remaining lease term	**2.83 years**	2.67 years	2.73 years
Weighted average discount rate	**4.05 %**	3.54 %	4.03 %
Cash paid for amounts included in the measurement of lease liabilities	**$ 44,512**	$ 43,489	$ 45,043

The reconciliation of future undiscounted cash flows to operating lease liabilities presented on the Consolidated Balance Sheet at December 31, 2022, was as follows:

	(In thousands)
2023	$ 38,927
2024	27,825
2025	18,741
2026	11,191
2027	7,297
Thereafter	39,963
Total	143,944
Less discount	23,894
Total operating lease liabilities	$ 120,050

Lessor accounting

The Company leases certain equipment to third parties through its utility and construction services segments, which are considered short-term operating leases with terms of less than 12 months. The Company recognized revenue from operating leases of $47.9 million, $50.1 million and $48.0 million for the years ended December 31, 2022, 2021and 2020, respectively. At December 31, 2022, the Company had $9.7 million of lease receivables with a majority due within 12 months or less.

Note 11 - Asset Retirement Obligations

The Company records obligations related to retirement costs of natural gas distribution lines, natural gas transmission lines, natural gas storage wells, decommissioning of certain electric generating facilities, reclamation of certain aggregate properties, special handling and disposal of hazardous materials at certain electric generating facilities, natural gas distribution facilities and buildings, and certain other obligations as asset retirement obligations.

A reconciliation of the Company's liability, which the current portion is included in other accrued liabilities on the Consolidated Balance Sheets, for the years ended December 31 was as follows:

	2022	2021
	(In thousands)	
Balance at beginning of year	**$ 468,686**	$ 446,919
Liabilities incurred	**5,972**	12,454
Liabilities acquired	**—**	1,805
Liabilities settled	**(9,646)**	(15,155)
Accretion expense*	**23,188**	21,214
Revisions in estimates	**(77,692)**	1,449
Balance at end of year	**$ 410,508**	$ 468,686

* Includes $21.8 million and $19.6 million in 2022 and 2021, respectively, recorded to regulatory assets.

The 2022 revisions in estimates consist principally of updated asset retirement obligation costs associated with natural gas distribution and transmission lines at the natural gas distribution segment.

The Company believes that largely all expenses related to asset retirement obligations at the Company's regulated operations will be recovered in rates over time and, accordingly, defers such expenses as regulatory assets. For more information on the Company's regulatory assets and liabilities, see Note 6.

Note 12 - Equity

The Company depends on earnings and dividends from its subsidiaries to pay dividends on common stock. The Company has paid quarterly dividends for 85 consecutive years with an increase in the dividend amount for the last 32 consecutive years. For the years ended December 31, 2022, 2021 and 2020, dividends declared on common stock were $.8750, $.8550 and $.8350 per common share, respectively. Dividends on common stock are paid quarterly to the stockholders of record less than 30 days prior to the distribution date. For the years ended December 31, 2022, 2021 and 2020, the dividends declared to common stockholders were $177.9 million, $173.0 million and $167.4 million, respectively.

The declaration and payment of dividends of the Company is at the sole discretion of the board of directors. In addition, the Company's subsidiaries are generally restricted to paying dividends out of capital accounts or net assets. The following discusses the most restrictive limitations.

Pursuant to a covenant under its revolving credit agreement, Centennial may only declare or pay distributions if, as of the last day of any fiscal quarter, the ratio of Centennial's average consolidated indebtedness as of the last day of such fiscal quarter and each of the preceding three fiscal quarters to Centennial's Consolidated trailing 12 month EBITDA does not exceed 3.5 to 1. In addition, certain credit agreements and regulatory limitations of the Company's subsidiaries also contain restrictions on dividend payments. The most restrictive limitation requires the Company's subsidiaries not to permit the ratio of funded debt to capitalization to be greater than 60 percent. Based on this limitation, approximately $1.9 billion of the net assets of the Company's subsidiaries, which represents common stockholders' equity including retained earnings, would be restricted from use for dividend payments at December 31, 2022.

The Company currently has a shelf registration statement on file with the SEC, under which the Company may issue and sell any combination of common stock and debt securities. The Company may sell such securities if warranted by market conditions and the Company's capital requirements. Any public offer and sale of such securities will be made only by means of a prospectus meeting the requirements of the Securities Act and the rules and regulations thereunder.

In August 2020, the Company amended the Distribution Agreement dated February 22, 2019, with J.P. Morgan Securities LLC and MUFG Securities Americas Inc., as sales agents. This agreement, as amended, allows the offering, issuance and sale of up to 6.4 million shares of the Company's common stock in connection with an “at-the-market” offering. The common stock may be offered for sale, from time to time, in accordance with the terms and conditions of the agreement. As of December 31, 2022, the Company had capacity to issue up to 3.6 million additional shares of common stock under the "at-the-market" offering program.

Details of the Company's "at-the-market" offering activity for the years ended December 31 was as follows:

	2022	2021	
	(In millions)		
Shares issued	—	2.8	
Net proceeds *	**$ (0.1)**	$ 88.8	**

* Net proceeds include issuance costs of $149,000 and $1.2 million for the years ended December 31, 2022 and 2021, respectively.
** Net proceeds were used for capital expenditures.

The K-Plan provides participants the option to invest in the Company's common stock. For the years ended December 31, 2022, 2021 and 2020, the K-Plan purchased shares of common stock on the open market or issued original issue common stock of the Company. At December 31, 2022, there were 7.2 million shares of common stock reserved for original issuance under the K-Plan.

The Company currently has 2.0 million shares of preferred stock authorized to be issued with a $100 par value. At December 31, 2022 and 2021, there were no shares outstanding.

Note 13 - Stock-Based Compensation

The Company has stock-based compensation plans under which it is currently authorized to grant restricted stock and other stock awards. As of December 31, 2022, there were 3.4 million remaining shares available to grant under these plans. The Company either purchases shares on the open market or issues new shares of common stock to satisfy the vesting of stock-based awards.

Total stock-based compensation expense (after tax) was $8.7 million, $12.0 million and $10.8 million in 2022, 2021 and 2020, respectively. The Company uses the straight-line amortization method to recognize compensation expense related to restricted stock, which only has a service condition. The Company recognizes compensation expense related to performance awards with market-based performance metrics on a straight-line basis over the requisite service period. As of December 31, 2022, total remaining unrecognized compensation expense related to stock-based compensation was approximately $12.5 million (before income taxes) which will be amortized over a weighted average period of 1.6 years.

Stock awards

Non-employee directors receive shares of common stock in addition to and in lieu of cash payment for directors' fees. There were 40,800 shares with a fair value of $1.2 million, 41,925 shares with a fair value of $1.2 million and 45,273 shares with a fair value of $1.1 million issued to non-employee directors during the years ended December 31, 2022, 2021 and 2020, respectively.

Restricted stock awards

In February 2022 and 2021, key employees were granted restricted stock awards under the long-term performance-based incentive plan. The shares vest over three years, contingent on continued employment. Compensation expense is recognized over the vesting period. At December 31, 2022, the number of outstanding shares granted was 188,499 with a weighted average grant-date fair value of $27.54 per share.

Performance share awards

Since 2003, key employees of the Company have been granted performance share awards each year under the long-term performance-based incentive plan authorized by the Company's compensation committee. The compensation committee has the authority to select the recipients of awards, determine the type and size of awards, and establish certain terms and conditions of award grants. Share awards are generally earned over a three-year vesting period and tied to financial metrics. Upon vesting, participants receive dividends that accumulate during the vesting period.

Target grants of performance shares outstanding at December 31, 2022, were as follows:

Grant Date	Performance Period	Target Grant of Shares
February 2021	2021-2023	281,129
February 2022	2022-2024	284,416

Under the market condition for these performance share awards, participants may earn from zero to 200 percent of the apportioned target grant of shares based on the Company's total stockholder return relative to that of the selected peer group. Compensation expense is based on the grant-date fair value as determined by Monte Carlo simulation. The blended volatility term structure ranges are comprised of 50 percent historical volatility and 50 percent implied volatility. Risk-free interest rates were based on U.S. Treasury security rates in effect as of the grant date. Assumptions used for grants applicable to the market condition for certain performance shares issued in 2022, 2021 and 2020 were:

	2022	2021	2020
Weighted average grant-date fair value	**$36.25**	$37.96	$40.75
Blended volatility range	**24.07% - 31.41%**	35.37% - 46.35%	15.30% - 15.97%
Risk-free interest rate range	**.71% - 1.68%**	.02% - .20%	1.45% - 1.62%
Weighted average discounted dividends per share	**$2.93**	$3.16	$2.91

Under the performance conditions for these performance share awards, participants may earn from zero to 200 percent of the apportioned target grant of shares. The performance conditions are based on the Company's compound annual growth rate in earnings from continuing operations before interest, taxes, depreciation, depletion and amortization and the Company's compound annual growth rate in earnings from continuing operations. The weighted average grant-date fair value per share for the performance shares applicable to these performance conditions issued in 2022, 2021 and 2020 was $27.73, $27.35 and $31.63, respectively.

The fair value of the performance shares that vested during the years ended December 31, 2022, 2021 and 2020, was $7.6 million, $13.7 million and $9.7 million, respectively.

A summary of the status of the performance share awards for the year ended December 31, 2022, was as follows:

	Number of Shares	Weighted Average Grant-Date Fair Value
Nonvested at beginning of period	555,047	$ 34.40
Granted	284,416	31.99
Performance shares earned/unearned	(22,750)	31.63
Less:		
Vested	251,168	36.60
Nonvested at end of period	565,545	$ 32.32

Note 14 - Accumulated Other Comprehensive Loss

The Company's accumulated other comprehensive loss is comprised of losses on derivative instruments qualifying as hedges, postretirement liability adjustments and gain (loss) on available-for-sale investments.

The after-tax changes in the components of accumulated other comprehensive loss were as follows:

	Net Unrealized Loss on Derivative Instruments Qualifying as Hedges	Post-retirement Liability Adjustment	Net Unrealized Gain (Loss) on Available-for-sale Investments	Total Accumulated Other Comprehensive Loss
		(In thousands)		
At December 31, 2020	$ (984)	$ (47,207)	$ 113	$ (48,078)
Other comprehensive income (loss) before reclassifications	—	4,876	(252)	4,624
Amounts reclassified from accumulated other comprehensive loss	446	1,870	134	2,450
Net current-period other comprehensive income (loss)	446	6,746	(118)	7,074
At December 31, 2021	(538)	(40,461)	(5)	(41,004)
Other comprehensive income (loss) before reclassifications	—	12,007	(667)	11,340
Amounts reclassified to accumulated other comprehensive loss from a regulatory asset	—	(3,265)	—	(3,265)
Amounts reclassified from accumulated other comprehensive loss	413	1,819	114	2,346
Net current-period other comprehensive income (loss)	413	10,561	(553)	10,421
At December 31, 2022	**$ (125)**	**$ (29,900)**	**$ (558)**	**$ (30,583)**

The following amounts were reclassified out of accumulated other comprehensive loss into net income. The amounts presented in parentheses indicate a decrease to net income on the Consolidated Statements of Income. The reclassifications for the years ended December 31 were as follows:

	2022	2021	Location on Consolidated Statements of Income
	(In thousands)		
Reclassification adjustment for loss on derivative instruments included in net income	**$ (590)**	$ (591)	Interest expense
	177	145	Income taxes
	(413)	(446)	
Amortization of postretirement liability losses included in net periodic benefit credit	**(2,416)**	(2,485)	Other income
	597	615	Income taxes
	(1,819)	(1,870)	
Reclassification adjustment on available-for-sale investments included in net income	**(145)**	(170)	Other income
	31	36	Income taxes
	(114)	(134)	
Total reclassifications	**$ (2,346)**	$ (2,450)	

Note 15 - Income Taxes

The components of income before income taxes from continuing operations for each of the years ended December 31 were as follows:

	2022	2021	2020
		(In thousands)	
United States	**$ 462,059**	$ 466,651	$ 474,856
Foreign	**—**	—	261
Income before income taxes from continuing operations	**$ 462,059**	$ 466,651	$ 475,117

Income tax expense (benefit) from continuing operations for the years ended December 31 was as follows:

	2022	2021	2020
		(In thousands)	
Current:			
Federal	**$ 50,747**	$ 17,121	$ 65,006
State	**20,710**	11,549	21,234
Foreign	**—**	—	151
	71,457	28,670	86,391
Deferred:			
Income taxes:			
Federal	**17,820**	45,885	(3,735)
State	**4,608**	12,610	(625)
Investment tax credit - net	**898**	1,755	2,559
	23,326	60,250	(1,801)
Total income tax expense	**$ 94,783**	$ 88,920	$ 84,590

Components of deferred tax assets and deferred tax liabilities at December 31 were as follows:

	2022	2021
	(In thousands)	
Deferred tax assets:		
Postretirement	**$ 41,298**	$ 45,752
Compensation-related	**35,196**	37,917
Operating lease liabilities	**25,718**	26,710
Asset retirement obligations	**9,687**	8,696
Legal and environmental contingencies	**8,526**	8,603
Customer advances	**7,615**	7,683
Payroll tax deferral	**—**	6,940
Other	**51,472**	39,960
Total deferred tax assets	**179,512**	182,261
Deferred tax liabilities:		
Basis differences on property, plant and equipment	**608,528**	585,095
Postretirement	**47,340**	48,302
Purchased gas adjustment	**33,567**	21,136
Operating lease right-of-use-assets	**25,472**	26,570
Intangible assets	**23,007**	21,074
Other	**60,078**	59,934
Total deferred tax liabilities	**797,992**	762,111
Valuation allowance	**12,823**	12,112
Net deferred income tax liability	**$ 631,303**	$ 591,962

As of December 31, 2022 and 2021, the Company had various state income tax net operating loss carryforwards of $176.0 million and $164.8 million, respectively, and federal and state income tax credit carryforwards, excluding alternative minimum tax credit carryforwards, of $35.7 million and $35.6 million, respectively. The state credits include various regulatory investment tax credits of approximately $35.1 million and $35.0 million at December 31, 2022 and 2021, respectively. The state income tax credit carryforwards are due to expire between 2024 and 2036. Changes in tax regulations or assumptions regarding current and future taxable income could require additional valuation allowances in the future.

The following table reconciles the change in the net deferred income tax liability from December 31, 2021, to December 31, 2022, to deferred income tax expense:

	2022
	(In thousands)
Change in net deferred income tax liability from the preceding table	$ 39,341
Deferred taxes associated with other comprehensive loss	(3,507)
Excess deferred income tax amortization	(9,008)
Other	(3,500)
Deferred income tax expense for the period	$ 23,326

Total income tax expense differs from the amount computed by applying the statutory federal income tax rate to income before taxes. The reasons for this difference were as follows:

Years ended December 31,	2022		2021		2020	
	Amount	%	Amount	%	Amount	%
			(Dollars in thousands)			
Computed tax at federal statutory rate	$ 97,032	21.0	$ 97,997	21.0	$ 99,775	21.0
Increases (reductions) resulting from:						
State income taxes, net of federal income tax	19,126	4.1	19,496	4.2	17,845	3.8
Federal renewable energy credit	(15,343)	(3.3)	(13,914)	(3.0)	(16,009)	(3.4)
Tax compliance and uncertain tax positions	1,080	.2	(477)	(.1)	(3,543)	(.7)
Nonqualified benefit plans	2,827	.6	(1,881)	(.4)	(2,443)	(.5)
Excess deferred income tax amortization	(9,008)	(1.9)	(10,295)	(2.2)	(12,517)	(2.6)
Other	(931)	(.2)	(2,006)	(.4)	1,482	.2
Total income tax expense	$ 94,783	20.5	$ 88,920	19.1	$ 84,590	17.8

The Company and its subsidiaries file income tax returns in the U.S. federal jurisdiction, and various state, local and foreign jurisdictions. The Company is no longer subject to U.S. federal or non-U.S. income tax examinations by tax authorities for years ending prior to 2019. With few exceptions, as of December 31, 2022, the Company is no longer subject to state and local income tax examinations by tax authorities for years ending prior to 2019.

For the years ended December 31, 2022, 2021 and 2020, total reserves for uncertain tax positions were not material. The Company recognizes interest and penalties accrued relative to unrecognized tax benefits in income tax expense.

Note 16 - Cash Flow Information

Cash expenditures for interest and income taxes for the years ended December 31 were as follows:

	2022	2021	2020
		(In thousands)	
Interest, net*	$ 83,118	$ 91,165	$ 88,681
Income taxes paid, net**	$ 26,503	$ 71,079	$ 65,536

* AFUDC - borrowed was $2.2 million, $2.8 million and $2.6 million for the years ended December 31, 2022, 2021 and 2020, respectively.

** Income taxes paid, including discontinued operations, were $26.4 million, $70.9 million and $59.4 million for the years ended December 31, 2022, 2021 and 2020, respectively.

Noncash investing and financing transactions at December 31 were as follows:

	2022	2021	2020
		(In thousands)	
Property, plant and equipment additions in accounts payable	$ 49,602	$ 57,605	$ 26,082
Right-of-use assets obtained in exchange for new operating lease liabilities	$ 50,921	$ 55,987	$ 54,356
Debt assumed in connection with a business combination	$ —	$ 10	$ —
Accrual for holdback payment related to a business combination	$ 70	$ —	$ 2,500
Stock issued in connection with a business combination	$ 7,304	$ —	$ —

Note 17 - Business Segment Data

The Company's reportable segments are those that are based on the Company's method of internal reporting, which generally segregates the strategic business units due to differences in products, services and regulation. The internal reporting of these operating segments is defined based on the reporting and review process used by the Company's chief executive officer. The Company's operations are located within the United States.

The electric segment generates, transmits and distributes electricity in Montana, North Dakota, South Dakota and Wyoming. The natural gas distribution segment distributes natural gas in those states, as well as in Idaho, Minnesota, Oregon and Washington. These operations also supply related value-added services.

The pipeline segment provides natural gas transportation and underground storage services through a regulated pipeline system primarily in the Rocky Mountain and northern Great Plains regions of the United States. This segment also provides non-regulated cathodic protection services.

The construction materials and contracting segment mines, processes and sells construction aggregates (crushed stone and sand and gravel); produces and sells asphalt; and supplies ready-mix concrete. This segment's aggregate reserves provide the foundation for the vertical integration of its contracting services with its construction materials to support its aggregate-based product lines including heavy-civil construction, asphalt paving, concrete construction and site development and grading. Although not common to all locations, the segment also includes the sale of cement, liquid asphalt modification and distribution, various finished concrete products, merchandise and other building materials and related contracting services. This segment operates in the central, southern and western United States, including Alaska and Hawaii.

The construction services segment provides a full spectrum of construction services through its electrical and mechanical and transmission and distribution specialty contracting services across the United States. These specialty contracting services are provided to utilities, manufacturing, transportation, commercial, industrial, institutional, renewable and governmental customers. Its electrical and mechanical contracting services include construction and maintenance of electrical and communication wiring and infrastructure, fire suppression systems, and mechanical piping and services. Its transmission and distribution contracting services include construction and maintenance of overhead and underground electrical, gas and communication infrastructure, as well as manufacturing and distribution of transmission line construction equipment and tools.

The Other category includes the activities of Centennial Capital, which, through its subsidiary InterSource Insurance Company, insures various types of risks as a captive insurer for certain of the Company's subsidiaries. The function of the captive insurer is to fund the self-insured layers of the insured Company's general liability, automobile liability, pollution liability and other coverages. Centennial Capital also owns certain real and personal property. In addition, the Other category includes certain assets, liabilities and tax adjustments of the holding company primarily associated with corporate functions, as well as costs associated with the announced strategic initiatives. Also included are certain general and administrative costs (reflected in operation and maintenance expense) and interest expense, which were previously allocated to the refining business and Fidelity and do not meet the criteria for income (loss) from discontinued operations.

Discontinued operations include the supporting activities of Fidelity other than certain general and administrative costs and interest expense as described above.

The information below follows the same accounting policies as described in Note 2. Information on the Company's segments as of December 31 and for the years then ended was as follows:

	2022	2021	2020
		(In thousands)	
External operating revenues:			
Regulated operations:			
Electric	$ **376,579**	$ 349,039	$ 331,538
Natural gas distribution	**1,273,249**	971,364	847,651
Pipeline	**85,931**	69,940	69,957
	1,735,759	1,390,343	1,249,146
Non-regulated operations:			
Pipeline	**10,636**	12,918	15,389
Construction materials and contracting	**2,533,713**	2,228,306	2,177,585
Construction services	**2,693,756**	2,049,082	2,090,685
Other	**—**	84	(55)
	5,238,105	4,290,390	4,283,604
Total external operating revenues	$ **6,973,864**	$ 5,680,733	$ 5,532,750

	2022	2021	2020
		(In thousands)	
Intersegment operating revenues:			
Regulated operations:			
Electric	**$ 494**	$ 543	$ 491
Natural gas distribution	**555**	576	534
Pipeline	**58,368**	58,989	57,977
	59,417	60,108	59,002
Non-regulated operations:			
Pipeline	**644**	689	554
Construction materials and contracting	**1,016**	624	417
Construction services	**5,494**	2,555	5,038
Other	**17,605**	13,630	11,958
	24,759	17,498	17,967
Total Intersegment operating revenues	**$ 84,176**	$ 77,606	$ 76,969
Depreciation, depletion and amortization:			
Electric	**$ 67,802**	$ 66,750	$ 62,998
Natural gas distribution	**89,466**	86,065	84,580
Pipeline	**26,857**	20,569	21,669
Construction materials and contracting	**117,798**	100,974	89,626
Construction services	**21,468**	20,270	23,523
Other	**4,435**	4,586	2,704
Total depreciation, depletion and amortization	**$ 327,826**	$ 299,214	$ 285,100
Operating income (loss):			
Electric	**$ 79,655**	$ 66,335	$ 63,434
Natural gas distribution	**91,889**	89,173	73,082
Pipeline	**55,466**	48,078	49,436
Construction materials and contracting	**194,295**	191,077	214,498
Construction services	**164,644**	145,754	147,644
Other	**(11,996)**	(6,198)	(3,169)
Total operating income	**$ 573,953**	$ 534,219	$ 544,925
Interest expense:			
Electric	**$ 28,526**	$ 26,712	$ 26,699
Natural gas distribution	**42,126**	37,265	36,798
Pipeline	**11,318**	7,010	7,622
Construction materials and contracting	**30,121**	19,218	20,577
Construction services	**6,354**	3,540	4,095
Other	**1,465**	342	883
Intersegment eliminations	**(637)**	(103)	(155)
Total interest expense	**$ 119,273**	$ 93,984	$ 96,519
Income tax expense (benefit):			
Electric	**$ (5,420)**	$ (7,626)	$ (11,636)
Natural gas distribution	**7,805**	8,366	5,746
Pipeline	**10,212**	9,594	7,650
Construction materials and contracting	**42,601**	43,459	47,431
Construction services	**40,788**	35,426	35,797
Other	**(1,203)**	(299)	(398)
Total income tax expense	**$ 94,783**	$ 88,920	$ 84,590

	2022	2021	2020
		(In thousands)	
Net income (loss):			
Regulated operations:			
Electric	**$ 57,077**	$ 51,906	$ 55,601
Natural gas distribution	**45,171**	51,596	44,049
Pipeline	**35,357**	39,583	35,453
	137,605	143,085	135,103
Non-regulated operations:			
Pipeline	**(69)**	1,313	1,559
Construction materials and contracting	**116,220**	129,755	147,325
Construction services	**124,781**	109,402	109,721
Other	**(11,261)**	(5,824)	(3,181)
	229,671	234,646	255,424
Income from continuing operations	**367,276**	377,731	390,527
Discontinued operations, net of tax	**213**	400	(322)
Net income	**$ 367,489**	$ 378,131	$ 390,205
Capital expenditures:			
Electric	**$ 133,970**	$ 82,427	$ 114,676
Natural gas distribution	**240,064**	170,411	193,048
Pipeline	**61,923**	234,803	62,224
Construction materials and contracting	**181,917**	417,524	191,635
Construction services	**36,413**	29,140	83,651
Other	**2,272**	1,501	3,045
Total capital expenditures (a)	**$ 656,559**	$ 935,806	$ 648,279
Assets:			
Electric (b)	**$ 1,856,258**	$ 1,810,695	$ 2,123,693
Natural gas distribution (b)	**3,214,452**	2,929,519	2,302,770
Pipeline	**961,893**	913,945	703,377
Construction materials and contracting	**2,268,970**	2,161,653	1,798,493
Construction services	**1,126,323**	845,262	818,662
Other (c)	**232,885**	249,361	306,377
Total assets	**$ 9,660,781**	$ 8,910,435	$ 8,053,372
Property, plant and equipment:			
Electric (b)	**$ 2,276,613**	$ 2,295,646	$ 2,323,403
Natural gas distribution (b)	**3,208,060**	3,015,164	2,868,853
Pipeline	**1,108,141**	1,051,868	821,697
Construction materials and contracting	**2,489,408**	2,347,696	2,028,476
Construction services	**245,111**	225,758	220,796
Other	**36,705**	36,717	37,545
Less accumulated depreciation, depletion and amortization	**3,272,493**	3,216,461	3,133,831
Net property, plant and equipment	**$ 6,091,545**	$ 5,756,388	$ 5,166,939

(a) Capital expenditures for 2022, 2021 and 2020 include noncash transactions such as capital expenditure-related accounts payable, the issuance of the Company's equity securities in connection with an acquisition, AFUDC and accrual of holdback payments in connection with acquisitions totaling $1.7 million, $38.7 million and $(15.7) million, respectively.

(b) Includes allocations of common utility property.

(c) Includes assets not directly assignable to a business (i.e. cash and cash equivalents, certain accounts receivable, certain investments and other miscellaneous current and deferred assets).

A reconciliation of reportable segment operating revenues and assets to consolidated operating revenues and assets is as follows:

	2022	2021	2020
		(In thousands)	
Operating revenues reconciliation:			
Total reportable segment operating revenues	**$ 7,040,435**	$ 5,744,625	$ 5,597,816
Other revenue	**17,605**	13,714	11,903
Elimination of intersegment operating revenues	**(84,176)**	(77,606)	(76,969)
Total consolidated operating revenues	**$ 6,973,864**	$ 5,680,733	$ 5,532,750
Asset reconciliation:			
Total reportable segment assets	**$ 9,491,679**	$ 8,717,563	$ 7,816,848
Other assets	**1,353,614**	1,184,956	947,740
Elimination of intersegment receivables	**(1,184,512)**	(992,084)	(711,216)
Total consolidated assets	**$ 9,660,781**	$ 8,910,435	$ 8,053,372

Note 18 - Employee Benefit Plans

Pension and other postretirement benefit plans

The Company has noncontributory qualified defined benefit pension plans and other postretirement benefit plans for certain eligible employees. The Company uses a measurement date of December 31 for all of its pension and postretirement benefit plans.

Prior to 2013, defined benefit pension plan benefits and accruals for all nonunion and certain union plans were frozen and on June 30, 2015, the remaining union plan was frozen. These employees were eligible to receive additional defined contribution plan benefits.

Effective January 1, 2010, eligibility to receive retiree medical benefits was modified at certain of the Company's businesses. Employees who had attained age 55 with 10 years of continuous service by December 31, 2010, were provided the option to choose between a pre-65 comprehensive medical plan coupled with a Medicare supplement or a specified company funded Retiree Reimbursement Account, regardless of when they retire. All other eligible employees must meet the new eligibility criteria of age 60 and 10 years of continuous service at the time they retire to be eligible for a specified company funded Retiree Reimbursement Account. Employees hired after December 31, 2009, will not be eligible for retiree medical benefits at certain of the Company's businesses.

In 2012, the Company modified health care coverage for certain retirees. Effective January 1, 2013, post-65 coverage was replaced by a fixed-dollar subsidy for retirees and spouses to be used to purchase individual insurance through a healthcare exchange.

Changes in benefit obligation and plan assets and amounts recognized in the Consolidated Balance Sheets at December 31 were as follows:

	Pension Benefits		Other Postretirement Benefits	
	2022	2021	**2022**	2021
Change in benefit obligation:		(In thousands)		
Benefit obligation at beginning of year	**$ 411,497**	$ 437,360	**$ 73,460**	$ 86,155
Service cost	**—**	—	**1,416**	1,600
Interest cost	**10,522**	9,819	**1,896**	1,862
Plan participants' contributions	**—**	—	**569**	641
Actuarial gain	**(85,303)**	(12,140)	**(18,401)**	(12,802)
Benefits paid	**(24,672)**	(23,542)	**(4,009)**	(3,996)
Benefit obligation at end of year	**312,044**	411,497	**54,931**	73,460
Change in net plan assets:				
Fair value of plan assets at beginning of year	**373,109**	383,834	**100,158**	101,639
Actual return on plan assets	**(77,975)**	12,817	**(20,893)**	1,398
Employer contribution	**—**	—	**501**	476
Plan participants' contributions	**—**	—	**569**	641
Benefits paid	**(24,672)**	(23,542)	**(4,009)**	(3,996)
Fair value of net plan assets at end of year	**270,462**	373,109	**76,326**	100,158
Funded status - (under) over	**$ (41,582)**	$ (38,388)	**$ 21,395**	$ 26,698
Amounts recognized in the Consolidated Balance Sheets at December 31:				
Noncurrent assets - other	**$ —**	$ —	**$ 36,325**	$ 45,863
Other accrued liabilities	**—**	—	**1,044**	544
Noncurrent liabilities - other	**41,582**	38,388	**13,886**	18,621
Benefit obligation (liabilities) assets - net amount recognized	**$ (41,582)**	$ (38,388)	**$ 21,395**	$ 26,698
Amounts recognized in accumulated other comprehensive loss:				
Actuarial loss (gain)	**$ 32,378**	$ 25,976	**$ (2,923)**	$ 2,367
Prior service credit	**—**	—	**(289)**	(290)
Total	**$ 32,378**	$ 25,976	**$ (3,212)**	$ 2,077
Amounts recognized in regulatory assets or liabilities:				
Actuarial loss (gain)	**$ 141,207**	$ 142,166	**$ (1,439)**	$ (14,727)
Prior service credit	**—**	—	**(3,796)**	(5,193)
Total	**$ 141,207**	$ 142,166	**$ (5,235)**	$ (19,920)

Employer contributions and benefits paid in the preceding table include only those amounts contributed directly to, or paid directly from, plan assets. Amounts related to regulated operations are recorded as regulatory assets or liabilities and are expected to be reflected in rates charged to customers over time. For more information on regulatory assets and liabilities, see Note 6.

In 2022 and 2021, the actuarial gain recognized in the benefit obligation was primarily the result of an increase in the discount rate. For more information on the discount rates, see the table below. Unrecognized pension actuarial gains and losses in excess of 10 percent of the greater of the projected benefit obligation or the market-related value of assets are amortized over the average life expectancy of plan participants for frozen plans. The market-related value of assets is determined using a five-year average of assets.

The pension plans all have accumulated benefit obligations in excess of plan assets. The projected benefit obligation, accumulated benefit obligation and fair value of plan assets for these plans at December 31 were as follows:

	2022	2021
	(In thousands)	
Projected benefit obligation	**$ 312,044**	$ 411,497
Accumulated benefit obligation	**$ 312,044**	$ 411,497
Fair value of plan assets	**$ 270,462**	$ 373,109

The components of net periodic benefit cost (credit), other than the service cost component, are included in other income on the Consolidated Statements of Income. Prior service credit is amortized on a straight-line basis over the average remaining service period of active participants. These components related to the Company's pension and other postretirement benefit plans for the years ended December 31 were as follows:

	Pension Benefits			Other Postretirement Benefits		
	2022	2021	2020	**2022**	2021	2020
Components of net periodic benefit credit:			(In thousands)			
Service cost	**$ —**	$ —	$ —	**$ 1,416**	$ 1,600	$ 1,532
Interest cost	**10,522**	9,819	12,093	**1,896**	1,862	2,437
Expected return on assets	**(19,455)**	(19,576)	(19,949)	**(5,288)**	(5,098)	(5,019)
Amortization of prior service credit	**—**	—	—	**(1,398)**	(1,398)	(1,398)
Recognized net actuarial loss (gain)	**6,683**	8,017	7,172	**(219)**	24	287
Net periodic benefit credit, including amount capitalized	**(2,250)**	(1,740)	(684)	**(3,593)**	(3,010)	(2,161)
Less amount capitalized	**—**	—	—	**175**	150	156
Net periodic benefit cost credit	**(2,250)**	(1,740)	(684)	**(3,768)**	(3,160)	(2,317)
Other changes in plan assets and benefit obligations recognized in accumulated comprehensive loss:						
Net (gain) loss	**2,369**	(265)	934	**(4,141)**	(2,811)	(259)
Amortization of actuarial loss	**(1,310)**	(1,286)	(1,155)	**(281)**	(135)	(306)
Amortization of prior service credit	**—**	—	—	**125**	100	101
Reclassification of postretirement liability adjustment from regulatory asset	**5,343**	—	—	**(992)**	—	—
Total recognized in accumulated other comprehensive loss	**6,402**	(1,551)	(221)	**(5,289)**	(2,846)	(464)
Other changes in plan assets and benefit obligations recognized in regulatory assets or liabilities:						
Net (gain) loss	**9,757**	(5,116)	4,546	**11,920**	(6,292)	(3,793)
Amortization of actuarial gain (loss)	**(5,373)**	(6,731)	(6,017)	**500**	110	19
Amortization of prior service credit	**—**	—	—	**1,273**	1,298	1,297
Reclassification of postretirement liability adjustment from regulatory asset	**(5,343)**	—	—	**992**	—	—
Total recognized in regulatory assets or liabilities	**(959)**	(11,847)	(1,471)	**14,685**	(4,884)	(2,477)
Total recognized in net periodic benefit credit, accumulated other comprehensive loss and regulatory assets or liabilities	**$ 3,193**	$ (15,138)	$ (2,376)	**$ 5,628**	$ (10,890)	$ (5,258)

Weighted average assumptions used to determine benefit obligations at December 31 were as follows:

	Pension Benefits		Other Postretirement Benefits	
	2022	2021	**2022**	2021
Discount rate	**5.06 %**	2.64 %	**5.07 %**	2.66 %
Expected return on plan assets	**6.50 %**	6.00 %	**6.00 %**	5.50 %
Rate of compensation increase	**N/A**	N/A	**3.00 %**	3.00 %

Weighted average assumptions used to determine net periodic benefit cost (credit) for the years ended December 31 were as follows:

	Pension Benefits		Other Postretirement Benefits	
	2022	2021	**2022**	2021
Discount rate	**2.64 %**	2.30 %	**2.66 %**	2.30 %
Expected return on plan assets	**6.00 %**	6.00 %	**5.50 %**	5.50 %
Rate of compensation increase	**N/A**	N/A	**3.00 %**	3.00 %

The expected rate of return on pension plan assets is based on a targeted asset allocation range determined by the funded ratio of the plan. As of December 31, 2022, the expected rate of return on pension plan assets is based on the targeted asset allocation range of 40 percent to 50 percent equity securities and 50 percent to 60 percent fixed-income securities and the expected rate of return from these asset categories. The expected rate of return on other postretirement plan assets is based on the targeted asset allocation range of 10 percent to 20 percent equity securities and 80 percent to 90 percent fixed-income securities and the expected rate of return from these asset categories. The expected return on plan assets for other postretirement benefits reflects insurance-related investment costs.

Health care rate assumptions for the Company's other postretirement benefit plans as of December 31 were as follows:

	2022	2021
Health care trend rate assumed for next year	**7.5 %**	7.0 %
Health care cost trend rate - ultimate	**4.5 %**	4.5 %
Year in which ultimate trend rate achieved	**2033**	2031

The Company's other postretirement benefit plans include health care and life insurance benefits for certain retirees. The plans underlying these benefits may require contributions by the retiree depending on such retiree's age and years of service at retirement or the date of retirement. The Company contributes a flat dollar amount to the monthly premiums which is updated annually on January 1.

The Company does not expect to contribute to its defined benefit pension plans in 2023 due to an additional $20.0 million contributed to the plans in 2019 creating prefunding credits to be used in future years. The Company expects to contribute approximately $595,000 to its postretirement benefit plans in 2023.

The following benefit payments, which reflect future service, as appropriate, and expected Medicare Part D subsidies at December 31, 2022, are as follows:

Years	Pension Benefits	Other Postretirement Benefits	Expected Medicare Part D Subsidy
		(In thousands)	
2023	$ 24,936	$ 4,275	$ 62
2024	24,882	4,371	53
2025	24,749	4,456	46
2026	24,605	4,509	39
2027	24,387	4,523	31
2028-2032	114,850	16,917	93

Outside investment managers manage the Company's pension and postretirement assets. The Company's investment policy with respect to pension and other postretirement assets is to make investments solely in the interest of the participants and beneficiaries of the plans and for the exclusive purpose of providing benefits accrued and defraying the reasonable expenses of administration. The Company strives to maintain investment diversification to assist in minimizing the risk of large losses. The Company's policy guidelines allow for investment of funds in cash equivalents, fixed-income securities and equity securities. The guidelines prohibit investment in commodities and futures contracts, equity private placement, employer securities, leveraged or derivative securities, options, direct real estate investments, precious metals, venture capital and limited partnerships. The guidelines also prohibit short selling and margin transactions. The Company's practice is to periodically review and rebalance asset categories based on its targeted asset allocation percentage policy.

Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability (an exit price) in an orderly transaction between market participants at the measurement date. The fair value ASC establishes a hierarchy for grouping assets and liabilities, based on the significance of inputs. The estimated fair values of the Company's pension plans' assets are determined using the market approach.

The carrying value of the pension plans' Level 2 cash equivalents approximates fair value and is determined using observable inputs in active markets or the net asset value of shares held at year end, which is determined using other observable inputs including pricing from outside sources.

The estimated fair value of the pension plans' Level 1 and Level 2 equity securities are based on the closing price reported on the active market on which the individual securities are traded or other known sources including pricing from outside sources. The estimated fair value of the pension plans' Level 1 and Level 2 collective and mutual funds are based on the net asset value of shares held at year end, based on either published market quotations on active markets or other known sources including pricing from outside sources. The estimated fair value of the pension plans' Level 2 corporate and municipal bonds is determined using other observable inputs, including benchmark yields, reported trades, broker/dealer quotes, bids, offers, future cash flows and other reference data. The estimated fair value of the pension plans' Level 1 U.S. Government securities are valued based on quoted prices on an active market. The estimated fair value of the pension plans' Level 2 U.S. Government securities are valued mainly using other observable inputs, including benchmark yields, reported trades, broker/dealer quotes, bids, offers, to be announced prices, future cash flows and other reference data. The estimated fair value of the pension plans' Level 2 pooled separate accounts are determined using observable inputs in active markets or the net asset value of shares held at year end, or other observable inputs. Some of these securities are valued using pricing from outside sources.

All investments measured at net asset value in the tables that follow are invested in commingled funds, separate accounts or common collective trusts which do not have publicly quoted prices. The fair value of the commingled funds, separate accounts and common collective trusts are determined based on the net asset value of the underlying investments. The fair value of the underlying investments held by the commingled funds, separate accounts and common collective trusts is generally based on quoted prices in active markets.

Though the Company believes the methods used to estimate fair value are consistent with those used by other market participants, the use of other methods or assumptions could result in a different estimate of fair value.

The fair value of the Company's pension plans' assets (excluding cash) by class were as follows:

	Fair Value Measurements at December 31, 2022, Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at December 31, 2022
		(In thousands)		
Assets:				
Cash equivalents	$ —	$ 8,170	$ —	$ 8,170
Equity securities:				
U.S. companies	7,388	—	—	7,388
International companies	—	467	—	467
Collective and mutual funds (a)	121,072	33,371	—	154,443
Corporate bonds	—	81,363	—	81,363
Municipal bonds	—	5,904	—	5,904
U.S. Government securities	3,044	880	—	3,924
Pooled separate accounts (b)	—	3,241	—	3,241
Investments measured at net asset value (c)	—	—	—	5,562
Total assets measured at fair value	$ 131,504	$ 133,396	$ —	$ 270,462

(a) Collective and mutual funds invest approximately 29 percent in corporate bonds, 24 percent in common stock of large-cap U.S. companies, 16 percent in common stock of international companies, 7 percent cash and cash equivalents, 7 percent in U.S. Government securities and 17 percent in other investments.
(b) Pooled separate accounts are invested 100 percent in cash and cash equivalents.
(c) In accordance with ASC 820 - *Fair Value Measurements,* certain investments that were measured at net asset value per share (or its equivalent) have not been classified in the fair value hierarchy. The fair value amounts presented in this table are intended to permit reconciliation of the fair value hierarchy to the line items presented in the Consolidated Balance Sheets.

	Fair Value Measurements at December 31, 2021, Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at December 31, 2021
		(In thousands)		
Assets:				
Cash equivalents	$ —	$ 4,637	$ —	$ 4,637
Equity securities:				
U.S. companies	7,483	—	—	7,483
International companies	—	1,279	—	1,279
Collective and mutual funds (a)	167,093	41,383	—	208,476
Corporate bonds	—	125,167	—	125,167
Municipal bonds	—	7,507	—	7,507
U.S. Government securities	7,113	1,902	—	9,015
Pooled separate accounts (b)	—	3,088	—	3,088
Investments measured at net asset value (c)	—	—	—	6,457
Total assets measured at fair value	$ 181,689	$ 184,963	$ —	$ 373,109

(a) Collective and mutual funds invest approximately 37 percent in corporate bonds, 19 percent in common stock of international companies, 16 percent in common stock of large-cap U.S. companies, 9 percent in U.S. Government securities and 19 percent in other investments.
(b) Pooled separate accounts are invested 100 percent in cash and cash equivalents.
(c) In accordance with ASC 820 - *Fair Value Measurements,* certain investments that were measured at net asset value per share (or its equivalent) have not been classified in the fair value hierarchy. The fair value amounts presented in this table are intended to permit reconciliation of the fair value hierarchy to the line items presented in the Consolidated Balance Sheets.

The estimated fair values of the Company's other postretirement benefit plans' assets are determined using the market approach.

The estimated fair value of the other postretirement benefit plans' Level 2 cash equivalents is valued at the net asset value of shares held at year end, based on published market quotations on active markets, or using other known sources including pricing from outside sources. The estimated fair value of the other postretirement benefit plans' Level 1 and Level 2 equity securities is based on the closing price reported on the active market on which the individual securities are traded or other known sources including pricing from outside sources. The estimated fair value of the other postretirement benefit plans' Level 2 insurance contract is based on contractual cash surrender values that are determined primarily by investments in managed separate accounts of the insurer. These amounts approximate fair value. The managed separate accounts are valued based on other observable inputs or corroborated market data.

Though the Company believes the methods used to estimate fair value are consistent with those used by other market participants, the use of other methods or assumptions could result in a different estimate of fair value.

The fair value of the Company's other postretirement benefit plans' assets (excluding cash) by asset class were as follows:

	Fair Value Measurements at December 31, 2022, Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at December 31, 2022
		(In thousands)		
Assets:				
Cash equivalents	$ —	$ 4,196	$ —	$ 4,196
Equity securities:				
U.S. companies	2,572	—	—	2,572
Collective and mutual funds (a)	5	5	—	10
Insurance contract (b)	—	69,548	—	69,548
Total assets measured at fair value	$ 2,577	$ 73,749	$ —	$ 76,326

(a) Collective and mutual funds invest approximately 29 percent in corporate bonds, 24 percent in common stock of large-cap U.S. companies,16 percent in common stock of international companies, 7 percent in cash and cash equivalents,7 percent in U.S. Government securities and 17 percent in other investments.
(b) The insurance contract invests approximately 69 percent in corporate bonds, 13 percent in U.S. Government securities, 14 percent in common stock of large-cap U.S. companies and 4 percent in common stock of small-cap U.S. companies.

	Fair Value Measurements at December 31, 2021, Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at December 31, 2021
		(In thousands)		
Assets:				
Cash equivalents	$ —	$ 4,281	$ —	$ 4,281
Equity securities:				
U.S. companies	2,332	—	—	2,332
International companies	—	1	—	1
Collective and mutual funds (a)	4	90	—	94
Insurance contract (b)	—	93,447	—	93,447
Investments measured at net asset value (c)	—	—	—	3
Total assets measured at fair value	$ 2,336	$ 97,819	$ —	$ 100,158

(a) Collective and mutual funds invest approximately 37 percent in corporate bonds, 19 percent in common stock of international companies, 16 percent in common stock of large-cap U.S. companies, 9 percent in U.S. Government securities and 19 percent in other investments.
(b) The insurance contract invests approximately 58 percent in corporate bonds, 13 percent in common stock of large-cap U.S. companies, 13 percent in U.S. Government securities, 5 percent in common stock of small-cap U.S. companies and 11 percent in other investments.
(c) In accordance with ASC 820 - *Fair Value Measurements,* certain investments that were measured at net asset value per share (or its equivalent) have not been classified in the fair value hierarchy. The fair value amounts presented in this table are intended to permit reconciliation of the fair value hierarchy to the line items presented in the Consolidated Balance Sheets.

Nonqualified benefit plans

In addition to the qualified defined benefit pension plans reflected in the table at the beginning of this note, the Company also has unfunded, nonqualified defined benefit plans for executive officers and certain key management employees that generally provide for defined benefit payments at age 65 following the employee's retirement or, upon death, to their beneficiaries for a 15-year period. In February 2016, the Company froze the unfunded, nonqualified defined benefit plans to new participants and eliminated benefit increases. Vesting for participants not fully vested was retained.

The projected benefit obligation and accumulated benefit obligation for these plans at December 31 were as follows:

	2022	2021
	(In thousands)	
Projected benefit obligation	**$ 74,730**	$ 92,918
Accumulated benefit obligation	**$ 74,730**	$ 92,918

The components of net periodic benefit cost are included in other income on the Consolidated Statements of Income. These components related to the Company's nonqualified defined benefit plans for the years ended December 31 were as follows:

	2022	2021	2020
		(In thousands)	
Components of net periodic benefit cost:			
Service cost	**$ —**	$ —	$ 58
Interest cost	**2,142**	1,912	2,606
Recognized net actuarial loss	**950**	1,164	1,192
Net periodic benefit cost	**$ 3,092**	$ 3,076	$ 3,856

Weighted average assumptions used at December 31 were as follows:

	2022	2021
Benefit obligation discount rate	**4.97 %**	2.39 %
Benefit obligation rate of compensation increase	**N/A**	N/A
Net periodic benefit cost discount rate	**2.39 %**	1.97 %
Net periodic benefit cost rate of compensation increase	**N/A**	N/A

The amount of future benefit payments for the unfunded, nonqualified defined benefit plans at December 31, 2022, are expected to aggregate as follows:

	2023	2024	2025	2026	2027	2028-2032
			(In thousands)			
Nonqualified benefits	$ 6,651	$ 7,183	$ 7,430	$ 7,537	$ 7,420	$ 29,930

In 2012, the Company established a nonqualified defined contribution plan for certain key management employees. In 2020, the plan was frozen to new participants and no new Company contributions will be made to the plan after December 31, 2020. Vesting for participants not fully vested was retained. A new nonqualified defined contribution plan was adopted in 2020, effective January 1, 2021, to replace the plan originally established in 2012 with similar provisions. Expenses incurred under these plans for 2022, 2021 and 2020 were $3.3 million, $2.4 million and $1.8 million, respectively.

The amount of investments that the Company anticipates using to satisfy obligations under these plans at December 31 was as follows:

	2022	2021
	(In thousands)	
Investments		
Insurance contracts*	**$ 98,041**	$ 109,603
Life insurance**	**38,448**	38,356
Other	**7,361**	10,190
Total investments	**$ 143,850**	$ 158,149

* For more information on the insurance contracts, see Note 8.

** Investments of life insurance are carried on plan participants (payable upon the employee's death).

Defined contribution plans

The Company sponsors a defined contribution plan for eligible employees and the costs incurred under this plan were $46.4 million in 2022, $45.4 million in 2021 and $50.1 million in 2020.

Multiemployer plans

The Company contributes to a number of MEPPs under the terms of collective-bargaining agreements that cover its union-represented employees. The risks of participating in these multiemployer plans are different from single-employer plans in the following aspects:

- Assets contributed to the MEPP by one employer may be used to provide benefits to employees of other participating employers
- If a participating employer stops contributing to the plan, the unfunded obligations of the plan may be borne by the remaining participating employers
- If the Company chooses to stop participating in some of its MEPPs, the Company may be required to pay those plans an amount based on the underfunded status of the plan, referred to as a withdrawal liability

The Company's participation in these plans is outlined in the following table. Unless otherwise noted, the most recent Pension Protection Act zone status available in 2022 and 2021 is for the plan's year-end at December 31, 2021, and December 31, 2020, respectively. The zone status is based on information that the Company received from the plan and is certified by the plan's actuary. Among other factors, plans in the red zone are generally less than 65 percent funded, plans in the yellow zone are between 65 percent and 80 percent funded, and plans in the green zone are at least 80 percent funded.

		Pension Protection Act Zone Status		FIP/RP Status	Contributions				Expiration Date
Pension Fund	EIN/Pension Plan Number	**2022**	2021	Pending/ Implemented	**2022**	2021	2020	Surcharge Imposed	of Collective Bargaining Agreement
					(In thousands)				
Edison Pension Plan	936061681-001	**Green**	Green	No	**$ 18,750**	$ 18,331	$ 16,121	No	12/31/2023
IBEW Local 212 Pension Trust	316127280-001	**Green as of 4/30/2021**	Green as of 4/30/2021	No	**1,622**	1,733	1,521	No	6/1/2025
IBEW Local 357 Pension Plan A	886023284-001	**Green**	Green	No	**12,876**	6,485	9,913	No	5/31/2024
IBEW Local 82 Pension Plan	316127268-001	**Green as of 6/30/2022**	Green as of 6/30/2021	No	**1,854**	1,353	1,373	No	12/3/2023
IBEW Local 648 Pension Plan	316134845-001	**Yellow as of 2/28/2022**	Yellow as of 02/28/2021	Implemented	**915**	706	526	No	9/1/2024
IBEW Local 683 Pension Fund Pension Plan	341442087-001	**Green**	Green	No	**3,362**	1,238	1,240	No	5/26/2024
Idaho Plumbers and Pipefitters Pension Plan	826010346-001	**Green as of 5/31/2022**	Green as of 5/31/2021	No	**1,613**	1,528	1,370	No	3/31/2023
National Electrical Benefit Fund	530181657-001	**Green**	Green	No	**18,060**	14,361	14,484	No	5/31/2022-5/31/2027 *
Pension and Retirement Plan of Plumbers and Pipefitters Local 525	886003864-001	**Green as of 6/30/2022**	Green as of 6/30/2021	No	**6,304**	4,345	6,266	No	9/30/2024
Pension Trust Fund for Operating Engineers	946090764-001	**Yellow**	Yellow	Implemented	**2,484**	2,495	2,680	No	3/31/2023-6/15/2026
Sheet Metal Workers Pension Plan of Southern CA, AZ, and NV	956052257-001	**Green**	Yellow	Implemented	**3,400**	2,615	3,255	No	6/30/2024
Western Conference of Teamsters Pension Plan	916145047-001	**Green**	Green	No	**3,127**	3,006	3,025	No	12/31/2023-12/31/2025
Other funds					**26,909**	24,192	23,670		
Total contributions					**$ 101,276**	$ 82,388	$ 85,444		

* Plan includes contributions required by collective bargaining agreements which have expired but contain provisions automatically renewing their terms in the absence of a subsequent negotiated agreement.

The Company was listed in the plans' Forms 5500 as providing more than 5 percent of the total contributions for the following plans and plan years:

Pension Fund	Year Contributions to Plan Exceeded More Than 5 Percent of Total Contributions (as of December 31 of the Plan's Year-End)
Edison Pension Plan	2021 and 2020
IBEW Local 82 Pension Plan	2021 and 2020
IBEW Local 124 Pension Trust Fund	2021 and 2020
IBEW Local 212 Pension Trust Fund	2021 and 2020
IBEW Local 357 Pension Plan A	2021 and 2020
IBEW Local 648 Pension Plan	2021 and 2020
IBEW Local 683 Pension Fund Pension Plan	2021 and 2020
IBEW Local Union No 226 Open End Pension Fund	2020
Idaho Plumbers and Pipefitters Pension Plan	2021 and 2020
International Union of Operating Engineers Local 701 Pension Trust Fund	2021 and 2020
Minnesota Teamsters Construction Division Pension Fund	2021 and 2020
Pension and Retirement Plan of Plumbers and Pipefitters Local 525	2021 and 2020
Southwest Marine Pension Trust	2021 and 2020

The Company also contributes to a number of multiemployer other postretirement plans under the terms of collective-bargaining agreements that cover its union-represented employees. These plans provide benefits such as health insurance, disability insurance and life insurance to retired union employees. Many of the multiemployer other postretirement plans are combined with active multiemployer health and welfare plans. The Company's total contributions to its multiemployer other postretirement plans, which also includes contributions to active multiemployer health and welfare plans, were $81.0 million, $66.1 million and $63.8 million for the years ended December 31, 2022, 2021 and 2020, respectively.

Amounts contributed in 2022, 2021 and 2020 to defined contribution multiemployer plans were $67.9 million, $54.8 million and $54.2 million, respectively.

Note 19 - Jointly Owned Facilities

The consolidated financial statements include the Company's ownership interests in three coal-fired electric generating facilities (Big Stone Station, Coyote Station and Wygen III) and one major transmission line (BSSE). Each owner of the jointly owned facilities is responsible for financing its investment. The Company's share of the jointly owned facilities operating expenses was reflected in the appropriate categories of operating expenses (electric fuel and purchased power; operation and maintenance; and taxes, other than income) in the Consolidated Statements of Income.

At December 31, the Company's share of the cost of utility plant in service, construction work in progress and related accumulated depreciation for the jointly owned facilities was as follows:

	Ownership Percentage	**2022**	2021
		(In thousands)	
Big Stone Station:	22.7 %		
Utility plant in service		**$ 157,699**	$ 157,259
Construction work in progress		**231**	571
Less accumulated depreciation		**48,590**	47,293
		$ 109,340	$ 110,537
BSSE:	50.0 %		
Utility plant in service		**$ 107,260**	$ 107,424
Construction work in progress		**—**	—
Less accumulated depreciation		**6,182**	4,506
		$ 101,078	$ 102,918
Coyote Station:	25.0 %		
Utility plant in service		**$ 158,274**	$ 157,764
Construction work in progress		**1,807**	784
Less accumulated depreciation		**111,203**	109,202
		$ 48,878	$ 49,346
Wygen III:	25.0 %		
Utility plant in service		**$ 66,238**	$ 66,357
Construction work in progress		**273**	108
Less accumulated depreciation		**12,477**	11,383
		$ 54,034	$ 55,082

Note 20 - Regulatory Matters

The Company regularly reviews the need for electric and natural gas rate changes in each of the jurisdictions in which service is provided. The Company files for rate adjustments to seek recovery of operating costs and capital investments, as well as reasonable returns as allowed by regulators. Certain regulatory proceedings and cases may also contain recurring mechanisms that can have an annual true-up. Examples of these recurring mechanisms include: infrastructure riders, transmission trackers, renewable resource cost adjustment riders, as well as weather normalization and decoupling mechanisms. The following paragraphs summarize the Company's significant open regulatory proceedings and cases by jurisdiction. The Company is unable to predict the ultimate outcome of these matters, the timing of final decisions of the various regulators and courts, or the effect on the Company's results of operations, financial position or cash flows.

IPUC

Intermountain filed a request with the IPUC for a natural gas general rate increase on December 1, 2022. The request is for an increase of $11.3 million annually or 3.2 percent above current rates. The requested increase is primarily to recover investments made since the last rate case in 2016 and the depreciation, operation and maintenance expenses and taxes associated with the increased investments. The IPUC has up to seven months to issue a decision on the request, which is currently pending.

Intermountain defers the difference between the actual cost of gas spent to serve customers and the amount approved to be recovered from customers and annually prepares a true-up pursuant to the purchased gas adjustment tariff. On December 27, 2022, Intermountain filed an application with the IPUC for an out-of-cycle cost of gas adjustment requesting an increase in rates of approximately $56.5 million annually or approximately 17.1 percent above current rates. The primary reason for the requested increase was to mitigate the under-collection balance due to the significant increase in the commodity price for natural gas. On January 30, 2023, the request was approved with rates effective February 1, 2023.

MNPUC

Great Plains defers the difference between the actual cost of gas spent to serve customers and that recovered from customers on a monthly basis. Annually, Great Plains prepares a true-up pursuant to the purchased gas adjustment tariff. On August 30, 2021, the MNPUC issued an order to allow Great Plains recovery of an out-of-cycle cost of gas adjustment of $8.8 million over a period of 27 months. The order was effective September 1, 2021, and was subject to a prudence review by the MNPUC. The requested increase was for the February 2021 extreme cold weather, primarily in the central United States, and market conditions surrounding the natural gas commodity market. On October 19, 2022, the MNPUC issued a final order disallowing $845,000 of the gas costs. These costs, which were deferred as a regulatory asset in natural gas costs recoverable through rate adjustments, were then recorded to expense as they were no longer recoverable from customers. On November 8, 2022, Great Plains filed a request for reconsideration, which was denied by the MNPUC on January 6, 2023.

On June 1, 2022, Great Plains filed an application with the MNPUC for a decrease in its depreciation and amortization rates of approximately $1.2 million annually or a decrease from a combined rate of 4.5 percent to 2.8 percent. Great Plains requested the rates be retroactive to January 1, 2022. On November 8, 2022, the MNPUC approved a decrease of $1.0 million annually with rates retroactive to January 1, 2022.

MTPSC

On November 4, 2022, Montana-Dakota filed an application with the MTPSC for an electric general rate increase of approximately $10.5 million annually or 15.2 percent above current rates. The requested increase is primarily to recover investments made since the last rate case, including the Heskett 4 gas turbine, increases in operation and maintenance expenses, and increases in property taxes. On January 24, 2023, the MTPSC approved Montana-Dakota's request for an interim increase of approximately $1.7 million or 2.7 percent above current rates, subject to refund, effective February 1, 2023. The MTPSC has 9 months to render a final decision on the rate case. The matter is pending before the MTPSC with a hearing scheduled for June 20, 2023.

NDPSC

On May 16, 2022, Montana-Dakota filed an application with the NDPSC for an electric general rate increase of approximately $25.4 million annually or 12.3 percent above current rates. The requested increase is primarily to recover investments in production, transmission and distribution facilities and the associated depreciation, operation and maintenance expenses and taxes associated with the increased investment. On July 14, 2022, the NDPSC approved an interim rate increase of approximately $10.9 million annually or 5.3 percent above current rates, subject to refund, for service rendered on and after July 15, 2022. The lower interim rate increase is largely due to excluding the recovery of Heskett Unit 4, which is expected to be in service in the summer of 2023. The matter is pending before the NDPSC with a hearing scheduled for May 1, 2023.

Montana-Dakota has a renewable resource cost adjustment rate tariff that allows for annual adjustments for recent projected capital costs and related expenses for projects determined to be recoverable under the tariff. On November 1, 2022, Montana-Dakota filed an annual update to its renewable resource cost adjustment requesting to recover a revenue requirement of approximately $17.9 million annually, which was revised to $17.0 million annually on January 31, 2023. The update reflects a decrease of approximately $1.0 million from the revenues currently included in rates. On February 22, 2023, this matter was approved by the NDPSC with rates effective March 1, 2023.

WUTC

On March 24, 2022, Cascade filed a request for tariff revision with the WUTC to rectify an inadvertent IRS normalization violation resulting from its tariff established in 2018 that passes back to customers the reversal of plant-related excess deferred income taxes through an annual rate adjustment. This request was made in response to the issuances of an IRS private letter ruling to another Washington utility with the same annual rate adjustment tariff, which addressed its normalization violations. The private letter ruling concluded the tariff to refund excess deferred income taxes without corresponding adjustments for other components of rate base or changes in depreciation or income tax expense, is an impermissible methodology under the IRS normalization and consistency rules. Cascade's request proposes a similar remedy through the tariff to recover the excess amounts refunded to customers while this tariff has been in place, and revises the method going forward to reflect excess deferred income taxes in rates in the same manner as other components of rate base from its most recent general rate case. Cascade requested recovery of the excess refunded to customers of approximately $3.3 million and elimination of the currently deferred but not yet refunded balance. A multi-party settlement was filed with the WUTC on October 21, 2022. On January 23, 2023, the WUTC denied recovery of the excess refunded to customers, but approved the tariff revision going forward to rectify the inadvertent normalization violation. On February 1, 2023, Cascade filed a motion for clarification with the WUTC on the currently deferred but not yet refunded balance.

FERC

On September 1, 2022, Montana-Dakota filed an update to its transmission formula rate under the MISO tariff for its multi-value project and network upgrade charges for $15.4 million, which was effective January 1, 2023.

On January 27, 2023, WBI Energy Transmission filed a general rate case with the FERC for increases in its transportation and storage services rates that also includes a Greenhouse Gas Cost Recovery Mechanism for anticipated future costs. New rates will be in effect no later than August 1, 2023.

Note 21 - Commitments and Contingencies

The Company is party to claims and lawsuits arising out of its business and that of its consolidated subsidiaries, which may include, but are not limited to, matters involving property damage, personal injury, and environmental, contractual, statutory and regulatory obligations. The Company accrues a liability for those contingencies when the incurrence of a loss is probable and the amount can be reasonably estimated. If a range of amounts can be reasonably estimated and no amount within the range is a better estimate than any other amount, then the minimum of the range is accrued. The Company does not accrue liabilities when the likelihood that the liability has been incurred is probable but the amount cannot be reasonably estimated or when the liability is believed to be only reasonably possible or remote. For contingencies where an unfavorable outcome is probable or reasonably possible and which are material, the Company discloses the nature of the contingency and, in some circumstances, an estimate of the possible loss. Accruals are based on the best information available, but in certain situations management is unable to estimate an amount or range of a reasonably possible loss including, but not limited to when: (1) the damages are unsubstantiated or indeterminate, (2) the proceedings are in the early stages, (3) numerous parties are involved, or (4) the matter involves novel or unsettled legal theories.

At December 31, 2022 and 2021, the Company accrued liabilities which have not been discounted of $32.9 million and $37.0 million, respectively. At December 31, 2022 and 2021, the Company also recorded corresponding insurance receivables of $10.4 million and $14.1 million, respectively, and regulatory assets of $20.9 million and $21.2 million, respectively, related to the accrued liabilities. The accruals are for contingencies resulting from litigation and environmental matters. This includes amounts that have been accrued for matters discussed in Environmental matters within this note. The Company will continue to monitor each matter and adjust accruals as might be warranted based on new information and further developments. Management believes that the outcomes with respect to probable and reasonably possible losses in excess of the amounts accrued, net of insurance recoveries, while uncertain, either cannot be estimated or will not have a material effect upon the Company's financial position, results of operations or cash flows. Unless otherwise required by GAAP, legal costs are expensed as they are incurred.

Environmental matters

Portland Harbor Site In December 2000, Knife River - Northwest was named by the EPA as a PRP in connection with the cleanup of the riverbed site adjacent to a commercial property site acquired by Knife River - Northwest from Georgia-Pacific West, Inc. along the Willamette River. The riverbed site is part of the Portland, Oregon, Harbor Superfund Site where the EPA wants responsible parties to share in the costs of cleanup. The EPA entered into a consent order with certain other PRPs referred to as the Lower Willamette Group for a remedial investigation and feasibility study. The Lower Willamette Group has indicated that it has incurred over $115.0 million in investigation related costs. Knife River - Northwest has joined with approximately 100 other PRPs, including the Lower Willamette Group members, in a voluntary process to establish an allocation of costs for the site. Costs to be allocated would include costs incurred by the Lower Willamette Group as well as costs to implement and fund remediation of the site.

In January 2017, the EPA issued a Record of Decision adopting a selected remedy which is expected to take 13 years to complete with a then estimated present value of approximately $1 billion. Corrective action will not be taken until remedial design/remedial action plans are approved by the EPA. In 2020, the EPA encouraged certain PRPs to enter into consent agreements to perform remedial design covering the entire site and proposed dividing the site into multiple subareas for remedial design. Certain PRPs executed consent agreements for remedial design work and certain others were issued unilateral administrative orders to perform design work. Knife River - Northwest is not subject to either a voluntary agreement or unilateral order to perform remedial design work. In February 2021, the EPA announced that 100 percent of the site's area requiring active cleanup is in the remedial design process. Site-wide remediation activities are not expected to commence for a number of years.

Knife River - Northwest was also notified that the Portland Harbor Natural Resource Trustee Council intends to perform an injury assessment to natural resources resulting from the release of hazardous substances at the site. It is not possible to estimate the costs of natural resource damages until an assessment is completed and allocations are undertaken.

At this time, Knife River - Northwest does not believe it is a responsible party and has notified Georgia-Pacific West, Inc., that it intends to seek indemnity for liabilities incurred in relation to the above matters pursuant to the terms of their sale agreement.

The Company believes it is not probable that it will incur any material environmental remediation costs or damages in relation to the above referenced matter.

Manufactured Gas Plant Sites Claims have been made against Cascade for cleanup of environmental contamination at manufactured gas plant sites operated by Cascade's predecessors and a similar claim has been made against Montana-Dakota for a site operated by Montana-Dakota and its predecessors. Any accruals related to these claims are reflected in regulatory assets. For more information, see Note 6.

Demand has been made of Montana-Dakota to participate in investigation and remediation of environmental contamination at a site in Missoula, Montana. The site operated as a former manufactured gas plant from approximately 1907 to 1938 when it was converted to a butane-air plant that operated until 1956. Montana-Dakota or its predecessors owned or controlled the site for a period of the time it operated as a manufactured gas plant and Montana-Dakota operated the butane-air plant from 1940 to 1951, at which time it sold the plant. There are no documented wastes or by-products resulting from the mixing or distribution of butane-air gas. Preliminary assessment of a portion of the site provided a recommended remedial alternative for that portion of approximately $560,000. However, the recommended remediation would not address any potential contamination to adjacent parcels that may be impacted from historic operations of the manufactured gas plant. An environmental assessment was started in 2020, which is estimated to cost approximately $1.8 million. The environmental assessment report is expected to be submitted to the

MTDEQ in 2024. Montana-Dakota and another party agreed to voluntarily investigate and remediate the site and that Montana-Dakota will pay two-thirds of the costs for further investigation and remediation of the site. Montana-Dakota has accrued costs of $725,000 for the remediation and investigation costs, and has incurred costs of $922,000 as of December 31, 2022. Montana-Dakota received notice from a prior insurance carrier that it will participate in payment of defense costs incurred in relation to the claim. On December 9, 2021, Montana Dakota filed an application with the MTPSC for deferred accounting treatment for costs associated with the investigation and remediation of the site. The MTPSC approved the application for deferred accounting treatment as requested on July 26, 2022.

A claim was made against Cascade for contamination at the Bremerton Gasworks Superfund Site in Bremerton, Washington, which was received in 1997. A preliminary investigation has found soil and groundwater at the site contain impacts requiring further investigation and cleanup. The EPA conducted a Targeted Brownfields Assessment of the site and released a report summarizing the results of that assessment in August 2009. The assessment confirmed that impacts have affected soil and groundwater at the site, as well as sediments in the adjacent Port Washington Narrows. In April 2010, the Washington DOE issued notice it considered Cascade a PRP for hazardous substances at the site. In May 2012, the EPA added the site to the National Priorities List of Superfund sites. Cascade entered into an administrative settlement agreement and consent order with the EPA regarding the scope and schedule for a remedial investigation and feasibility study for the site. Current estimates for the cost to complete the remedial investigation and feasibility study are approximately $12.1 million of which $9.9 million has been incurred as of December 31, 2022. Based on the site investigation, preliminary remediation alternative costs were provided by consultants in August 2020. The preliminary information received through the completion of the data report allowed for the projection of possible costs for a variety of site configurations, remedial measures and potential natural resource damage claims of between $13.6 million and $71.0 million. At December 31, 2022, Cascade has accrued $2.2 million for the remedial investigation and feasibility study, as well as $17.5 million for remediation of this site. The accrual for remediation costs will be reviewed and adjusted, if necessary, after the completion of the feasibility study. In April 2010, Cascade filed a petition with the WUTC for authority to defer the costs incurred in relation to the environmental remediation of this site. The WUTC approved the petition in September 2010, subject to conditions set forth in the order.

A claim was made against Cascade for impacts at a site in Bellingham, Washington. Cascade received notice from a party in May 2008 that Cascade may be a PRP, along with other parties, for impacts from a manufactured gas plant owned by Cascade and its predecessor from about 1946 to 1962. Other PRPs reached an agreed order and work plan with the Washington DOE for completion of a remedial investigation and feasibility study for the site. A feasibility study prepared for one of the PRPs in March 2018 identifies five cleanup action alternatives for the site with estimated costs ranging from $8.0 million to $20.4 million with a selected preferred alternative having an estimated total cost of $9.3 million. The other PRPs developed a cleanup action plan and completed public review in 2020. The development of the remediation design is underway, with the Draft Pre-Remedial Design Investigation Data Report submitted to Washington Ecology in early 2023. The remedy construction is expected to occur following the approval of the final design. Cascade believes its proportional share of any liability will be relatively small in comparison to other PRPs. The plant manufactured gas from coal between approximately 1890 and 1946. In 1946, shortly after Cascade's predecessor acquired the plant, the plant converted to a propane-air gas facility. There are no documented wastes or by-products resulting from the mixing or distribution of propane-air gas. Cascade has recorded an accrual for this site for an amount that is not material.

The Company has received notices from and entered into agreements with certain of its insurance carriers that they will participate in the defense for certain contamination claims subject to full and complete reservations of rights and defenses to insurance coverage. To the extent these claims are not covered by insurance, the Company intends to seek recovery of remediation costs through its natural gas rates charged to customers.

Purchase commitments

The Company has entered into various commitments largely consisting of contracts for natural gas and coal supply; purchased power; natural gas transportation and storage; asphalt oil supply; royalties; information technology; and construction materials. Certain of these contracts are subject to variability in volume and price. The commitment terms vary in length, up to 37 years. The commitments under these contracts as of December 31, 2022, were:

	2023	2024	2025	2026	2027	Thereafter
			(In thousands)			
Purchase commitments	$ 712,875	$ 258,074	$ 158,152	$ 103,677	$ 81,619	$ 676,489

These commitments were not reflected in the Company's consolidated financial statements. Amounts purchased under various commitments for the years ended December 31, 2022, 2021 and 2020, were $1.0 billion, $849.3 million and $666.0 million, respectively.

Guarantees

Certain subsidiaries of the Company have outstanding guarantees to third parties that guarantee the performance of other subsidiaries of the Company. These guarantees are related to construction contracts, insurance deductibles and loss limits, and certain other guarantees. At December 31, 2022, the fixed maximum amounts guaranteed under these agreements aggregated $341.8 million. Certain of the guarantees also have no fixed maximum amounts specified. The amounts of scheduled expiration of the maximum amounts guaranteed under these agreements aggregate to $51.3 million in 2023; $148.4 million in 2024; $126.8 million in 2025; $1.3 million in 2026; $800,000 in 2027; $1.7 million thereafter; and $11.5 million, which has no scheduled maturity date. There were no amounts outstanding under the previously mentioned guarantees at December 31, 2022. In the event of default under these guarantee obligations, the subsidiary issuing the guarantee for that particular obligation would be required to make payments under its guarantee.

Certain subsidiaries have outstanding letters of credit to third parties related to insurance policies and other agreements, some of which are guaranteed by other subsidiaries of the Company. At December 31, 2022, the fixed maximum amounts guaranteed under these letters of credit aggregated $30.0 million. The amounts of scheduled expiration of the maximum amounts guaranteed under these letters of credit aggregate to $29.5 million in 2023 and $500,000 in 2024. There were no amounts outstanding under the previously mentioned letters of credit at December 31, 2022. In the event of default under these letter of credit obligations, the subsidiary guaranteeing the letter of credit would be obligated for reimbursement of payments made under the letter of credit.

In addition, Centennial, Knife River and MDU Construction Services have issued guarantees to third parties related to the routine purchase of maintenance items, materials and lease obligations for which no fixed maximum amounts have been specified. These guarantees have no scheduled maturity date. In the event a subsidiary of the Company defaults under these obligations, Centennial, Knife River or MDU Construction Services would be required to make payments under these guarantees. Any amounts outstanding by subsidiaries of the Company were reflected on the Consolidated Balance Sheet at December 31, 2022.

In the normal course of business, Centennial has surety bonds related to construction contracts and reclamation obligations of its subsidiaries. In the event a subsidiary of Centennial does not fulfill a bonded obligation, Centennial would be responsible to the surety bond company for completion of the bonded contract or obligation. A large portion of the surety bonds is expected to expire within the next 12 months; however, Centennial will likely continue to enter into surety bonds for its subsidiaries in the future. At December 31, 2022, approximately $1.3 billion of surety bonds were outstanding, which were not reflected on the Consolidated Balance Sheet.

Variable interest entities

The Company evaluates its arrangements and contracts with other entities to determine if they are VIEs and if so, if the Company is the primary beneficiary.

Fuel Contract Coyote Station entered into a coal supply agreement with Coyote Creek that provides for the purchase of coal necessary to supply the coal requirements of the Coyote Station for the period May 2016 through December 2040. Coal purchased under the coal supply agreement is reflected in inventories on the Consolidated Balance Sheets and is recovered from customers as a component of electric fuel and purchased power.

The coal supply agreement creates a variable interest in Coyote Creek due to the transfer of all operating and economic risk to the Coyote Station owners, as the agreement is structured so that the price of the coal will cover all costs of operations, as well as future reclamation costs. The Coyote Station owners are also providing a guarantee of the value of the assets of Coyote Creek as they would be required to buy the assets at book value should they terminate the contract prior to the end of the contract term and are providing a guarantee of the value of the equity of Coyote Creek in that they are required to buy the entity at the end of the contract term at equity value. Although the Company has determined that Coyote Creek is a VIE, the Company has concluded that it is not the primary beneficiary of Coyote Creek because the authority to direct the activities of the entity is shared by the four unrelated owners of the Coyote Station, with no primary beneficiary existing. As a result, Coyote Creek is not required to be consolidated in the Company's financial statements.

At December 31, 2022, the Company's exposure to loss as a result of the Company's involvement with the VIE, based on the Company's ownership percentage, was $29.5 million.

Note 22 - Subsequent Events

On January 20, 2023, Cascade entered into a $150.0 million term loan agreement with a SOFR-based variable interest rate and a maturity date of January 19, 2024. The agreement contains customary covenants and provisions, including a covenant of Cascade not to permit, at any time, the ratio of total debt to total capitalization to be greater than 65 percent. The covenants also include certain restrictions on the sale of certain assets, loans and investments.

On January 20, 2023, Intermountain entered into a $125.0 million term loan agreement with a SOFR-based variable interest rate and a maturity date of January 19, 2024. The agreement contains customary covenants and provisions, including a covenant of Intermountain not to permit, at any time, the ratio of total debt to total capitalization to be greater than 65 percent. The covenants also include certain restrictions on the sale of certain assets, loans and investments.

Definitions

The following abbreviations and acronyms used in Notes to Consolidated Financial Statements are defined below:

Abbreviation or Acronym	
AFUDC	Allowance for funds used during construction
ASC	FASB Accounting Standards Codification
ASU	FASB Accounting Standards Update
Big Stone Station	475-MW coal-fired electric generating facility near Big Stone City, South Dakota (22.7 percent ownership)
BSSE	345-kilovolt transmission line from Ellendale, North Dakota, to Big Stone City, South Dakota (50 percent ownership)
Btu	British thermal unit
Cascade	Cascade Natural Gas Corporation, an indirect wholly owned subsidiary of MDU Energy Capital
Centennial	Centennial Energy Holdings, Inc., a direct wholly owned subsidiary of the Company
Centennial Capital	Centennial Holdings Capital LLC, a direct wholly owned subsidiary of Centennial
Company	MDU Resources Group, Inc.
Coyote Creek	Coyote Creek Mining Company, LLC, a subsidiary of The North American Coal Corporation
Coyote Station	427-MW coal-fired electric generating facility near Beulah, North Dakota (25 percent ownership)
EBITDA	Earnings before interest, taxes, depreciation, depletion and amortization
EIN	Employer Identification Number
EPA	United States Environmental Protection Agency
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
Fidelity	Fidelity Exploration & Production Company, a direct wholly owned subsidiary of WBI Holdings (previously referred to as the Company's exploration and production segment)
FIP	Funding improvement plan
GAAP	Accounting principles generally accepted in the United States of America
Great Plains	Great Plains Natural Gas Co., a public utility division of Montana-Dakota
IBEW	International Brotherhood of Electrical Workers
Intermountain	Intermountain Gas Company, an indirect wholly owned subsidiary of MDU Energy Capital
IPUC	Idaho Public Utilities Commission
IRS	Internal Revenue Service
Knife River	Knife River Corporation, a direct wholly owned subsidiary of Centennial
Knife River - Northwest	Knife River Corporation - Northwest, an indirect wholly owned subsidiary of Knife River
K-Plan	Company's 401(k) Retirement Plan
LIBOR	London Inter-bank Offered Rate
MDU Construction Services	MDU Construction Services Group, Inc., a direct wholly owned subsidiary of Centennial
MDU Energy Capital	MDU Energy Capital, LLC, a direct wholly owned subsidiary of the Company
MEPP	Multiemployer pension plan
MISO	Midcontinent Independent System Operator, Inc., the organization that provides open-access transmission services and monitors the high-voltage transmission system in the Midwest United States and Manitoba, Canada and a southern United States region which includes much of Arkansas, Mississippi and Louisiana
MMBtu	Million Btu
MNPUC	Minnesota Public Utilities Commission
Montana-Dakota	Montana-Dakota Utilities Co. a direct wholly owned subsidiary of MDU Energy Capital
MTDEQ	Montana Department of Environmental Quality
MTPSC	Montana Public Service Commission
MW	Megawatt
NDPSC	North Dakota Public Service Commission
PRP	Potentially Responsible Party
RP	Rehabilitation plan
SDPUC	South Dakota Public Utilities Commission
SEC	United States Securities and Exchange Commission
Securities Act	Securities Act of 1933, as amended

SOFR	Secured Overnight Financing Rate
VIE	Variable interest entity
Washington DOE	Washington State Department of Ecology
WBI Energy Transmission	WBI Energy Transmission, Inc., an indirect wholly owned subsidiary of WBI Holdings
WBI Holdings	WBI Holdings, Inc., a direct wholly owned subsidiary of Centennial
WUTC	Washington Utilities and Transportation Commission
Wygen III	100-MW coal-fired electric generating facility near Gillette, Wyoming (25 percent ownership)

Item 9. Changes in and Disagreements With Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

The following information includes the evaluation of disclosure controls and procedures by the Company's chief executive officer and the chief financial officer, along with any significant changes in internal controls of the Company.

Evaluation of Disclosure Controls and Procedures

The term "disclosure controls and procedures" is defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act. The Company's disclosure controls and other procedures are designed to provide reasonable assurance that information required to be disclosed in the reports that the Company files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms. The Company's disclosure controls and other procedures are designed to provide reasonable assurance that information required to be disclosed is accumulated and communicated to management, including the Company's chief executive officer and chief financial officer, to allow timely decisions regarding required disclosure. The Company's management, with the participation of the Company's chief executive officer and chief financial officer, has evaluated the effectiveness of the Company's disclosure controls and other procedures as of the end of the period covered by this report. Based upon that evaluation, the chief executive officer and the chief financial officer have concluded that, as of the end of the period covered by this report, such controls and procedures were effective at a reasonable assurance level.

Changes in Internal Controls

No change in the Company's internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) occurred during the three months ended December 31, 2022, that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting.

Management's Annual Report on Internal Control Over Financial Reporting

The information required by this item is included in this Form 10-K at Item 8 - Management's Report on Internal Control Over Financial Reporting.

Attestation Report of the Registered Public Accounting Firm

The information required by this item is included in this Form 10-K at Item 8 - Report of Independent Registered Public Accounting Firm.

Item 9B. Other Information

None.

Item 9C. Disclosure Regarding Foreign Jurisdictions that Prevent Inspections

None.

Item 10. Directors, Executive Officers and Corporate Governance

Information required by this item will be included in the Company's Proxy Statement, which is incorporated herein by reference.

Item 11. Executive Compensation

Information required by this item will be included in the Company's Proxy Statement, which is incorporated herein by reference.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

Equity Compensation Plan Information

The following table includes information as of December 31, 2022, with respect to the Company's equity compensation plans:

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 stockholders (1)	754,044	(2)	$ —	(3)	2,635,636	(4)(5)
Equity compensation plans not approved by stockholders	N/A		N/A		N/A	
Total	754,044		$ —		2,635,636	

(1) Consists of the Non-Employee Director Long-Term Incentive Compensation Plan and the Long-Term Performance-Based Incentive Plan.
(2) Consists of restricted stock awards and performance share awards.
(3) No weighted average exercise price is shown for the restricted stock awards or performance share awards because such awards have no exercise price.
(4) This amount includes 2,493,022 shares available for future issuance under the Long-Term Performance-Based Incentive Plan in connection with grants of restricted stock, performance units, performance shares or other equity-based awards.
(5) This amount includes 142,614 shares available for future issuance under the Non-Employee Director Long-Term Incentive Compensation Plan.

The remaining information required by this item will be included in the Company's Proxy Statement, which is incorporated herein by reference.

Item 13. Certain Relationships and Related Transactions, and Director Independence

Information required by this item will be included in the Company's Proxy Statement, which is incorporated herein by reference.

Item 14. Principal Accountant Fees and Services

Information required by this item about aggregate fees billed to the Company by its principal accountant, Deloitte & Touche LLP (PCAOB ID No. 34), will be included in the Company's Proxy Statement, which is incorporated herein by reference.

Item 15. Exhibits, Financial Statement Schedules

(a) Financial Statements, Financial Statement Schedules and Exhibits

Index to Financial Statements and Financial Statement Schedules

1. Financial Statements

The following consolidated financial statements required under this item are included under Item 8 - Financial Statements and Supplementary Data. Page

2. Financial Statement Schedules

The following financial statement schedules are included in Part IV of this report. Page

Schedule I - Condensed Financial Information of Registrant (Unconsolidated)

All other schedules have been omitted because they are not applicable or the required information is included elsewhere in the financial statements or related notes.

MDU RESOURCES GROUP, INC.

Schedule I - Condensed Financial Information of Registrant (Unconsolidated)

Condensed Statements of Income and Comprehensive Income

Years ended December 31,	**2022**	2021	2020
		(In thousands)	
Operating revenues	**$ —**	$ —	$ —
Operating expenses	**14,323**	—	—
Operating loss	**(14,323)**	—	—
Other income	**—**	—	—
Interest expense	**—**	—	—
Loss before income taxes	**(14,323)**	—	—
Income taxes	**(1,623)**	—	—
Equity in earnings of subsidiaries from continuing operations	**379,976**	377,731	390,527
Income from continuing operations	**367,276**	377,731	390,527
Equity in earnings (loss) of subsidiaries from discontinued operations	**213**	400	(322)
Net income	**$ 367,489**	$ 378,131	$ 390,205
Comprehensive income	**$ 377,910**	$ 385,205	$ 384,229

The accompanying notes are an integral part of these condensed financial statements.

MDU RESOURCES GROUP, INC.

Schedule I - Condensed Financial Information of Registrant (Unconsolidated)
Condensed Balance Sheets

December 31,	2022	2021
	(In thousands, except shares and per share amounts)	
Assets		
Current assets:		
Cash and cash equivalents	**$ 19,486**	$ 6,159
Receivables, net	**4,410**	6,120
Accounts receivable from subsidiaries	**53,285**	49,696
Prepayments and other current assets	**3,237**	2,528
Total current assets	**80,418**	64,503
Noncurrent assets		
Investments	**50,206**	55,686
Investment in subsidiaries	**3,581,754**	3,368,537
Deferred income taxes	**12,668**	7,364
Operating lease right-of-use assets	**72**	114
Other	**2,068**	26,558
Total noncurrent assets	**3,646,768**	3,458,259
Total assets	**$ 3,727,186**	$ 3,522,762
Liabilities and Stockholders' Equity		
Current liabilities:		
Accounts payable	**$ 2,354**	$ 2,546
Accounts payable to subsidiaries	**4,402**	6,133
Taxes payable	**572**	1,672
Dividends payable	**45,246**	44,229
Accrued compensation	**4,312**	4,098
Operating lease liabilities due within one year	**42**	52
Other accrued liabilities	**17,907**	7,309
Total current liabilities	**74,835**	66,039
Noncurrent liabilities:		
Operating lease liabilities	**30**	62
Other	**65,192**	73,787
Total noncurrent liabilities	**65,222**	73,849
Commitments and contingencies		
Stockholders' equity:		
Common stock Authorized - 500,000,000 shares, $1.00 par value Shares issued - 204,162,814 at December 31, 2022 and 203,889,661 at December 31, 2021	**204,163**	203,889
Other paid-in capital	**1,466,037**	1,461,205
Retained earnings	**1,951,138**	1,762,410
Accumulated other comprehensive loss	**(30,583)**	(41,004)
Treasury stock at cost - 538,921 shares	**(3,626)**	(3,626)
Total stockholders' equity	**3,587,129**	3,382,874
Total liabilities and stockholders' equity	**$ 3,727,186**	$ 3,522,762

The accompanying notes are an integral part of these condensed financial statements.

MDU RESOURCES GROUP, INC.

Schedule I - Condensed Financial Information of Registrant (Unconsolidated)
Condensed Statements of Cash Flows

Years ended December 31,	2022	2021	2020
		(In thousands)	
Net cash provided by operating activities	**$ 242,199**	$ 187,297	$ 226,642
Investing activities:			
Investments in and advances to subsidiaries	**(45,000)**	(102,000)	(67,000)
Investments	**(885)**	(391)	(4)
Net cash used in investing activities	**(45,885)**	(102,391)	(67,004)
Financing activities:			
Proceeds from issuance of common stock	**(149)**	88,767	3,385
Dividends paid	**(176,915)**	(171,354)	(166,405)
Repurchase of common stock	**(3,525)**	(2,992)	—
Tax withholding on stock-based compensation	**(2,398)**	(1,949)	(163)
Net cash used in financing activities	**(182,987)**	(87,528)	(163,183)
Increase (decrease) in cash and cash equivalents	**13,327**	(2,622)	(3,545)
Cash and cash equivalents - beginning of year	**6,159**	8,781	12,326
Cash and cash equivalents - end of year	**$ 19,486**	$ 6,159	$ 8,781

The accompanying notes are an integral part of these condensed financial statements.

Notes to Condensed Financial Statements

Note 1 - Summary of Significant Accounting Policies

Basis of presentation The condensed financial information reported in Schedule I is being presented to comply with Rule 12-04 of Regulation S-X. The information is unconsolidated and is presented for the parent company only, MDU Resources Group, Inc. (the Company) as of and for the years ended December 31, 2022, 2021 and 2020. In Schedule I, investments in subsidiaries are presented under the equity method of accounting where the assets and liabilities of the subsidiaries are not consolidated. The investments in net assets of the subsidiaries are recorded on the Condensed Balance Sheets. The income from subsidiaries is reported as equity in earnings of subsidiaries on the Condensed Statements of Income. The material cash inflows on the Condensed Statements of Cash Flows are primarily from the dividends and other payments received from its subsidiaries and the proceeds raised from the issuance of equity securities. The consolidated financial statements of the Company reflect certain businesses as discontinued operations. These statements should be read in conjunction with the consolidated financial statements and notes thereto of the Company.

Earnings per common share Please refer to the Consolidated Statements of Income of the registrant for earnings per common share. In addition, see Item 8 - Note 2 for information on the computation of earnings per common share.

Note 2 - Debt At December 31, 2022, the Company had no long-term debt maturities. For more information on debt, see Item 8 - Note 9.

Note 3 - Dividends The Company depends on earnings and dividends from its subsidiaries to pay dividends on common stock. Cash dividends paid to the Company by subsidiaries were $242.1 million, $188.1 million and $228.4 million for the years ended December 31, 2022, 2021 and 2020, respectively.

Exhibits

			Incorporated by Reference				
Exhibit Number	Exhibit Description	Filed Herewith	Form	Period Ended	Exhibit	Filing Date	File Number
3(a)	Amended and Restated Certificate of Incorporation of MDU Resources Group, Inc.		8-K		3.2	5/8/19	1-03480
3(b)	Amended and Restated Bylaws of MDU Resources Group, Inc.		8-K		3.1	2/15/19	1-03480
4(a)	Indenture, dated as of December 15, 2003, between MDU Resources Group, Inc. and The Bank of New York, as trustee		S-8		4(f)	1/21/04	333-112035
4(b)	First Supplemental Indenture, dated as of November 17, 2009, between MDU Resources Group, Inc. and the Bank of New York Mellon, as trustee		10-K	12/31/09	4(c)	2/17/10	1-03480
*4(c)	Fifth Amended and Restated Credit Agreement, dated as of December 19, 2019, among Centennial Energy Holdings, Inc., U.S. Bank National Association, as Administrative Agent, and The Several Financial Institutions party thereto		10-K	12/31/19	4(c)	2/21/20	1-03480
*4(d)	Montana-Dakota Utilities Co. Amended and Restated Credit Agreement, dated December 19, 2019, among Montana-Dakota Utilities Co., Various Lenders, and Wells Fargo Bank, National Association, as Administrative Agent		10-K	12/31/19	4(d)	2/21/20	1-03480
4(e)	Centennial Energy Holdings, Inc. Note Purchase Agreement, dated December 20, 2012, among Centennial Energy Holdings, Inc. and various purchasers of the notes		10-Q	6/30/19	4(a)	8/2/19	1-03480
4(f)	Montana-Dakota Utilities Co. Note Purchase Agreement, dated July 24, 2019, among Montana-Dakota Utilities Co. and various purchasers of the notes		10-Q	9/30/19	4(a)	11/1/19	1-03480
4(g)	MDU Resources Group, Inc. Description of Securities Registered Pursuant to Section 12 of the Securities and Exchange Act of 1934		10-K	12/31/19	4(g)	2/21/20	1-03480
*4(h)	WBI Energy Transmission, Inc. Second Amendment and Restatement Note Purchase and Private Shelf Agreement, effective as of December 22, 2022, among Prudential Investment Management, Inc. and certain investors described therein	X					
+10(a)	MDU Resources Group, Inc. Supplemental Income Security Plan, as amended and restated May 10, 2017		10-Q	6/30/17	10(d)	8/4/17	1-03480
+10(b)	MDU Resource Group, Inc. Director Compensation Policy, as amended May 11, 2022		10-Q	6/30/22	10(b)	8/5/22	1-03480
+10(c)	Deferred Compensation Plan for Directors, as amended May 15, 2008		10-Q	6/30/08	10(a)	8/7/08	1-03480
+10(d)	Non-Employee Director Stock Compensation Plan, as amended May 12, 2011		10-Q	6/30/11	10(a)	8/5/11	1-03480
+10(e)	MDU Resources Group, Inc. Non-Employee Director Long-Term Incentive Compensation Plan, as amended May 17, 2012		10-Q	6/30/12	10(a)	8/7/12	1-03480
+10(f)	MDU Resources Group, Inc. Long-Term Performance-Based Incentive Plan, as amended February 11, 2016		10-K	12/31/15	10(f)	2/19/16	1-03480
+10(g)	MDU Resources Group, Inc. Executive Incentive Compensation Plan, as amended November 12, 2020, and Rules and Regulations, as amended November 12, 2020		10-K	12/31/20	10(h)	2/19/21	1-03480
+10(h)	Form of Performance Share Award Agreement under the Long-Term Performance-Based Incentive Plan, as amended February 13, 2020		10-K	12/31/19	10(k)	2/21/20	1-03480
+10(i)	Form of Performance Share Award Agreement under the Long-Term Performance-Based Incentive Plan, as amended February 11, 2021		10-K	12/31/20	10(l)	2/19/21	1-03480
+10(j)	Form of Performance Share Award Agreement under the Long-Term Performance-Based Incentive Plan, as amended February 17, 2022		10-K	12/31/21	10(k)	2/23/22	1-03480

			Incorporated by Reference				
Exhibit Number	Exhibit Description	Filed Herewith	Form	Period Ended	Exhibit	Filing Date	File Number
+10(k)	Restricted Stock Unit Award Agreement under the Long-Term Performance-Based Incentive Plan, as amended February 11, 2021		10-K	12/31/20	10(n)	2/19/21	1-03480
+10(l)	Restricted Stock Unit Award Agreement under the Long-Term Performance-Based Incentive Plan, as amended February 17, 2022		10-K	12/31/21	10(m)	2/23/22	1-03480
+10(m)	Restricted Stock Unit Award Agreement under the Long-Term Performance-Based Incentive Plan, as amended February 16, 2023	X					
+10(n)	Form of MDU Resources Group, Inc. Indemnification Agreement for Section 16 Officers and Directors, dated May 15, 2014		8-K		10.1	5/15/14	1-03480
+10(o)	Form of Amendment No. 1 to Indemnification Agreement, dated May 15, 2014		8-K		10.2	5/15/14	1-03480
+10(p)	MDU Resources Group, Inc. Section 16 Officers and Directors with Indemnification Agreements Chart, as of February 1, 2023	X					
+10(q)	MDU Resources Group, Inc. Nonqualified Defined Contribution Plan, as amended and restated November 12, 2020		10-K	12/31/20	10(r)	2/19/21	1-03480
+10(r)	MDU Resources Group, Inc. Deferred Compensation Plan Adoption Agreement, as amended August 12, 2021		10-Q	9/30/21	10(c)	11/4/21	1-03480
+10(s)	MDU Resources Group, Inc. Deferred Compensation Plan Document, dated November 12, 2020		8-K		10.2	11/12/20	1-03480
+10(t)	MDU Resources Group, Inc. 401(k) Retirement Plan, as restated April 1, 2020		10-Q	3/31/20	10(a)	5/8/20	1-03480
+10(u)	MDU Resources Group, Inc. 401(k) Retirement Plan, as amended January 1, 2022		10-K	12/31/21	10(w)	2/23/22	1-03480
+10(v)	MDU Resources Group, Inc. 401(k) Retirement Plan, as amended August 17, 2022		10-Q	9/30/22	10(a)	11/3/22	1-03480
+10(w)	MDU Resources Group, Inc. 401(k) Retirement Plan, as amended December 28, 2022	X					
+10(x)	Employment Letter for Jeffrey S. Thiede, dated May 16, 2013		10-K	12/31/13	10(ab)	2/21/14	1-03480
+10(y)	Jason L. Vollmer Offer Letter, dated September 20, 2017		8-K		10.1	9/21/17	1-03480
+10(z)	Cooperation Agreement, dated as of January 24, 2023, by and among Keith A. Meister, Corvex Management LP and MDU Resources Group, Inc.		8-K		10.1	1/24/23	1-03480
+10(aa)	Retention Agreement for Jeffrey S. Thiede, dated February 17, 2023	X					
+10(ab)	David C. Barney Offer Letter, dated February 17, 2023	X					
21	Subsidiaries of MDU Resources Group, Inc.	X					
23	Consent of Independent Registered Public Accounting Firm	X					
31(a)	Certification of Chief Executive Officer filed pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	X					
31(b)	Certification of Chief Financial Officer filed pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	X					
32	Certification of Chief Executive Officer and Chief Financial Officer furnished pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002	X					
95	Mine Safety Disclosures	X					
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 Taxonomy Extension Schema Document						

Exhibit Number	Exhibit Description	Filed Herewith	Incorporated by Reference Form	Period Ended	Exhibit	Filing Date	File Number
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document						
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document						
101.LAB	XBRL Taxonomy Extension Label Linkbase Document						
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document						

* Schedules and exhibits to this agreement have been omitted pursuant to Item 601(a)(5) of Regulation S-K. A copy of any omitted schedule and/or exhibit will be furnished as a supplement to the SEC upon request.

+ Management contract, compensatory plan or arrangement.

MDU Resources Group, Inc. agrees to furnish to the SEC upon request any instrument with respect to long-term debt that MDU Resources Group, Inc. has not filed as an exhibit pursuant to the exemption provided by Item 601(b)(4)(iii)(A) of Regulation S-K.

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.

MDU Resources Group, Inc.

Date:	February 24, 2023	By:	/s/ David L. Goodin
			David L. Goodin (President and Chief 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 in the capacities and on the date indicated.

Signature	Title	Date
/s/ David L. Goodin David L. Goodin (President and Chief Executive Officer)	Chief Executive Officer and Director	February 24, 2023
/s/ Jason L. Vollmer Jason L. Vollmer (Vice President and Chief Financial Officer)	Chief Financial Officer	February 24, 2023
/s/ Stephanie A. Barth Stephanie A. Barth (Vice President, Chief Accounting Officer and Controller)	Chief Accounting Officer	February 24, 2023
/s/ Dennis W. Johnson Dennis W. Johnson (Chair of the Board)	Director	February 24, 2023
/s/ German Carmona Alvarez German Carmona Alvarez	Director	February 24, 2023
/s/ Thomas Everist Thomas Everist	Director	February 24, 2023
/s/ Karen B. Fagg Karen B. Fagg	Director	February 24, 2023
/s/ Patricia L. Moss Patricia L. Moss	Director	February 24, 2023
/s/ Dale S. Rosenthal Dale S. Rosenthal	Director	February 24, 2023
/s/ Edward A. Ryan Edward A. Ryan	Director	February 24, 2023
/s/ David M. Sparby David M. Sparby	Director	February 24, 2023
/s/ Chenxi Wang Chenxi Wang	Director	February 24, 2023

MDU RESOURCES
GROUP, INC.

David L. Goodin
President and
Chief Executive Officer

1200 W. Century Ave.
Bismarck, ND 58503
Mailing address:
P.O. Box 5650
Bismarck, ND 58506-5650
(701) 530-1000
www.MDU.com

March 24, 2023

Fellow Stockholders:

I invite you to attend our annual meeting at 11 a.m. CDT May 9, 2023, at 909 Airport Road in Bismarck, North Dakota, where you will have the opportunity to engage with our Board of Directors and senior management team. Please check our website at www.mduproxy.com for additional information about our meeting.

During the meeting, we will hear the results of stockholder voting on the items outlined in this Proxy Statement, including election of our Board of Directors, the advisory votes regarding the frequency of voting on and the compensation paid to our named executive officers, and ratification of our independent auditors. I encourage you to promptly follow the instructions on your notice or proxy card to vote your shares on these items.

We had very strong operational performance in 2022. I look forward to sharing with you our results as well as the strong growth trajectory we believe we are on at each of our businesses, with an all-time high combined backlog of more than $3 billion of work at our construction businesses and planned capital investments of $2.5 billion over the next five years at our regulated energy delivery businesses.

I will give an update on the great progress we're making toward completing the anticipated separation of Knife River Corporation into an independent, publicly traded company and the strategic review of MDU Construction Services Group, Inc. We expect both initiatives to be complete in the second quarter as we work to optimize value for you, our shareholders, by working to create two pure-play, publicly traded companies, with one focused on regulated energy delivery and the other on construction materials.

I appreciate your continued investment in MDU Resources and look forward to visiting with you May 9.

Sincerely,

David L. Goodin
President and Chief Executive Officer

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MDU RESOURCES
GROUP, INC.

1200 West Century Avenue
Mailing Address:
P.O. Box 5650
Bismarck, North Dakota 58506-5650
(701) 530-1000

NOTICE OF ANNUAL MEETING OF STOCKHOLDERS TO BE HELD May 9, 2023

March 24, 2023

NOTICE IS HEREBY GIVEN that the Annual Meeting of Stockholders of MDU Resources Group, Inc. will be held at 909 Airport Road, Bismarck, North Dakota 58504, on Tuesday, May 9, 2023, at 11:00 a.m., Central Daylight Saving Time, for the following purposes:

Items of Business

1. Election of directors;
2. Advisory vote to approve the frequency of future advisory votes to approve the compensation paid to the company's named executive officers;
3. Advisory vote to approve the compensation paid to the company's named executive officers;
4. Ratification of the appointment of Deloitte & Touche LLP as the company's independent registered public accounting firm for 2023; and
5. Transaction of any other business that may properly come before the meeting or any adjournment(s) thereof.

Record Date

The board of directors has set the close of business on March 10, 2023, as the record date for the determination of stockholders who will be entitled to notice of, and to vote at, the meeting and any adjournment(s) thereof.

Meeting Attendance

All stockholders as of the record date of March 10, 2023, are cordially invited to attend the annual meeting. You must request an admission ticket to attend. If you are a stockholder of record and plan to attend the meeting, please contact MDU Resources Group, Inc. by email at CorporateSecretary@mduresources.com or by telephone at 701-530-1010 to request an admission ticket. A ticket will be sent to you by mail.

If your shares are held beneficially in the name of a bank, broker, or other holder of record, and you plan to attend the annual meeting, you will need to submit a written request for an admission ticket by mail to: Investor Relations, MDU Resources Group, Inc., P.O. Box 5650, Bismarck, ND 58506 or by email at CorporateSecretary@mduresources.com. The request must include proof of stock ownership as of March 10, 2023, such as a bank or brokerage firm account statement or a legal proxy from the bank, broker, or other holder of record confirming ownership. A ticket will be sent to you by mail.

Requests for admission tickets must be received no later than May 2, 2023. You must present your admission ticket and state-issued photo identification, such as a driver's license, to gain admittance to the meeting.

Proxy Materials

This Proxy Statement will first be sent to stockholders requesting written materials on or about March 24, 2023. A Notice of Availability of Proxy Materials (Notice) will also be sent to certain stockholders on or about March 24, 2023. The Notice contains basic information about the annual meeting and instructions on how to view our proxy materials and vote online.

By order of the Board of Directors,

Karl A. Liepitz
Secretary

Important Notice Regarding the Availability of Proxy Materials for the Stockholders Meeting to be Held on May 9, 2023. The 2023 Notice of Annual Meeting and Proxy Statement and 2022 Annual Report to Stockholders are available at www.mduproxy.com.

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EXECUTIVE COMPENSATION (continued)

AUDIT MATTERS

INFORMATION ABOUT THE ANNUAL MEETING

MDU RESOURCES
GROUP, INC.
Building a Strong America®

Cautionary information and forward-looking statements. This Proxy Statement contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. From time to time, we may also provide oral or written forward-looking statements in other materials we release to the public. Such forward-looking statements are subject to the safe harbor created by the Private Securities Litigation Reform Act of 1995.

Forward-looking statements are all statements other than statements of historical fact, including without limitation those statements that are identified by the words "anticipates," "estimates," "expects," "intends," "plans," "predicts" and similar expressions, and include statements concerning plans, trends, objectives, goals, strategies, including the anticipated separation of Knife River Corporation or the proposed future structure of two pure-play publicly traded companies, future events, or performance, and underlying assumptions (many of which are based, in turn, upon further assumptions) and other statements that are other than statements of historical facts. Forward-looking statements involve risks and uncertainties, which could cause actual results or outcomes to differ materially from those expressed.

Forward-looking statements are subject to risks and uncertainties that could cause actual results to be materially different from those indicated (both favorably and unfavorably). These risks and uncertainties include, but are not limited to, those described in Part I—Item 1A “Risk Factors” in our 2022 Annual Report on Form 10-K (2022 Form 10-K) and subsequent Securities and Exchange Commission (SEC) filings. Caution should be taken not to place undue reliance on any such forward-looking statements. We undertake no obligation to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise, except as required by applicable law. Website references throughout this document are provided for convenience only, and the content on the referenced websites is not incorporated by reference into this document.

PROXY STATEMENT SUMMARY

To assist you in reviewing the company's 2022 performance and voting your shares, we call your attention to key elements of our 2023 Proxy Statement. The following is only a summary and does not contain all the information you should consider. You should read the entire Proxy Statement carefully before voting. For more information about these topics, please review the full Proxy Statement and our 2022 Annual Report to Stockholders.

Annual Meeting Information

Meeting Information

Time and Date
11:00 a.m. Central Daylight Saving Time Tuesday, May 9, 2023
Place
MDU Service Center 909 Airport Road Bismarck, ND 58504

Summary of Stockholder Voting Matters

Voting Matters		Board Vote Recommendation	See Page
Item 1.	Election of Directors	FOR Each Nominee	16
Item 2.	Advisory Vote to Approve the Frequency of Future Advisory Votes to Approve the Compensation Paid to the Company's Named Executive Officers	FOR One Year	42
Item 3.	Advisory Vote to Approve the Compensation Paid to the Company's Named Executive Officers	FOR	43
Item 4.	Ratification of the Appointment of Deloitte & Touche LLP as the Company's Independent Registered Public Accounting Firm for 2023	FOR	81

Who Can Vote

If you held shares of MDU Resources Group, Inc. common stock at the close of business on March 10, 2023, you are entitled to vote at the annual meeting. You are encouraged to vote in advance of the meeting using one of the following voting methods.

How to Vote

Registered Stockholders

If your shares are held directly with our stock registrar, you can vote any one of four ways:

By Internet: Go to the website shown on the Notice of Availability of Proxy Materials (Notice) or Proxy Card, if you received one, and follow the instructions.

By Telephone: Call the telephone number shown on the Notice or Proxy Card, if you received one, and follow the instructions given by the voice prompts.

Voting via the Internet or by telephone authorizes the named proxies to vote your shares in the same manner as if you marked, signed, dated, and returned the Proxy Card by mail. Your voting instructions may be transmitted up until 11:59 p.m. Eastern Time on May 8, 2023.

By Mail: If you received a paper copy of the Proxy Statement, Annual Report, and Proxy Card, mark, sign, date, and return the Proxy Card in the postage-paid envelope provided.

In Person: Attend the annual meeting, or send a personal representative with an appropriate proxy, to vote by ballot at the meeting.

Beneficial Stockholders

If you held shares beneficially in the name of a bank, broker, or other holder of record (sometimes referred to as holding shares "in street name"), you will receive voting instructions from said bank, broker, or other holder of record. **If you wish to vote in person at the meeting, you must obtain a legal proxy from your bank, broker, or other holder of record of your shares and present it at the meeting.**

Company Overview

MDU Resources is Building a Strong America®

A strong infrastructure is the heart of our country's economy. It is the natural gas and electricity that power business, industry, and our daily lives. It is the pipes and wires that connect our homes, factories, offices and stores to bring them to life. It is the transportation network of roads, highways, and airports that keeps our economy moving. Infrastructure is our business.

Our Vision

With integrity, Building a Strong America® while being a great and safe place to work.

Our Mission

Deliver superior value to stakeholders by providing essential infrastructure and services to America.

Our Integrity Code

Commitment to Integrity	We will conduct business legally and ethically with our best skills and judgment.
Commitment to Shareholders	We will act in the best interests of our corporation and protect its assets.
Commitment to Employees	We will work together to provide a safe and positive workplace.
Commitment to Customers, Suppliers and Competitors	We will compete in business only by lawful and ethical means.
Commitment to Communities	We will be a responsible and valued corporate citizen.

Our Strategy

Deliver superior value and achieve industry-leading performance with two pure-play companies of regulated energy delivery and construction materials, while pursuing organic growth opportunities and strategic acquisitions of well-managed companies and properties.

Our Businesses

Electric and Natural Gas Utilities

Our utility companies serve more than 1.18 million customers across eight states.

Pipeline

We provide natural gas transportation, underground natural gas storage, cathodic protection and other energy-related services.

Construction Materials and Contracting

Knife River Corporation is a Top 10 producer of aggregates in America, has approximately 1.1 billion tons of aggregate reserves, and employs more than 5,000 people during peak construction season.

Construction Services

MDU Construction Services Group, Inc. is one of the largest electrical contractors in the United States, with approximately 9,000 employees.

Business Performance Highlights

Future Structure of MDU Resources

The company's board of directors has determined the future company structure that is most likely to maximize long-term value for stockholders is to create two pure-play publicly traded companies, one focused on regulated energy delivery and the other on construction materials. To achieve this future structure, the company is working toward a separation of Knife River Corporation to create a standalone leading construction materials company, and it is evaluating options to optimize the value of its construction services business, with the review expected to be complete in the second quarter of 2023.

In addition to pursuing each of these strategic initiatives, all of our business segments performed well despite inflationary pressures and supply chain challenges throughout 2022.

Regulated Energy Delivery

- **Continued Growth with New Customers.** Over 18,000 new customers were connected to our utilities system, representing customer growth of 1.6%.
- **Investing in Electric Generation.** The electric segment continues to make progress toward reducing its greenhouse gas emissions. In 2022, operations were ceased at the company's last wholly owned coal-fired electric generating facility, Heskett Station Units 1 and 2 in Mandan, North Dakota. Construction of Heskett Station Unit 4, an 88-megawatt natural-gas fired simple-cycle combustion turbine, is expected to be complete in the summer of 2023.
- **Joint Regional Transmission Line Project.** The electric segment and Otter Tail Power Company announced another Midcontinent Independent System Operator-approved joint regional transmission line project. Together, the companies plan to develop, construct and co-own a 95-mile, 345-kilovolt transmission line that would span from Jamestown to Ellendale in North Dakota. We expect the project to create a more resilient regional transmission grid, helping to ensure reliable and affordable electric service to our customers.
- **Natural Gas Pipeline Expansion.** The pipeline segment put the North Bakken Expansion project into service on February 1, 2022 and has announced other significant growth projects in various stages and pending regulatory approvals, including the 2023 Line Section 27 Expansion project in northwestern North Dakota expecting to add natural gas transportation capacity of 175 million cubic feet per day; Grasslands South Expansion from western North Dakota to northern Wyoming, which is expected to add natural gas transportation capacity of 94 million cubic feet per day; and Line Section 15 Expansion in western South Dakota, which is expected to add natural gas transportation capacity of 25 million cubic feet per day.

Construction Materials & Services

- **Record Revenues.** The construction materials segment had record revenues of $2.53 billion in 2022 and earnings of $116.2 million, compared to revenues of $2.23 billion and earnings of $129.8 million in 2021. Demand remained strong for construction materials and contracting work as evidenced by a record backlog at December 31, 2022 of $935 million, up 32% compared to $708 million at December 31, 2021.
- **Growth Opportunities.** The construction materials and contracting segment continued its growth through acquisitions in 2022. Allied Concrete and Supply Co., a producer of ready-mixed concrete in California, was acquired in December 2022. In addition to pursuing additional acquisitions, the segment expects ongoing growth opportunities, including through projects that result from the U.S. Infrastructure Investment and Jobs Act that provides approximately $650 billion of reauthorized funds for the Department of Transportation surface transportation program and $550 billion of new infrastructure funds.

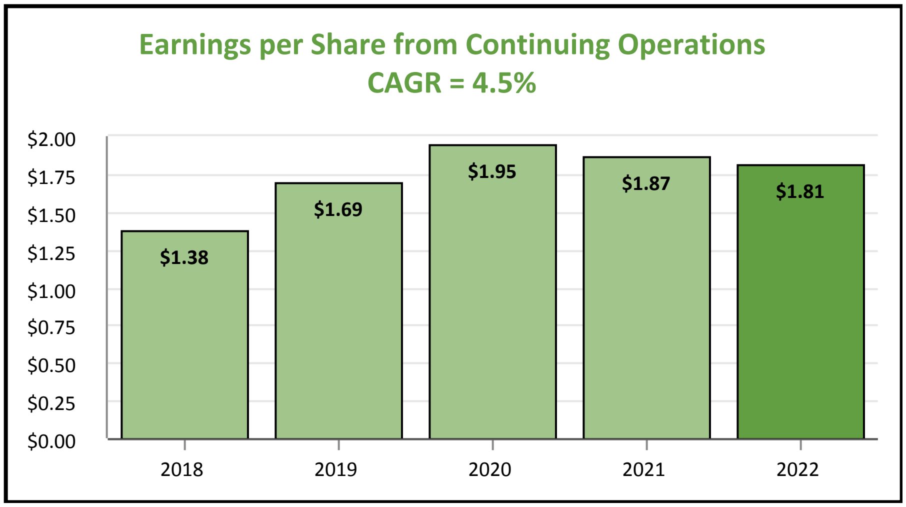
- **Record Revenues.** The construction services segment earned record revenues of $124.8 million in 2022, compared to $109.4 million in 2021. Revenues were a record $2.70 billion, compared to $2.05 billion in 2021. Demand continues to be extremely strong for construction services work, with the construction services having a record backlog of $2.13 billion at December 31, 2022, up, 54% compared to $1.38 billion at December 31, 2021.
- **Renewable Electric Generation Project.** The construction services segment continues to emphasize its premier services for renewable electric generation projects. The construction services segment subsidiary completed construction in October 2022 on a 200-megawatt solar facility in Moapa, Nevada, installing 621,093 solar modules, as well as ancillary facilities for the project.

Performance from Continuing Operations

	2018	2019	2020	2021	2022
Electric Distribution					
Retail Sales (million kWh)	3,354.4	3,314.3	3,204.5	3,271.6	3,343.9
Customers	143,022	143,346	143,782	144,103	144,561
Natural Gas Distribution					
Retail Sales (MMdk)	112.6	123.7	114.5	115.3	131.2
Transportation (MMdk)	149.5	166.1	160.0	174.4	167.7
Customers	957,727	977,468	997,146	1,016,670	1,034,821
Pipeline Transportation (MMdk)	351.5	429.7	438.6	471.1	482.9
Construction Materials and Contracting Revenues (millions)	$1,925.9	$2,190.7	$2,178.0	$2,228.9	$2,534.7
Construction Services Revenues (millions)	$1,371.5	$1,849.3	$2,095.7	$2,051.6	$2,699.2

Financial Performance Highlights

- The company achieved earnings of $367.5 million, or $1.81 per share.
- Our return on invested capital in 2022 was 7.1%.
- The chart below shows our earnings per share from continuing operations and compound annual growth rate (CAGR) of 4.5% over the last five years.



- Returned $178 million to stockholders through dividends during 2022:
  - ☐ Increased annual dividend for the 32nd straight year to 87.5 cents per share paid during 2022;
  - ☐ Paid uninterrupted dividends for 85 straight years; and
  - ☐ Member of the elite S&P High-Yield Dividend Aristocrats Index which recognizes companies within the S&P Composite 1500 Index that have followed a managed dividend policy of consistently increasing dividends annually for at least 20 years.
- Member of the S&P MidCap 400.

32 Years
of Consecutive
Dividend Increases

Dividends Paid
$836 Million
Over the Last 5 Years

85 Years
of Uninterrupted
Dividend Payments

Corporate Governance Practices

MDU Resources is committed to strong corporate governance aligned with stockholder interests. The board, through its nominating and governance committee, regularly monitors leading practices in governance and adopts measures that it determines are in the best interests of the company and its stockholders. The following highlights our corporate governance practices and policies. See the sections entitled "Corporate Governance" and "Executive Compensation" for more information on the following:

- ✓ **Annual Election of All Directors**
- ✓ **Majority Voting for Directors**
- ✓ **No Shareholder Rights Plan**
- ✓ **Succession Planning and Implementation Process**
- ✓ **Separate Board Chair and CEO**
- ✓ **Executive Sessions of Independent Directors at Every Regularly Scheduled Board Meeting**
- ✓ **Annual Board and Committee Self-Evaluations**
- ✓ **Risk Oversight by Full Board and Committees**
- ✓ **Environmental and Social Oversight by Full Board and Board Committee**
- ✓ **Proxy Access for Stockholders**
- ✓ **All Directors are Independent Other Than Our CEO**
- ✓ **Standing Committees Consist Entirely of Independent Directors**
- ✓ **Active Investor Outreach Program**
- ✓ **One Class of Stock**
- ✓ **Stock Ownership Requirements for Directors and Executive Officers**
- ✓ **Anti-Hedging and Anti-Pledging Policies for Directors and Executive Officers**
- ✓ **No Related Party Transactions by Our Directors or Executive Officers**
- ✓ **Compensation Recovery/Clawback Policy**
- ✓ **Annual Advisory Approval on Executive Compensation**
- ✓ **Mandatory Retirement for Directors at Age 76**
- ✓ **Directors May Not Serve on More Than Three Public Boards Including the Company's Board**
- ✓ **Diverse Board in Terms of Gender, Race, Experience, Skills and Tenure**

Recognition for Gender Diversity

MDU Resources was recognized in 2022 for gender diversity on its board of directors:

50/50 Women on Boards$^{\text{TM}}$ as a "3+" company for having three or more women on its board of directors.

Director Nominees

The board recommends a vote FOR the election of each of the following nominees for director. Ten directors stand for election. Additional information about each director's background and experience can be found beginning on page 16.

Name	Age	Director Since	Primary Occupation	Board Committees
German Carmona Alvarez	54	2022	Global president of applied intelligence of Wood PLC	• Compensation • Nominating and Governance
Thomas Everist	73	1995	President and chair of The Everist Company, an investment and land development company, formerly engaged in aggregate, concrete, and asphalt production	• Compensation • Nominating and Governance
Karen B. Fagg	69	2005	Former vice president of DOWL LLC, dba DOWL HKM, an engineering and design firm	• Compensation (Chair) • Environmental and Sustainability
David L. Goodin	61	2013	President and chief executive officer, MDU Resources Group, Inc.	Executive officer
Dennis W. Johnson	73	2001	Chair, president, and chief executive officer of TMI Group Incorporated, manufacturers of casework and architectural woodwork	Chair of the board
Patricia L. Moss	69	2003	Former president and chief executive officer of Cascade Bancorp, a financial holding company, subsequently merged into First Interstate Bank	• Compensation • Environmental and Sustainability (Chair)
Dale S. Rosenthal	66	2021	Former senior executive, including strategic director, division president of Clark Financial Group, and chief financial officer of Clark Construction Group, a building and civil construction firm	• Audit • Nominating and Governance
Edward A. Ryan	69	2018	Former executive vice president and general counsel of Marriott International	• Audit • Nominating and Governance (Chair)
David M. Sparby	68	2018	Former senior vice president and group president, revenue, of Xcel Energy and president and chief executive officer of its subsidiary, NSP-Minnesota	• Audit (Chair) • Environmental and Sustainability
Chenxi Wang	52	2019	Founder and managing general partner of Rain Capital Fund, L.P., a cybersecurity-focused venture fund	• Audit • Environmental and Sustainability

Independence

●●●●●
●●●●○

90%

The board has determined that all director nominees, other than Mr. Goodin, meet the independence standards set by the NYSE and SEC.

Board Refreshment

●

New Members

+5

Five new members have been elected or appointed to the board over the last five years.

Tenure

0-4 Years	●●●	**Average Tenure** **11.5 Years**
5-10 Years	●●●	
11+ Years	●●●●	

The average tenure of the director nominees reflects a balance of company experience and new perspective.

Diversity

Gender	
Four director nominees are women.	**40%**
Race/Ethnicity	
Two director nominees are ethnically diverse.	**20%**

In addition to the director nominees described above, on January 24, 2023, the company entered into a cooperation agreement (Cooperation Agreement) with Corvex Management LP, pursuant to which Corvex Management LP partner, James H. Gemmel, was appointed as a non-voting board observer and, subject to Federal Energy Regulatory Commission (FERC) approval, to the board of directors. For further details on the Cooperation Agreement, see the section entitled "Corporate Governance."

Compensation Highlights

The company's executive compensation is based on providing market competitive compensation opportunities to attract top talent focused on achievement of short and long-term business results. Our compensation program is structured to align compensation with the company's financial performance as a substantial portion of our executive compensation is directly linked to performance incentive awards.

- Over 80% of our chief executive officer's target compensation and approximately 70% of our other named executive officers' target compensation are at risk.
- 100% of our named executive officers' annual incentive and 75% of their long-term incentive are performance-based and tied to performance against pre-established, specific, measurable goals. Time-vesting restricted stock units represent 25% of our named executive officers' long-term incentive and require the executive to remain employed with the company through the vesting period.
- We require our executive officers to own a significant amount of company stock based upon a multiple of their base salary.
- The 2022 annual cash incentive award program for executive officers included a diversity, equity and inclusion performance modifier based upon the company's achievement of certain measures to attract, retain, and develop a diverse and inclusive workforce.

2022 Named Executive Officer Target Pay Mix

At the 2022 Annual Meeting, the company's advisory vote to approve executive compensation received support from over 95% of the common stock represented at the meeting and entitled to vote on the matter.

Key Features of Our Executive Compensation Program

What We Do

- ☑ **Pay for Performance** - Annual incentive and the performance share award portion of the long-term incentive are tied to performance measures set by the compensation committee and comprise the largest portion of executive compensation.
- ☑ **Independent Compensation Committee** - All members of the compensation committee meet the independence standards under the New York Stock Exchange listing standards and the Securities and Exchange Commission rules.
- ☑ **Independent Compensation Consultant** - The compensation committee retains an independent compensation consultant to evaluate executive compensation plans and practices.
- ☑ **Competitive Compensation** - Executive compensation reflects executive performance, experience, relative value compared to other positions within the company, relationship to competitive market value compensation, corporate and business segment economic environment, and the actual performance of the overall company and the business segments.
- ☑ **Annual Cash Incentive** - Payment of annual cash incentive awards is based on overall company performance measured in terms of earnings per share in addition to business segment performance measured in terms of pre-established annual financial measures for business segment executives.
- ☑ **Long-Term Equity Incentive** - 2022 long-term incentive awards may be earned at the end of a three-year period. Payment of performance share awards, which represent 75% of the executive's long-term incentive, are based on the achievement of pre-established performance measures. Payment of time-vesting restricted stock unit shares, which represent 25% of the executive's long-term incentive, are based on retention of the executive at the end of the three-year period. All long-term incentives are paid through shares of common stock which encourages stock ownership by our executives.
- ☑ **Balanced Mix of Pay Components** - The target compensation mix represents a balance of annual cash and long-term equity-based compensation.
- ☑ **Mix of Financial Goals** - Use of a mixture of financial goals to measure performance prevents overemphasis on a single metric.
- ☑ **Diversity, Equity and Inclusion Modifier** - The 2022 annual cash incentive included a diversity, equity and inclusion (DEI) modifier aimed at furthering the company's diversity, equity and inclusion initiatives. The DEI modifier increases or decreases the annual incentive up to 5% based on the compensation committee's consideration of the company's progress on DEI initiatives.
- ☑ **Annual Compensation Risk Analysis** - Risks related to our compensation programs are regularly analyzed through an annual compensation risk assessment.
- ☑ **Stock Ownership and Retention Requirements** - Executive officers are required to own, within five years of appointment or promotion, company common stock equal to a multiple of their base salary. Our CEO is required to own stock equal to six times his base salary, and the other named executive officers are required to own stock equal to three times their base salary. The executive officers also must retain at least 50% of the net after-tax shares of stock vested through the long-term incentive plan for the earlier of two years or until termination of employment. Net performance shares must also be held until share ownership requirements are met.
- ☑ **Clawback Policy** - If the company's audited financial statements are restated due to any material noncompliance with the financial reporting requirements under the securities laws, the compensation committee may, or shall if required, demand repayment of some or all incentives paid to our executive officers within the last three years.

What We Do Not Do

- ☒ **Stock Options** - The company does not use stock options as a form of incentive compensation.
- ☒ **Employment Agreements** - Executives do not, in the normal course, have employment agreements entitling them to specific payments upon termination or a change of control of the company.
- ☒ **Perquisites** - Executives do not receive perquisites that materially differ from those available to employees in general.
- ☒ **Hedge Stock** - Executives are not allowed to hedge company securities.
- ☒ **Pledge Stock** - Executives are not allowed to pledge company securities in margin accounts or as collateral for loans.
- ☒ **No Dividends or Dividend Equivalents on Unvested Shares** - We do not provide for payment of dividends or dividend equivalents on unvested share awards.
- ☒ **Tax Gross-Ups** - Executives do not receive tax gross-ups on their compensation.

Sustainability Highlights

MDU Resources is an essential services infrastructure company and manages its business with a long-term view toward sustainable operations, focusing on how economic, environmental, and social impacts help the corporation continue Building a Strong America®. We integrate sustainability efforts into our business strategy because these efforts directly affect long-term business viability and profitability. Our focus on sustainability helps ensure we are a good corporate citizen while creating opportunities to increase revenues and profitability, create a competitive advantage, and attract a skilled and diverse workforce. We have invested significantly more time and resources into our environmental, social and governance efforts in the past several years. Highlights of our enhanced efforts and achievements in the past year are set forth below. For the company's complete outline of environmental, governance and social responsibilities, see our Sustainability Report. The information provided in the Sustainability Report is not part of this Proxy Statement and is not incorporated by reference as part of this Proxy Statement.

Reporting Frameworks

To better serve our investors and other stakeholders, we report environmental, social, governance, and sustainability (ESG/sustainability) metrics relevant and important to our operations in the frameworks that provide our stakeholders more uniform and transparent data and information, allowing for comparison with our peers and other companies operating in our industries. For our applicable industries, we report ESG/sustainability metrics using frameworks developed by the Sustainability Accounting Standards Board (SASB), the reporting templates developed by the Edison Electric Institute (EEI) and the American Gas Association (AGA), and we continue to incorporate guidance from the Task Force on Climate-Related Financial Disclosures (TCFD) into our reporting as summarized below:

Reporting Frameworks	Business Segment
SASB	Construction Materials and Contracting
SASB	Construction Services
AGA	Pipeline
EEI / AGA	Electric and Natural Gas Utilities
TCFD	We continue to enhance and expand our disclosure of the company's governance, strategy, risk management, and metrics and targets related to climate risk in accordance with guidance from the TCFD.

Governance of Environmental and Social Responsibility

MDU Resources is committed to strong corporate governance practices in all areas, including governance of environmental and social responsibility. For more information on the company's governance practices and policies, see the "Corporate Governance" section in this Proxy Statement. Below is an overview of our governance practices related to the oversight of environmental and social responsibility:

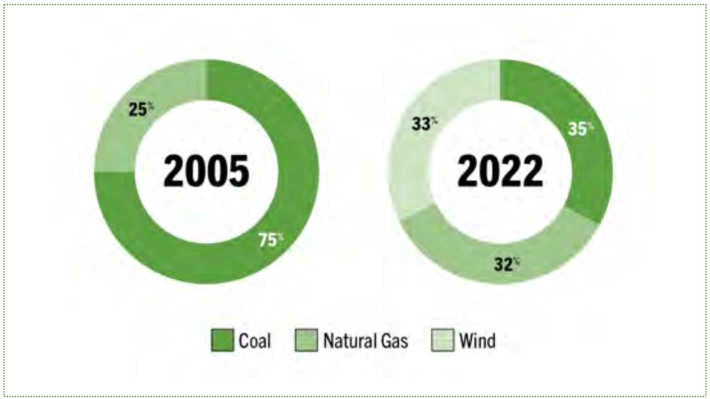
Board of Directors	The **board of directors** is ultimately responsible for oversight responsibility with respect to environmental, health, safety, and other social sustainability matters applicable to the company.
Environmental and Sustainability Committee of the Board	The **environmental and sustainability committee** is a standing committee of the board and meets quarterly in conjunction with the regular board meetings. The committee assists the board in fulfilling its oversight responsibilities with respect to environmental, social, and other sustainability matters, including climate change risks and opportunities, health, safety, and other social sustainability matters.
Management Policy Committee	The **management policy committee** is comprised of the business unit presidents and senior company officers. The committee meets monthly, or more frequently as warranted, and is responsible for the management of risks and pursuit of opportunities related to environmental and social sustainability matters, including climate change, health, safety, and other social sustainability matters.
Executive Sustainability Committee	The **executive sustainability committee** is comprised of corporate and business unit senior executives and supports execution of the company's environmental and sustainability strategy and establishes, maintains, and enhances the processes, procedures, and controls for the company's environmental and sustainability disclosures.

Environmental Stewardship

- **Carbon Footprint.** While we have reported carbon emissions from our electric generating fleet for many years, as of January 1, 2022, we began tracking our Scope 1 and Scope 2 carbon emissions across the company to establish our corporatewide baseline of emissions. For more information on anticipated future reporting and emission reduction goals, see our Sustainability Report.

- **Retirement of Coal Facilities.** We have ceased operating all wholly owned coal-fired generation facilities, with Units 1 and 2 at Heskett Station near Mandan, North Dakota, being retired in early 2022 as more economical options exist to supply energy for our customers. These retirements will further reduce our greenhouse gas emissions intensity as we progress toward our reduction target of 45% by 2030, compared to 2005 levels, from owned generating facilities. During 2022, Montana-Dakota Utilities Co. began construction of a new 88-MW simple-cycle natural gas-fired combustion peaking turbine unit at the existing Heskett Station.

- **Generation Capacity by Fuel Type.** Montana-Dakota Utilities Co.'s historical and year-end 2022 total generating capacity by fuel type shows the shift from coal to more renewable resources as follows:



- **Methane Emissions.** We have established a near-term methane emissions intensity reduction target of 25% by 2030, compared to our 2020 rate, at our natural gas pipeline business. In addition WBI Energy, Inc. joined the One Nation's Energy Future Coalition (ONE Future Coalition) in 2022. The ONE Future Coalition is a group of more than 55 natural gas companies working together to voluntarily reduce methane emissions across the natural gas value chain to 1% or less by 2025. It is comprised of some of the largest natural gas production, gathering and boosting, processing, transmission and storage, and distribution companies in the U.S.

- **Climate Scenario Analysis.** The company completed a climate scenario analysis in 2021 for its electric generation operations following guidance from the TCFD.

- **Climate-Related Risks and Opportunities.** In 2022, according to TCFD guidance, our businesses enhanced their understanding and identification of our climate-related risks and opportunities over the short, medium and long term. This exercise helps us strategically prepare to mitigate potential risks and optimize opportunities. Examples of some of the key items identified include:
  - Both risks and opportunities from increased frequency and duration of severe weather events. For instance, property and facility damage is a risk that can result from inclement weather. Weather-related damage also presents an opportunity, however, as our construction businesses can provide infrastructure repair and reconstruction services.
  - Both risks and opportunities from efforts to decarbonize electric generation sources. This requires investment in, partnership with, and construction of renewable energy sources, such as wind and solar generation and biogas producers. It is also expected that natural gas will be needed as a backup generation fuel source for periods when renewable sources are unavailable.
  - Changes in public policy to address climate change could create risks and opportunities as demand for the company's products and services could be impacted, costs could escalate, and modifications and additional investment in our regulated energy delivery business may be necessary to ensure reliability of service to customers.

  We intend to include our full risks and opportunities assessment in the company's 2022 Sustainability Report, which is expected to be available in the third quarter of 2023.

- **Environmental Recognitions.**
  - Intermountain Gas Company received the 2022 ENERGY STAR® Market Leader Award for its efforts to promote energy-efficient residential construction and help homebuyers and residents experience the quality, comfort, and value that come with living in an ENERGY STAR-certified home or apartment.

- **Renewable Diesel**. In 2021, a number of Knife River Corporation's west coast operations used renewable diesel fuel in their on-road and off-road fleets. Engine performance, engine maintenance, and fuel efficiency results were positive during the pilot, and Knife River Corporation is beginning to utilize renewable diesel in more locations where feasible. In Oregon, Knife River Corporation has successfully piloted the use of renewable diesel fuel in its on-road and off-road fleet vehicles, reducing GHG emissions and improving fuel efficiency, and expects that greater than 90% of its 2023 diesel consumption in Oregon (and approximately 18% of its company-wide diesel consumption) will be renewable diesel.

- **Environmental-Related Investments.** Knife River Corporation has invested in Blue Planet Systems Corporation to pursue the use of synthetic aggregates in ready-mix concrete. Blue Planet Systems Corporation is testing methods of creating synthetic limestone by using carbon dioxide captured from existing sources. The synthetic limestone could then be used as a component of concrete. In addition to sequestering carbon dioxide through this process, the use of synthetic limestone could also prolong the life of natural aggregate sources.

- **Warm-Mix Asphalt.** Knife River Corporation produces and places warm-mix asphalt in applications where warm-mix asphalt is allowed. Warm-mix asphalt is produced at cooler temperatures than traditional hot-mix asphalt methods, which reduces the amount of fuel needed in the production process, thereby reducing emissions and fumes.

- **Recycling.** Knife River Corporation continues its long-standing practice of recycling and reusing building materials. Recycling conserves natural resources, uses less energy, reduces waste disposal at local landfills, and ultimately costs less for our customers. Knife River Corporation recycles or reuses asphalt pavement, pre-consumer asphalt shingles, refined fuel oil, demolition concrete, returned concrete at ready-mix plants, fly ash, slag, silica fume and other cement-replacement materials, and dimension stone reject material.

- **Energy Efficiency.** Our utility companies actively pursue programs to increase energy efficiency and conservation for electric and natural gas customers. This includes partnering with local community action agencies in providing low-income assistance for utility customers and offering residential and commercial incentive programs that promote installation of energy-efficient electric and natural gas equipment.

- **Renewable Natural Gas.** Our utility companies are pursuing additional opportunities to provide renewable natural gas to customers. We have produced renewable natural gas from the Billings, Montana, landfill for customer use since 2010. In Idaho, three dairy digesters have been adding renewable natural gas to our system for customer use since 2020.

Social Responsibility

MDU Resources knows that it operates at the discretion of various stakeholders, including customers, stockholders, employees, regulators, lawmakers, and the communities where we do business. It is these stakeholders who allow us to conduct our business and are vital to our success. MDU Resources remains committed to maintaining the trust of these stakeholders by operating with integrity and being a good corporate citizen. Below are highlights of our social responsibility programs relating to our employees, stockholders, communities, and customers.

- **Our Employees and Human Capital Management.** At the core of Building a Strong America® is building a strong workforce. At MDU Resources, this means building a strong team of employees with a focus on integrity and safety and a commitment to diversity, equity, and inclusion. Our team included 14,929 employees located in 44 states plus Washington D.C. as of December 31, 2022. Our number of employees peaked in the third quarter at just over 16,800. Our Employer Information Report EEO-1 is available on our website at www.mdu.com/careers. The information on our website is not part of this Proxy Statement and is not incorporated by reference into this Proxy Statement.

  - **Diversity, Equity, and Inclusion.** MDU Resources is committed to an inclusive environment that respects the differences and embraces the strengths of our diverse employees. Essential to the company's success is its ability to attract, retain, and engage the best people from a broad range of backgrounds and build an inclusive culture where all employees feel valued and contribute their best. To aid in the company's commitment to an inclusive environment, each business segment has a diversity officer who serves as a conduit for diversity-related issues and provides a voice for all employees. The company requires employees to participate in training on the company's code of conduct and additional courses focusing on diversity, effective leadership, equal employment opportunity, workplace harassment, respect, and unconscious bias. The company has three strategic goals related to diversity:

    Diversity.
    Equity. Inclusion.

    - Enhance collaboration efforts through cooperation and sharing of best practices to create new ways of meeting employee, customer, and stockholder needs;
    - Maintain a culture of integrity and safety by ensuring employees understand these essential values, which are part of the company's vision statement; and
    - Increase productivity and profitability through the creation of a work environment that values all perspectives and methods of accomplishing work.

☐ **CEO Action for Diversity and Inclusion Pledge**. In March 2022, MDU Resources' chief executive officer signed the CEO Action for Diversity and Inclusion Pledge, joining more than 2,000 chief executive officers in signing and committing to four goals to be a catalyst for further conversations and action around diversity and inclusion in the workplace. The four goals include:

- Cultivating environments that support open dialogue on complex and often-difficult conversations.
- Implementing and expanding unconscious bias education and training.
- Sharing best-practice diversity, equity and inclusion programs and initiatives.
- Engaging boards of directors when developing and evaluating diversity, equity and inclusion strategies.

☐ **Executive Compensation and Diversity, Equity, and Inclusion**. In February 2022, the board of directors approved a performance modifier for the 2022 annual incentive award program for executive officers based upon the company's achievement of certain measures to attract, retain, and develop a diverse and inclusive workforce. The DEI modifier includes a focus on representation of diverse employees in executive succession plans, outreach efforts to attract diverse candidates for open positions at the company, implementing enhanced diversity, equity, and inclusion training and mentoring for new employees, and development of enhanced employee data dashboards to further support the company's efforts to attract, retain, and develop a diverse and inclusive workforce. For more information on the DEI modifier and the results for 2022, please refer to the "2022 Compensation for Our Named Executive Officers" section in the "Compensation Discussion and Analysis."

☐ **Building People.** Building a strong workforce begins with employee recruitment. The company uses a variety of means to recruit new employees for open positions, including posting on the company's website, employee referrals, union workforce, direct recruitment, advertising, social media, career fairs, partnerships with colleges and technical schools, job service organizations, and associations connected with a variety of professions. The company also utilizes internship programs to introduce individuals to the company's business operations and provide a possible source of future employees. Building a strong workforce also requires developing employees in their current positions and for future advancement. The company provides opportunities for advancement through job mobility, succession planning, and promotions both within and between business segments. The company provides employees the opportunity to further develop and grow through various forms of training, mentorship programs, and internship programs.

☐ **Knife River Training Center**. While labor challenges continue to impact many construction companies, Knife River Corporation is actively engaged in attracting, training and retaining the next generation of construction-industry employees. In February 2022, the company completed a state-of-the-art training center on a 230-acre tract of property in the Pacific Northwest, featuring an 80,000 square-foot heated indoor arena for training on trucks and heavy equipment and an attached 16,000 square-foot classroom and conference room facility. The center is used company-wide to enhance the skills of current employees and to recruit and teach skills to new employees through both classroom education and hands-on experience. It also is used by Knife River Corporation's customers and industry peers, who send employees to the center to take courses on heavy equipment, truck driving, leadership development, facilitator training, safety training and more.

In 2022, the center hosted approximately 4,500 individuals for various trainings, classes, meetings and events. The facility plays a critical role in Knife River Corporation's workforce remaining sustainable and contributes to showcasing construction as a career of choice.

Knife River Corporation's outreach efforts to market the training center have included interfacing with historically underrepresented groups, and the company has partnered with the National Association of Minority Contractors to provide scholarships for training to qualifying employees of minority-owned businesses.

☐ The Knife River Corporation training center received the 2022 Risk Management Excellence Award presented by Liberty Mutual Insurance Company. The award recognizes outstanding employee health and safety achievement related to an industry-leading, state-of-the-art training center leading to better training and lowering risks to the employees and general public. Liberty Mutual Insurance Company has granted this award less than 20 times in their 100-year history.

☐ **Safety.** The company is committed to safety and health in the workplace. To ensure safe work environments, the company provides training, adequate resources, and appropriate follow-up on any unsafe conditions or actions. The company has policies and training that support safety in the workplace, including training on safety matters through classroom and toolbox meetings on job sites. To facilitate a strong safety culture, MDU Resources has a safety leadership council that aims to identify and adopt best management practices to aid in the prevention of occupation injuries and illness.

  - **Ethics Reporting**. MDU Resources' employees are encouraged to ask questions or report concerns to their supervisor. If employees have concerns that something may be unethical or illegal within the company, they are encouraged to report their concerns to a human resources representative, a company executive, or their compliance officer. For those wishing to remain anonymous, MDU Resources also has an anonymous reporting hotline. Employees, customers, and other stakeholders can report confidentially and anonymously through this third-party telephone and internet-based reporting system any concerns about possible unethical or illegal activities. Reports are carefully considered and investigated. Summaries of the reports and investigative results are provided to the audit committee of the board of directors.

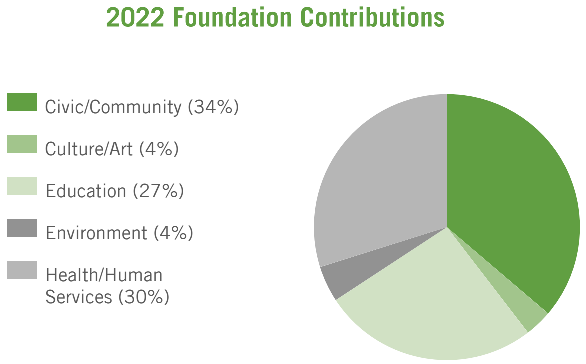
- **Vendor Code of Conduct.** MDU Resources has a Vendor Code of Conduct that outlines our expectations of vendors, including ethical business practices, workplace safety, environmental stewardship and compliance with applicable laws and regulations.

- **Our Stockholders.** MDU Resources' management is committed to acting in the best interest of the corporation, protecting its assets, and serving the long-term interests of the company's stockholders. This includes protecting our tangible interests, such as property and equipment, as well as intangible assets, such as our reputation, information, and intellectual property. For information on our stockholder outreach program, see "Stockholder Engagement" in the section entitled "Corporate Governance" of this Proxy Statement.

- **Our Communities.**

  - **Community Health and Safety.** The pipeline and natural gas utility companies' pipeline integrity and safety management programs provide guidelines for the continual evaluation of their pipeline systems using risk-based criteria that allows our companies to take proactive measures to ensure public safety and protect the environment. In addition, the pipeline safety management systems are comprehensive, continuous improvement programs designed to promote a culture dedicated to employee and public safety and environmental protection while maintaining the safety and reliability of our natural gas distribution, transmission, and storage facilities.

  - **Charitable Giving.** MDU Resources is proud of its record of supporting qualified organizations that enhance quality of life. Our philanthropic goal is to be a "neighbor of choice." The MDU Resources Foundation was incorporated in 1983 to support the corporation's charitable efforts and has contributed more than $42 million to worthwhile organizations. In 2022, the MDU Resources Foundation contributed $2.3 million to charitable organizations. In addition to contributions through the MDU Resources Foundation, our business segments and companies regularly make charitable donations and in-kind donations to the communities where they do business.



  - **Volunteerism.** We encourage and support community volunteerism by our employees. The MDU Resources Foundation contributes a $750 grant to an eligible nonprofit organization after an employee or group of employees volunteer a minimum of 25 hours to the organization during non-company hours in a calendar year. Eligible organizations are local 501(c) nonprofit organizations providing services in categories of civic and community activities, culture and arts, education, environment, and health and human services. In 2022, the foundation granted $98,000 under this program, matching over 6,929 employee volunteer hours.

  - **Education.** We encourage support of educational institutions by all employees. The MDU Resources Foundation matches contributions up to $750 to educational institutions by employees. In addition, the MDU Resources Foundation maintains two separate scholarship programs, which includes funding scholarship programs at institutions of higher education and scholarships for employee family members.

- **Our Customers.**

☐ Our utility companies consistently rank high in customer satisfaction. In the J.D. Power 2022 Gas Utility Residential Customer Satisfaction Study$^{\text{SM}}$, Cascade Natural Gas Corporation ranked first, Intermountain Gas Company third, and Montana-Dakota Utilities Co. sixth among mid-size natural gas utilities in the west region.

☐ Montana-Dakota Utilities Co. was announced as an Edison Electric Institute (EEI) Emergency Response Award recipient. Presented to EEI member companies, the Emergency Response Awards recognize recovery and assistance efforts of electric companies following service disruptions caused by extreme weather or other natural events.

The company believes in corporate social responsibility and the fundamental commitment to its stakeholders: customers, employees, suppliers, communities, and stockholders. With the company's origin and rich history in providing electric and natural gas utility service to rural communities in North Dakota, South Dakota, Montana, and Wyoming, our utility companies have long operated under the motto "In the Community to Serve®." Infrastructure is our business and we define our purpose as "Building a Strong America®" in recognition of our mission to deliver value to our stakeholders.

MDU RESOURCES
GROUP, INC.

Building a Strong America®

BOARD OF DIRECTORS

ITEM 1. ELECTION OF DIRECTORS

The board currently consists of ten directors, all of whom are standing for election to the board at the 2023 annual meeting to hold office until the 2024 annual meeting and until their successors are duly elected and qualified.

The board has affirmatively determined all the director nominees, other than David L. Goodin, our president and chief executive officer, are independent in accordance with New York Stock Exchange (NYSE) rules, our governance guidelines, and our bylaws.

Our bylaws provide for a majority voting standard for the election of directors. See "Additional Information - Majority Voting" below for further detail.

Each of the director nominees has consented to be named in this Proxy Statement and to serve as a director, if elected. We do not know of any reason why any nominee would be unable or unwilling to serve as a director, if elected. If a nominee becomes unable to serve or will not serve, proxies may be voted for the election of such other person nominated by the board as a substitute or the board may choose to reduce the number of directors.

Information about each director nominee's share ownership is presented under "Security Ownership."

The shares represented by the proxies received will be voted for the election of each of the ten nominees named below unless you indicate in the proxy that your vote should be cast against any or all the director nominees or that you abstain from voting. Each nominee elected as a director will continue in office until his or her successor has been duly elected and qualified or until the earliest of his or her resignation, retirement, or death.

The ten nominees for election to the board at the 2023 annual meeting, all proposed by the board upon recommendation of the nominating and governance committee, are listed below with brief biographies. The nominees' ages are current as of December 31, 2022.

On January 24, 2023, the company entered into the Cooperation Agreement with Corvex Management LP, pursuant to which Corvex Management LP partner, James H. Gemmel, was appointed as a non-voting board observer and, subject to FERC approval, to the board of directors. For further details on the Cooperation Agreement, see the section entitled "Corporate Governance."

On August 4, 2022, the company announced its intention to separate its indirect, wholly owned subsidiary, Knife River Corporation, from the company. The separation is anticipated to result in two independent, publicly traded companies. If the spin-off transaction is completed, the company expects that one or more of its directors may become directors of Knife River Corporation, in which case they will resign from the company's board of directors at such time.

The board of directors recommends that the stockholders vote FOR the election of each nominee.

Director Nominees

German Carmona Alvarez
Age 54

Independent Director Since 2022
Compensation Committee
Nominating and Governance Committee

Key Contributions to the Board: With 15 years of global experience in the building materials industry, Mr. Carmona Alvarez brings broad industry expertise to the board. Mr. Carmona Alvarez also contributes experience and expertise in human capital management, digital and information technology, finance, and mergers and acquisitions.

Career Highlights

- Global president of applied intelligence of the consulting and engineering company Wood PLC, Aberdeen, United Kingdom, since 2021. Director of Wood PLC USA, Houston, Texas, the United States affiliate of Wood PLC, since 2022.
- Senior vice-president and global digital practice leader of NEORIS, a technology and digital strategy consulting firm with presence in 27 countries focusing on the design strategy and execution of agile digital transformation programs, from March 2019 to July 2021.
- Executive vice-president finance, information technology and shared services of CEMEX Inc., a global building materials company from 2016 to 2019; senior vice president of continuous improvement and commercial strategy from 2014 to 2016; senior vice president of aggregates and mining resources from 2012 to 2014; global vice president of organization, compensation and benefits from 2009-2012; global vice president of human resources planning and development from 2006 to 2009; corporate vice president of human capital from 2004 to 2006.
- Senior principal of strategy and transformation of The Boston Consulting Group, a general management consulting firm that practices in business strategy, from 2000 to 2004.

Other Leadership Experience

- Former board chair of Strata.ai, a strategy and venture building firm focused on decision science, artificial intelligence and extended reality, from 2020 to 2022.
- Former board of trustees of ITESM/Tec Milenio, a private institution of higher education, from 2010 to 2017.

Thomas Everist
Age 73

Independent Director Since 1995
Compensation Committee
Nominating and Governance Committee

Key Contributions to the Board: With a 44-year career in the construction materials and mining industry, Mr. Everist brings critical knowledge of the construction materials and contracting industry to the board. Mr. Everist also contributes strong business leadership and management capabilities and insights through his role as president and chair of his companies for over 35 years. His experience on the board of another public company further enhances his contributions to the board.

Career Highlights

- President and chair of The Everist Company, Sioux Falls, South Dakota, an investment and land development company, since April 2002. Prior to January 2017, The Everist Company was engaged in aggregate, concrete, and asphalt production.
- Managing member of South Maryland Creek Ranch, LLC, a land development company, since June 2006; president of SMCR, Inc., an investment company, since June 2006; and managing member of MCR Builders, LLC, which provides residential building services to South Maryland Creek Ranch, LLC, since November 2014.
- Director and chair of Everist Genomics, Inc., Ann Arbor, Michigan, a company that provided solutions for personalized medicines, from May 2002 to July 2021, and chief executive officer from August 2012 to December 2012.
- President and chair of L.G. Everist, Inc., Sioux Falls, South Dakota, an aggregate production company, from 1987 to April 2002.

Other Leadership Experience

- Director of publicly traded Raven Industries, Inc., Sioux Falls, South Dakota, a general manufacturer of electronics, flow controls, and engineered films, from May 1996 to December 2021, and chair from April 2009 to May 2017.
- Director and compensation committee chair of Bell, Inc., Sioux Falls, South Dakota, a manufacturer of folding cartons and packages, from April 2011 to July 2022.
- Director and audit committee chair of Showplace Wood Products, Inc., Sioux Falls, South Dakota, a custom cabinets manufacturer, since January 2000.
- Director of Angiologix Inc., Mountain View, California, a medical diagnostic device company, from July 2010 through October 2011 when it was acquired by Everist Genomics, Inc.
- Member of the South Dakota Investment Council, the state agency responsible for investing state funds, from July 2001 to June 2006.

Karen B. Fagg

Age 69

Independent Director Since 2005
Compensation Committee
Environmental and Sustainability Committee

Key Contributions to the Board: Through her management experience and knowledge in the fields of engineering, environment, and energy resource development, including four years as director of the Montana Department of Natural Resources and Conservation and over eight years as president, chief executive officer, and chair of her own engineering and environmental services company, as well as her service on a number of Montana state and community boards, Ms. Fagg contributes experience in responsible natural resource development with an informed perspective of the construction, engineering, and energy industries.

Career Highlights

- Vice president of DOWL LLC, dba DOWL HKM, an engineering and design firm, from April 2008 until her retirement in December 2011.
- President of HKM Engineering, Inc., Billings, Montana, an engineering and environmental services firm, from April 1995 to June 2000, and chair, chief executive officer, and majority owner from June 2000 through March 2008. HKM Engineering, Inc. merged with DOWL LLC in April 2008.
- Employed with MSE, Inc., Butte, Montana, an energy research and development company, from 1976 through 1988, and vice president of operations and corporate development director from 1993 to April 1995.
- Director of the Montana Department of Natural Resources and Conservation, the state agency charged with promoting stewardship of Montana’s water, soil, energy, and rangeland resources; and administering several grant and loan programs, from 1989 through 1992.

Other Leadership Experience

- Director and member of the quality committee of the Intermountain Health Peaks Region Board, since January 2023.
- Director and finance committee chair of the Montana State Fund, the state’s largest workers’ compensation insurance company, from March 2021 to present; Director of SCL Health Montana Regional Board from January 2020 to present, including a term as chair; and member of Carroll College Board of Trustees from 2005 through 2010, and from August 2019 through June 2022.
- Former member of several regional, state, and community boards, including director of St. Vincent’s Healthcare from October 2003 to October 2009 and January 2016 through January 2020, including a term as chair; director of the Billings Catholic Schools Board from December 2011 through December 2018, including a term as chair; the First Interstate BancSystem Foundation from June 2013 to 2016; the Montana Justice Foundation from 2013 to 2015; Montana Board of Investments from 2002 through 2006; Montana State University’s Advanced Technology Park from 2001 to 2005; and Deaconess Billings Clinic Health System from 1994 to 2002.

David L. Goodin

Age 61

Director Since 2013
President and Chief Executive Officer

Key Contributions to the Board: Serving as president and chief executive officer of MDU Resources Group, Inc. since 2013, Mr. Goodin is the only officer of the company that serves on our board. With 30 years of operating and leadership positions with our utility operations and ten years in his current position, he brings utility industry experience to the board as well as extensive knowledge of our company and its business operations. He contributes valuable insight into management’s views and perspectives and the day-to-day operations of the company.

Career Highlights

- President and chief executive officer and a director of the company since January 4, 2013.
- Prior to January 4, 2013, served as chief executive officer and president of Intermountain Gas Company, Cascade Natural Gas Corporation, Montana-Dakota Utilities Co., and Great Plains Natural Gas Co.
- Began his career in 1983 at Montana-Dakota Utilities Co. as a division electrical engineer and served in positions of increasing responsibility until 2007 when he was named president of Cascade Natural Gas Corporation; positions included division electric superintendent, electric systems manager, vice president-operations, and executive vice president-operations and acquisitions.

Other Leadership Experience

- Member of the U.S. Bancorp Western North Dakota Advisory Board since January 2013.
- Director of Sanford Bismarck, an integrated health system dedicated to the work of health and healing, and Sanford Living Center, from January 2011 through December 2021.
- Board member of the BSC Innovations Foundation, an extension of Bismarck State College providing curriculum to Saudi Arabia industries, since August 1, 2018.
- Current vice chair of the North Dakota State University (NDSU) Foundation and Alumni Association, a foundation with a mission of cultivating a culture of philanthropy through educating students, engaging alumni and supporters, and growing future leaders.
- Former board member of numerous industry associations, including the American Gas Association, the Edison Electric Institute, the North Central Electric Association, the Midwest ENERGY Association, and the North Dakota Lignite Energy Council.

Dennis W. Johnson

Age 73

Independent Director Since 2001
Chair of the Board

Key Contributions to the Board: With over 48 years of experience in business management, manufacturing, and finance, holding positions as chair, president, and chief executive officer of TMI Group Incorporated for 41 years, as well as his prior service as a director of the Federal Reserve Bank of Minneapolis, Mr. Johnson brings operational, management, strategic planning, specialty contracting, and financial knowledge and insight to the board. Mr. Johnson also contributes significant knowledge of local, state, and regional issues involving North Dakota, the state where we are headquartered and have significant operations, resulting from his service on several state and local organizations.

Career Highlights

- Chair of the board of the company effective May 8, 2019; and vice chair of the board from February 15, 2018 to May 8, 2019.
- Chair, president, and chief executive officer of TMI Group Incorporated as well as its two wholly owned subsidiary companies, TMI Corporation and TMI Transport Corporation, manufacturers of casework and architectural woodwork in Dickinson, North Dakota; employed since 1974 and serving as president or chief executive officer since 1982.

Other Leadership Experience

- Member of the Bank of North Dakota Advisory Board of Directors since August 2017, currently serving as vice chair.
- President of the Dickinson City Commission from July 2000 through October 2015.
- Director of the Federal Reserve Bank of Minneapolis from 1993 through 1998.
- Served on numerous industry, state, and community boards, including the North Dakota Workforce Development Council (chair); the Decorative Laminate Products Association; the North Dakota Technology Corporation; and the business advisory council of the Steffes Corporation, a metal manufacturing and engineering firm.
- Served on North Dakota Governor Sinner's Education Action Commission; the North Dakota Job Service Advisory Council; the North Dakota State University President's Advisory Council; North Dakota Governor Schafer's Transition Team; and chaired North Dakota Governor Hoeven's Transition Team.

Patricia L. Moss

Age 69

Independent Director Since 2003
Compensation Committee
Environmental and Sustainability Committee

Other Current Public Boards:
--First Interstate BancSystem, Inc.
--Aquila Group of Funds

Key Contributions to the Board: With substantial experience in the finance and banking industry, including service on the boards of public banking and investment companies, Ms. Moss contributes broad knowledge of finance, business development, human resources, and compliance oversight, as well as public company governance, to the board. Through her business experience and knowledge of the Pacific Northwest, Ms. Moss also provides insight on state, local, and regional economic and political issues where a significant portion of our operations and the largest number of our employees are located.

Career Highlights

- President and chief executive officer of Cascade Bancorp, a financial holding company, Bend, Oregon, from 1998 to January 3, 2012; chief executive officer of Cascade Bancorp's principal subsidiary, Bank of the Cascades, from 1998 to January 3, 2012, serving also as president from 1998 to 2003; and chief operating officer, chief financial officer and secretary of Cascade Bancorp from 1987 to 1998.

Other Leadership Experience

- Member of the Oregon Investment Council, which oversees the investment and allocation of all state of Oregon trust funds, from December 2018 to March 2021.
- Director of First Interstate BancSystem, Inc., since May 30, 2017.
- Director of Cascade Bancorp and Bank of the Cascades from 1993, and vice chair from January 3, 2012 until May 30, 2017 when Cascade Bancorp merged into First Interstate BancSystem, Inc., and became First Interstate Bank.
- Chair of the Bank of the Cascades Foundation Inc. from 2014 to July 31, 2018; co-chair of the Oregon Growth Board, a state board created to improve access to capital and create private-public partnerships, from May 2012 through December 2018; and a member of the Board of Trustees for the Aquila Group of Funds, whose core business is mutual fund management and provision of investment strategies to fund shareholders, from January 2002 to May 2005 (one fund) and from June 2015 to present (currently three funds).
- Former director of the Oregon Investment Fund Advisory Council, a state-sponsored program to encourage the growth of small businesses in Oregon; the Oregon Business Council, with a mission to mobilize business leaders to contribute to Oregon's quality of life and economic prosperity; the North Pacific Group, Inc., a wholesale distributor of building materials, industrial, and hardwood products; and Clear Choice Health Plans Inc., a multi-state insurance company.

Dale S. Rosenthal

Age 66

Independent Director Since 2021
Audit Committee
Nominating and Governance Committee

Key Contributions to the Board: With 22 years of experience with an integrated construction company, serving in senior executive positions as strategic director, division president, and chief financial officer, Ms. Rosenthal contributes expertise in construction, alternative energy, real estate and infrastructure development, risk management, and corporate strategy. Ms. Rosenthal also brings public board experience with a regulated public utility company.

Career Highlights

- Strategic director of Clark Construction Group, LLC, a vertically integrated construction company headquartered in Bethesda, Maryland, from January 2017 to December 2017; division president of Clark Financial Services Group, leveraging Clark's core turnkey construction expertise into alternative energy development, from April 2008 to December 2016; chief financial officer and senior vice president of Clark Construction Group, LLC, from April 2000 to April 2008; and established a Clark subsidiary, Global Technologies Group, which developed and built data centers for early internet service providers. Ms. Rosenthal joined Clark Construction in 1996.
- Led financing teams for several tax-credit financed housing developers and was instrumental in identifying new sources of funding and innovative tax structures for complex transactions.

Other Leadership Experience

- Director of Washington Gas Light Company, formerly publicly traded and now a subsidiary of AltaGas Ltd., since October 2014, and chair of the audit committee from 2018 to 2022. Washington Gas is a regulated public utility company that sells and delivers natural gas in the District of Columbia and surrounding metropolitan areas.
- Board advisor of Langan Engineering & Environmental Services, a provider of an integrated mix of engineering and environmental consulting services in support of land development projects, corporate real estate portfolios, and the oil and gas industry, since March 2020.
- Member, Board of Trustees of Cornell University since June 2017, serving on the finance and building and properties committees.
- Director of Transurban Chesapeake LLC, a company that develops and operates toll roads in the Mid-Atlantic region, since August 2021, and chair of the audit committee since 2022.

Edward A. Ryan

Age 69

Independent Director Since 2018
Audit Committee
Nominating and Governance Committee

Key Contributions to the Board: As a former executive vice president and general counsel for a large public company with international operations, Mr. Ryan contributes expertise to the board in the areas of corporate governance, acquisitions, risk management, legal, compliance, and labor relations. Mr. Ryan also brings senior leadership, transactional, and public company experience.

Career Highlights

- Advisor to the chief executive officer and president of Marriott International from December 2017 to December 31, 2018.
- Executive vice president and general counsel of Marriott International from December 2006 to December 2017; senior vice president and associate general counsel from 1999 to November 2006; and assumed responsibility for all corporate transactions and corporate governance in 2005. Mr. Ryan joined Marriott International as assistant general counsel in May 1996.
- Private law practice from 1979 to 1996.

Other Leadership Experience

- Director of C&O Canal Trust, a non-profit partner of the Chesapeake & Ohio Canal National Historical Park, that works in conjunction with the National Park Service and local communities for park preservation highlighting the park's historical, natural and cultural heritage, while embracing the principles of diversity, equity, and inclusion in its work, since January 2022, and chair of the nominating and governance committee since January 2023.
- Director and finance committee member of Goodwill of Greater Washington, D.C., a non-profit organization whose mission is to transform lives and communities through education and employment, since January 2015, including a term as chair from January 2020 through December 2021, vice chair from January 2019 through December 2019, and chair of the finance committee from January 2018 through December 2019.
- Board advisor of Workbox Company, a startup company that provides collaborative coworking space and accelerator services, since January 2020.

David M. Sparby

Age 68

Independent Director Since 2018
Audit Committee
Environmental and Sustainability Committee

Key Contributions to the Board: With over 32 years of public utility management and leadership experience with a large public utility company, including positions as senior vice president and as chief financial officer, Mr. Sparby provides a broad understanding of the public utility and natural gas pipeline industries, including renewable energy expertise. His lengthy senior leadership experience with a public company also contributes to the board.

Career Highlights

- Senior vice president and group president, revenue, of Xcel Energy and president and chief executive officer of its subsidiary, NSP-Minnesota, from May 2013 until his retirement in December 2014; senior vice president and group president, from September 2011 to May 2013; chief financial officer from March 2009 to September 2011; and president and chief executive officer of NSP-Minnesota from 2008 to March 2009. He joined Xcel Energy, or its predecessor Northern States Power Company, as an attorney in 1982 and held positions of increasing responsibility.
- Attorney with the State of Minnesota, Office of Attorney General, from 1980 to 1982, during which period his responsibilities included representation of the Department of Public Service and the Minnesota Public Utilities Commission.

Other Leadership Experience

- Board of Trustees of Mitchell Hamline School of Law from July 2011 to July 2020.
- Board of Trustees of the College of St. Scholastica since July 2012, including service as chair from September 2020 to August 2022.

Chenxi Wang

Age 52

Independent Director Since 2019
Audit Committee
Environmental and Sustainability Committee

Key Contributions to the Board: Having significant technology and cybersecurity expertise through her management and leadership positions with several organizations, Ms. Wang contributes knowledge to the board on technology and cybersecurity issues. As the founder and managing general partner of a cybersecurity-focused venture fund, Ms. Wang also provides knowledge regarding capital markets and business development.

Career Highlights

- Founder and managing general partner of Rain Capital Fund, L.P., a cybersecurity-focused venture fund aiming to fund early-stage, transformative technology innovations in the security market with a goal of supporting women and minority entrepreneurs, since December 2017.
- Chief strategy officer at Twistlock, Inc., an automated and scalable cloud native cybersecurity platform, from August 2015 to March 2017.
- Vice president, cloud security & strategy of CipherCloud, LLC, a cloud security software company, from January 2015 to August 2015.
- Vice president of strategy of Intel Security, a company focused on developing proactive, proven security solutions and services that protect systems, networks, and mobile devices, from April 2013 to January 2015.
- Principal analyst and vice president of research at Forrester Research, a market research company that provides advice on existing and potential impact of technology, from January 2007 to April 2013.
- Assistant research professor and associate professor of computer engineering at Carnegie Mellon University from September 2001 through August 2007.
- Founder and director of Forte Group, an advocacy and education non-profit organization focusing on women in the cybersecurity industry, since November 2022.

Other Leadership Experience

- Technical Board of Advisors of Secure Code Warriors, a Sydney-based cybersecurity company, since June 2019.
- Board of directors of OWASP Global Foundation, a nonprofit global community that drives visibility and evolution in the safety and security of the world’s software, from January 2018 to December 2019, including a term as vice chair.
- Recipient of the 2019 Investor in Women Award by Women Tech Founders Foundation, an organization dedicated to advancing women in the technology industry.
- Board observer of ProjectDiscovery, Inc., an open-source software company that simplifies security operations for engineers and developers, since October 2022.
- Board observer of Stanza System, Inc., a company that specializes in site reliability engineering, since November 2022.

Additional Information - Majority Voting

A majority of votes cast is required to elect a director in an uncontested election. A majority of votes cast means the number of votes cast “for” a director’s election must exceed the number of votes cast “against” the director’s election. “Abstentions” and “broker non-votes” do not count as votes cast “for” or “against” the director’s election. In a contested election, which is an election in which the number of nominees for director exceeds the number of directors to be elected and which we do not anticipate, directors will be elected by a plurality of the votes cast.

Unless you specify otherwise when you submit your proxy, the proxies will vote your shares of common stock “for” all directors nominated by the board of directors. If a nominee becomes unavailable for any reason or if a vacancy should occur before the election, which we do not anticipate, the proxies will vote your shares in their discretion for another person nominated by the board.

Our policy on majority voting for directors contained in our corporate governance guidelines requires any proposed nominee for re-election as a director to tender to the board, prior to nomination, his or her irrevocable resignation from the board that will be effective, in an uncontested election of directors only, upon:

- receipt of a greater number of votes “against” than votes “for” election at our annual meeting of stockholders; and
- acceptance of such resignation by the board of directors.

Following certification of the stockholder vote, the nominating and governance committee will promptly recommend to the board whether or not to accept the tendered resignation. The board will act on the nominating and governance committee’s recommendation no later than 90 days following the date of the annual meeting.

Brokers may not vote your shares on the election of directors if you have not given your broker specific instructions on how to vote. Please be sure to give specific voting instructions to your broker so your vote can be counted.

Board Evaluations and Process for Selecting Directors

Our corporate governance guidelines require that the board, in coordination with the nominating and governance committee, annually reviews and evaluates the performance and functioning of the board and its committees.

The board evaluation process includes the following steps:

1 QUESTIONNAIRES

During 2022, each director completed an anonymous written questionnaire with the opportunity to provide comments. In addition, committee members completed a separate written questionnaire related to the operation of the respective committees.

2 BOARD SUMMARY AND FEEDBACK

The results of the written questionnaires were anonymously aggregated and provided to the board and each committee. Key strengths and opportunities for improvement of the board and each committee were reviewed and discussed in an executive session of the board in connection with this process.

3 BOARD SUCCESSION

As part of the annual board evaluation process, the nominating and governance committee evaluates our directors considering the current needs of the board and the company. This evaluation supports the nominating and governance committee's consideration of board succession and potential director recruitment throughout the year.

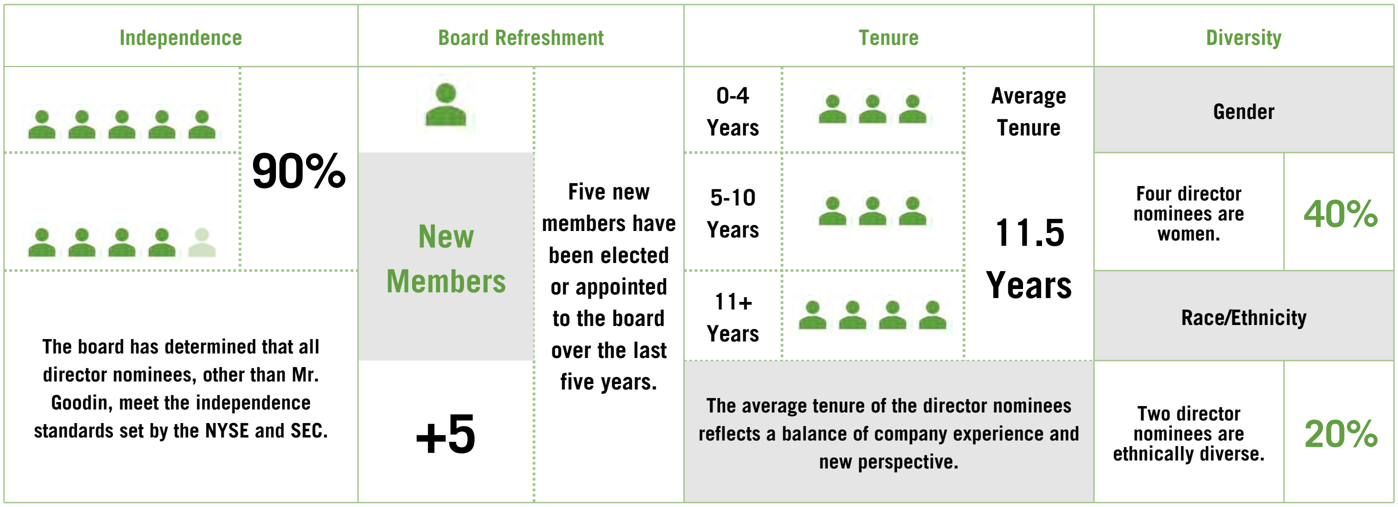
Director Qualifications, Skills, and Experience

Director nominees are chosen to serve on the board based on their qualifications, skills, and experience, as discussed in their biographies, and how those characteristics supplement the resources and talent on the board and serve the current needs of the board and the company. Our governance guidelines provide that directors are not eligible to be nominated or appointed to the board if they are 76 years or older at the time of the election or appointment. The board does not have term limits on the length of a director's service.

In making its nominations, the nominating and governance committee assesses each director nominee by a number of key characteristics, including character, success in a chosen field of endeavor, background in publicly traded companies, independence, and willingness to commit the time needed to satisfy the requirements of board and committee membership. Although the committee has no formal policy regarding diversity, the board is committed to having a diverse and broadly inclusive membership. In recommending director nominees, the committee considers diversity in gender, ethnic background, geographic area of residence, skills, and professional experience.

Board Skills and Diversity Matrix

	Carmona Alvarez	Everist	Fagg	Goodin	Johnson	Moss	Rosenthal	Ryan	Sparby	Wang
Skills & Expertise										
EXECUTIVE MANAGEMENT/PUBLIC COMPANY Served as CEO or other senior executive of an organization or as a director of another publicly traded company	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
ACCOUNTING/FINANCE Experience in the preparation and review of financial statements and financial reports	✓			✓	✓	✓	✓		✓	
CAPITAL MARKETS Experience overseeing company financings, investments, capital structures, and financial strategy	✓			✓	✓	✓	✓		✓	✓
INFORMATION TECHNOLOGY/CYBERSECURITY Oversight of or significant background working with information technology systems, data management, and/or cybersecurity risks	✓			✓						✓
RISK MANAGEMENT AND COMPLIANCE Regulatory and compliance expertise or experience in the identification, assessment, and mitigation of risks facing our company		✓	✓	✓	✓	✓	✓	✓	✓	✓
INDUSTRY EXPERIENCE Experience in our businesses and related industries, including public utilities, natural gas pipelines, construction, and aggregate mining	✓	✓		✓	✓		✓		✓	
LEGAL/CORPORATE GOVERNANCE Experience in dealing with complex legal and public company governance issues		✓		✓			✓	✓	✓	
HUMAN CAPITAL MANAGEMENT Experience in enterprise-wide human capital management and the development of talent, including overseeing diversity and inclusion efforts.	✓			✓		✓				
ENVIRONMENT AND SUSTAINABILITY Experience addressing environmental and sustainability issues relating to our businesses		✓	✓	✓			✓		✓	
GOVERNMENT/REGULATORY/PUBLIC AFFAIRS Background or experience in governmental regulations and public policy issues affecting our businesses			✓	✓	✓			✓	✓	
Gender/Age/Tenure										
Gender	M	M	F	M	M	F	F	M	M	F
Age	54	73	69	61	73	69	66	69	68	52
Tenure	1	28	18	10	22	20	2	5	5	4
Race/Ethnicity/Nationality										
African American/Black										
Alaskan Native or Native American										
Asian										✓
Hispanic/Latinx	✓									
Native Hawaiian or Pacific Islander										
White (not Hispanic or Latinx origins)		✓	✓	✓	✓	✓	✓	✓	✓	
Two or more Races or Ethnicities										
LGBTQ+										



Independence

90%

The board has determined that all director nominees, other than Mr. Goodin, meet the independence standards set by the NYSE and SEC.

Board Refreshment

New Members

+5

Five new members have been elected or appointed to the board over the last five years.

Tenure

0-4 Years

5-10 Years

11+ Years

Average Tenure

11.5 Years

The average tenure of the director nominees reflects a balance of company experience and new perspective.

Diversity

Gender

Four director nominees are women. 40%

Race/Ethnicity

Two director nominees are ethnically diverse. 20%

Board Composition and Refreshment

The nominating and governance committee is committed to ensuring that the board reflects a diversity of experience, skills, and backgrounds to serve the company's governance and strategic needs. In recognition of the company's commitment to diversity, the company was recognized in 2022 by 50/50 Women on Boards™ as a "3+" company for having three or more women on its board of directors.

Each of the nominees has been nominated for election to the board of directors upon recommendation by the nominating and governance committee and each has decided to stand for election.

In evaluating the needs of the board and the company, the nominating and governance committee focuses on identifying board candidates that will add gender and ethnic diversity along with relevant industry and leadership experience to the board, as well as a background and core competencies in the fields of technology, cybersecurity, and public company governance. To support this process, the nominating and governance committee engaged an independent global search firm in 2021 to assist with identifying, evaluating, and recruiting a diverse pool of potential director candidates, which led to the appointment of German Carmona Alvarez in 2022. Potential director nominees were brought to the attention of the nominating and governance committee by board members, management, advisory firms, and various organizations.

The nominating and governance committee continues to identify individuals as potential board of director candidates, particularly individuals with industry experience to support the company's strategy to create two pure-play companies of regulated energy delivery and construction materials, while pursuing organic growth opportunities and strategic acquisitions. The nominating and governance committee identified and recommended German Carmona Alvarez be appointment to the board in 2022 based on his expertise with human capital management, digital and information technology, finance, and mergers and acquisitions as well as his addition to the board's expertise and diversity.

By tenure, if the nominees are elected, the board will be comprised of three directors who have served from 0-4 years, three directors who have served from 5-10 years, and four directors who have served over 11 years. The nominating and governance committee believes this mix of director tenures provides a balance of experience and institutional knowledge with fresh perspectives. The nominating and governance committee also takes into consideration any written agreement for director nominations the company is a party to such as the Cooperation Agreement.

CORPORATE GOVERNANCE AND THE BOARD OF DIRECTORS

Director Independence

The board of directors has adopted guidelines on director independence that are included in our corporate governance guidelines. Our guidelines require that a substantial majority of the board consists of independent directors. In general, the guidelines require that an independent director must have no material relationship with the company directly or indirectly, except as a director. The board determines independence on the basis of the standards specified by the New York Stock Exchange (NYSE), the additional standards referenced in our corporate governance guidelines, and other facts and circumstances the board considers relevant. Based on its review, the board has determined that all directors, except for our chief executive officer Mr. Goodin, have no material relationship with the company and are independent.

In determining director independence, the board of directors reviewed and considered information about any transactions, relationships, and arrangements between the non-employee directors and their immediate family members and affiliated entities on the one hand, and the company and its affiliates on the other, and in particular the following transactions, relationships, and arrangements:

- *Charitable contributions by the company and the MDU Resources Foundation (Foundation) to nonprofit organizations where a director or immediate family member served as an officer or director of the organization.*
    - The company and the Foundation made charitable contributions to five such nonprofit organizations that collectively totaled $15,500. None of the contributions made to any of the nonprofit entities exceeded 2% of the relevant entity's consolidated gross revenues.
- *Business relationships with entities with which a director or director nominee is affiliated.*
    - Mr. Carmona Alvarez is currently the global president of applied intelligence of Wood PLC, a consulting and engineering company. The company paid an affiliate of Wood PLC approximately $6,475,000 in 2022 for services provided. The services were provided in the ordinary course of business and on substantially the same terms prevailing for comparable services from other consulting and engineering companies. Mr. Carmona Alvarez (i) played no role in the transactions between the company's subsidiaries and the Wood PLC entities; (ii) has no role, influence or oversight of the actual work of the Wood PLC entities with respect to the company; and (iii) did not receive any commission or have any financial interest in such work in a way that impacts the compensation he receives from Wood PLC. Mr. Carmona Alvarez had no role in securing or promoting the Wood PLC affiliated services.
    - Ms. Fagg was a member of the Board of Trustees for Carroll College. The company received payment for services provided to Carroll College in the amount of $736 in 2022. Ms. Fagg had no role in securing or promoting the services provided to Carroll College.

The board has also determined that all members of the audit, compensation, nominating and governance, and environmental and sustainability committees of the board are independent in accordance with our guidelines and applicable NYSE and Securities Exchange Act of 1934 rules, as applicable.

Oversight of Sustainability

We are an essential infrastructure company and manage our business with a long-term view toward sustainable operations, focusing on how economic, environmental, and social impacts help the company continue Building a Strong America®. We are committed to strong corporate governance in all areas, including governance of environmental and social responsibility.

Board of Directors. The board of directors is ultimately responsible for oversight with respect to environmental, health, safety, and other social sustainability matters applicable to the company.

Environmental and Sustainability Committee of the Board. In recognition of its responsibility for oversight with respect to environmental, health, safety, and other social sustainability matters, the board of directors in May 2019 formed the environmental and sustainability committee as a standing committee of the board with particular focus on our environmental, workplace health, safety, human capital, and other social sustainability programs and performance. The environmental and sustainability committee assists the board in fulfilling its oversight responsibilities with respect to environmental and social sustainability matters, including oversight and review of:

- **Employee, customer, and contractor safety;**
- **Climate change risks;**
- **Compliance with environmental, health, and safety laws;**
- **Human capital management;**
- **Integration of environmental and social principles into company strategy; and**
- **Significant public disclosures of environmental and sustainability matters.**

Additional oversight responsibilities of our environmental and sustainability committee are discussed on page 34.

Management Policy Committee. The company's management policy committee is comprised of the presidents of the business units and senior company officers. The management policy committee meets monthly, or more frequently as warranted, and is responsible for the management of risks and pursuit of opportunities related to environmental and social sustainability matters, including climate change, health, safety, and other social sustainability matters.

Executive Sustainability Committee. In 2021, the company established an executive sustainability committee, which is comprised of corporate and business unit senior executives. The committee is co-chaired by our vice president, chief accounting officer and controller and a business segment president. The executive sustainability committee responsibilities include:

- Supporting execution of, and making recommendations to advance, the company's environmental and sustainability strategy; and
- Establishing, maintaining, and enhancing the processes, procedures, and controls for the company's environmental and sustainability disclosures.

For information on our sustainability reporting, as well as highlights of our environmental stewardship and social responsibility, see "Sustainability Highlights" in the Proxy Summary.

Stockholder Engagement

The company has an active stockholder outreach program. We believe in providing transparent and timely information to our investors and understand the need to align our priorities with those of our key stakeholders. Each year we routinely engage directly or indirectly with our stockholders, including large institutional stockholders. Management regularly attends and presents at investor and financial conferences and holds one-on-one meetings with investors. During 2022, the company held meetings, conference calls, and webcasts with numerous stockholders and investment firms, including focused outreach to our top 30 investors. Our active stockholder outreach program includes:

WHO WE ENGAGE

- **Institutional Investors**
- **Sell-Side Analysts**
- **Retail Stockholders**
- **Pension Funds**
- **Holders of Bonds**
- **Rating Agencies/Firms**

HOW WE ENGAGE

- **One-on-One and Group Meetings**
- **Quarterly Earnings Conference Calls**
- **Written and Electronic Communications**
- **Company-Hosted Events and Presentations**
- **Webcasts with Stockholders and Analysts**
- **Industry and Sell-Side Presentations and Conferences**

WHO PARTICIPATES

- **Executive Management**
- **Investor Relations**
- **Senior Leadership**
- **Subject Matter Experts**
- **Board Members**

KEY ENGAGEMENT RESOURCES

- **MDU Resources Website at investor.mdu.com**
- **Quarterly Earnings Webcasts**
- **Annual Proxy Statement**
- **Annual Report**
- **Annual Stockholder Meeting**
- **Sustainability Report**
- **Public Events and Presentations**
- **SEC Filings**
- **Disclosures to Various Ratings Assessors**
- **Press Releases**

KEY TOPICS OF ENGAGEMENT

- **Company Strategy**
- **Executive Compensation**
- **Operational and Financial Updates**
- **Knife River Corporation Tax-Free Spinoff**
- **Strategic Review of MDU Construction Services Group, Inc.**
- **Capital Expenditure Forecast/Capital Allocation**
- **Sustainability**
- **Environmental, Social, and Corporate Governance Practices**

OUTCOMES OF STOCKHOLDER ENGAGEMENT

- **Received stockholder feedback regarding strategic initiatives**
- **Enhanced Sustainability Reporting with expanded disclosures of risk and opportunities in accordance with TCFD**
- **Cooperation Agreement entered into between the company and Corvex Management LP appointing a new director pending approval by the Federal Energy Regulatory Commission**
- **Stockholder feedback regularly shared with our board of directors**
- **Expanded disclosure of financial metrics for our business segments to help investors better understand key business drivers**

Stockholder Communications with the Board

Stockholders and other interested parties who wish to contact the board of directors or any individual director, including our non-employee chair or non-employee directors as a group, should address a communication in care of the secretary at MDU Resources Group, Inc., P.O. Box 5650, Bismarck, ND 58506-5650. The secretary will forward all communications.

Board Leadership Structure

The board separated the positions of chair of the board and chief executive officer in 2006, and our bylaws and corporate governance guidelines currently require that our chair be independent. The board believes this structure provides balance and is currently in the best interest of the company and its stockholders. Separating these positions allows the chief executive officer to focus on the full-time job of running our business, while allowing the chair to lead the board in its fundamental role of providing advice to and independent oversight of management. The chair meets and confers regularly between board meetings with the chief executive officer and consults with the chief executive officer regarding the board meeting agendas, the quality and flow of information provided to the board, and the effectiveness of the board meeting process. The board believes this split structure recognizes the time, effort, and energy the chief executive officer is required to devote to the position in the current business environment as well as the commitment required to serve as the chair, particularly as the board's oversight responsibilities continue to grow and demand more time and attention. The fundamental role of the board of directors is to provide oversight of the management of the company in good faith and in the best interests of the company and its stockholders. The board believes having an independent chair is a means to ensure the chief executive officer is accountable for managing the company in close alignment with the interests of stockholders including with respect to risk management as discussed below. The board has found that an independent chair is in a position to encourage frank and lively discussions including during regularly scheduled executive sessions consisting of only independent directors and to assure that the company has adequately assessed all appropriate business risks before adopting its final business plans and strategies. The board believes that having separate positions and having an independent outside director serve as chair is the appropriate leadership structure for the company at this time and demonstrates our commitment to good corporate governance.

Board's Role in Risk Oversight

Risk is inherent with every business, and how well a business manages risk can ultimately determine its success. We face a number of risks, including economic risks, strategic risks, operational risks, environmental and regulatory risks, competitive risks, climate and weather conditions, pension plan obligations, cyberattacks or acts of terrorism, and third party liabilities. The board, as a whole and through its committees, has responsibility for the oversight of risk management. In its risk oversight role, the board of directors has the responsibility to satisfy itself that the risk management processes designed and implemented by management are adequate for identifying, assessing, and managing risk. Management is responsible for identifying material risks, implementing appropriate risk management and mitigation strategies, and providing information regarding material risks and risk management and mitigation to the board. The company's risk oversight framework also aligns with its disclosure controls and procedures. For example, the company's quarterly and annual financial statements and related disclosures are reviewed by the disclosure committee, which includes certain senior management, who participate in the risk assessment practices described below.

The board believes establishing the right "tone at the top" and full and open communication between management and the board of directors are essential for effective risk management and oversight. Our chair meets regularly with our chief executive officer to discuss strategy and risks facing the company. The chair of the board and chairs of each of the board's standing committees meet with our chief executive officer, chief financial officer, and general counsel to discuss risks and presentations to the board regarding risks. Senior management attends the quarterly board meetings and is available to address questions or concerns raised by the board on risk management-related and any other matters. Each quarter, the board of directors and its applicable committees receive presentations from senior management on enterprise risk management issues and strategic matters involving our operations. Senior management annually presents an assessment to the board of critical enterprise risks that threaten the company's strategy and business model, including risks inherent in the key assumptions underlying the company's business strategy for value creation. Periodically, the board receives presentations from external experts on matters of strategic importance to the board. At least annually, the board holds strategic planning sessions with senior management to discuss strategies, key challenges, and risks and opportunities for the company.

In addition, in 2022 the company developed a survey completed by both the board of directors and members of the management policy committee to identify critical enterprise risks. The company believes this program, which was designed to enable effective and efficient identification of, and visibility into, critical enterprise risks over the short, intermediate, and long-term, and to facilitate the incorporation of risk considerations into decision making across the company, and assessing and managing the company's legal, regulatory, and other compliance obligations on a global basis, provides valuable insight to the board of directors in its risk oversight efforts. In particular, the company believes its enterprise risk management programs help clearly define risk management roles and responsibilities among the board, its committees and management, bring together senior management to discuss risk, promote visibility and constructive dialogue around the risks relevant to the company's strategy and operations and helps facilitate appropriate risk response strategies at the board of directors, board committees, and management.

The Board

While the board is ultimately responsible for risk oversight at our company, our standing board committees assist the board in fulfilling its oversight responsibilities in certain areas of risk.

Audit Committee	Compensation Committee	Nominating and Governance Committee	Environmental and Sustainability Committee
Risk Oversight Responsibilities	Risk Oversight Responsibilities	Risk Oversight Responsibilities	Risk Oversight Responsibilities
✓ Financial Reporting	✓ Executive Compensation	✓ Board Organization	✓ Environmental
✓ Internal Controls	✓ Incentive Plans	✓ Board Membership and Structure	✓ Health and Safety
✓ Cybersecurity	✓ Conflicts of Interest Assessment	✓ Succession Planning	✓ Social Sustainability
✓ Compliance with Legal and Regulatory Requirements	✓ Director Compensation Policy	✓ Corporate Governance	✓ Climate Change Risks

Management

The management policy committee meets monthly, or more frequently as warranted, to receive reports from each business unit on safety, operations, business development, and to discuss the company's challenges and opportunities. Reports are also provided by the company's financial, human resources, legal, and enterprise information technology departments. Special presentations are made by other employees on matters that affect the company's operations. The company has also developed a robust compliance program to promote a culture of compliance, consistent with the right "tone at the top," to mitigate risk. The program includes training and adherence to our code of conduct and legal compliance guide. We further mitigate risk through our internal audit and legal departments.

- **Audit Committee.** The audit committee assists the board in fulfilling its oversight responsibilities with respect to risk management in a general manner and specifically in the areas of financial reporting, internal controls, cybersecurity, compliance with legal and regulatory requirements, and related person transactions, and, in accordance with NYSE requirements, discusses with the board policies with respect to risk assessment and risk management and their adequacy and effectiveness. The audit committee receives regular reports on the company's compliance program, including reports received through our anonymous reporting hotline. It also receives reports and regularly meets with the company's external and internal auditors. During its quarterly meetings in 2022, the audit committee received presentations or reports from management on cybersecurity and the company's mitigation of cybersecurity risks as well as assessment and mitigation reports on other compliance and risk-related topics. The entire board was present for cybersecurity risk presentations and had access to the reports. The audit committee discussed areas where the company may have material risk exposure, steps taken to manage such exposure, and the company's risk tolerance in relation to company strategy. The audit committee reports regularly to the board of directors on the company's management of risks in the audit committee's areas of responsibility.

- **Compensation Committee.** The compensation committee assists the board in fulfilling its oversight responsibilities with respect to the management of risks arising from our compensation policies and programs.

- **Nominating and Governance Committee.** The nominating and governance committee assists the board in fulfilling its oversight responsibilities with respect to the management of risks associated with board organization, board membership and structure, succession planning for our directors and executive officers, and corporate governance.

- **Environmental and Sustainability Committee.** The environmental and sustainability committee assists the board in fulfilling its oversight responsibilities with respect to the management of risks related to environmental, human capital management, health, safety, and other social and sustainability matters that fundamentally affect the company's business interests and long-term viability. The environmental and sustainability committee responsibilities include reviewing significant risks and exposures to the company regarding current and emerging environmental and social sustainability matters, including climate change risks, and discussing with management and overseeing actions taken by the company in response thereto. The environmental and sustainability committee also reviews the company's efforts to integrate social, environmental, and economic principles, including climate change, greenhouse gas emissions management, energy, water, and waste management, product and service quality, reliability, customer care and satisfaction, public perception, and company reputation, into the company's strategy and operations. The environmental and sustainability committee receives regular reports on the company's safety statistics relating to organization-wide year-to-date recordable incident rates, days away, restricted or transferred rates, and preventable vehicle accident rates.

Board Meetings and Committees

During 2022, the board of directors held four regular meetings and seven special meetings. Each director attended at least 75% of the combined total meetings of the board and the committees on which the director served during 2022, in each case, during the time period which each director served. Directors are encouraged to attend our annual meeting of stockholders. All directors attended our 2022 annual meeting of stockholders.

The board has standing audit, compensation, nominating and governance, and environmental and sustainability committees which meet at least quarterly. The table below provides current committee membership.

Name	Audit Committee	Compensation Committee	Nominating and Governance Committee	Environmental and Sustainability Committee
German Carmona Alvarez		●	●	
Thomas Everist		●	●	
Karen B. Fagg		C		●
Patricia L. Moss		●		C
Dale S. Rosenthal	●		●	
Edward A. Ryan	●		C	
David M. Sparby	C			●
Chenxi Wang	●			●

C - Chair

● - Member

Below is a description of each standing committee of the board. The board has affirmatively determined that each of these standing committees consists entirely of independent directors pursuant to rules established by the NYSE, rules promulgated under the Securities and Exchange Commission (SEC), and the director independence standards established by the board. The board has also determined that each member of the audit committee and the compensation committee is independent under the criteria established by the NYSE and the SEC for audit committee and compensation committee members, as applicable.

Nominating and Governance Committee

Met Five Times in 2022

The nominating and governance committee met five times during 2022. The current committee members are Edward A. Ryan, chair, German Carmona Alvarez, Thomas Everist, and Dale S. Rosenthal.

The nominating and governance committee is governed by a written charter and provides recommendations to the board with respect to:

- board organization, membership, and function;
- committee structure and membership;
- succession planning for our executive management and directors; and
- our corporate governance guidelines.

The nominating and governance committee assists the board in overseeing the management of risks in the committee's areas of responsibility.

The committee identifies individuals qualified to become directors and recommends to the board the director nominees for the next annual meeting of stockholders. The committee also identifies and recommends to the board individuals qualified to become our principal officers and the nominees for membership on each board committee. The committee oversees the evaluation of the board and management.

In identifying nominees for director, the committee consults with board members, management, search firms, consultants, organizational representatives, and other individuals likely to possess an understanding of our business and knowledge concerning suitable director candidates.

In evaluating director candidates, the committee, in accordance with our corporate governance guidelines, considers an individual's:

- background, character, and experience, including experience relative to our company's lines of business;
- skills and experience which complement the skills and experience of current board members;
- success in the individual's chosen field of endeavor;
- skill in the areas of accounting and financial management, banking, business management, human resources, marketing, operations, public affairs, law, technology, risk management, and governance;
- background in publicly traded companies, including service on other public company boards of directors;
- geographic area of residence;
- business and professional experience, skills, gender, and ethnic background, as appropriate in light of the current composition and needs of the board;
- independence, including any affiliation or relationship with other groups, organizations, or entities; and
- compliance with applicable law and applicable corporate governance, code of conduct and ethics, conflict of interest, corporate opportunities, confidentiality, stock ownership and trading policies, and other policies and guidelines of the company.

Our bylaws also contain requirements that a person must meet to qualify for service as a director.

In addition, on January 24, 2023, the company entered into the Cooperation Agreement with Corvex Management LP, pursuant to which Corvex Management LP partner, James H. Gemmel, was appointed as a non-voting board observer and, subject to FERC approval, to the board of directors.

The nominating and governance committee assesses these considerations annually in connection with the nomination of directors for election at the annual meeting of stockholders. The committee seeks a collective background of board members to provide a portfolio of experience and knowledge that serves the company's governance and strategic needs and best perpetrates our long-term success. Directors should have demonstrated experience and knowledge that is relevant to the board's oversight role of the company's business. The nominating and governance committee also considers the board's diversity in recommending nominees, including diversity of experience, expertise, ethnicity, gender, and geography. The composition of the current board and the board nominees reflects diversity in business and professional experience, skills, ethnicity, gender, and geography.

Audit Committee

Met Nine Times in 2022

The audit committee is a separately-designated committee established in accordance with Section 3(a)(58)(A) of the Securities Exchange Act of 1934 and is governed by a written charter.

The audit committee met nine times during 2022. The current audit committee members are David M. Sparby, chair, Dale S. Rosenthal, Edward A. Ryan, and Chenxi Wang. The board of directors determined that Mr. Sparby and Ms. Rosenthal are "audit committee financial experts" as defined by SEC rules, and all audit committee members are financially literate within the meaning of the listing standards of the NYSE. All members also meet the independence standard for audit committee members under our director independence guidelines, the NYSE listing standards, and SEC rules.

The audit committee assists the board of directors in fulfilling its oversight responsibilities to the stockholders and serves as a communication link among the board, management, the independent registered public accounting firm, and the internal auditors. The audit committee reviews and discusses with management and the independent registered public accounting firm, before filing with the SEC, the annual audited financial statements and quarterly financial statements. The audit committee also:

- assists the board's oversight of:
    - the integrity of our financial statements and system of internal controls;
    - the company's compliance with legal and regulatory requirements and the code of conduct;
    - discussions with management regarding the company's earnings releases and guidance;
    - the independent registered public accounting firm's qualifications and independence;
    - the appointment, compensation, retention, and oversight of the work of the independent registered public accounting firm;
    - the performance of our internal audit function and independent registered public accounting firm; and
    - management of risk in the audit committee's areas of responsibility, including cybersecurity, financial reporting, legal and regulatory compliance, and internal controls.
- arranges for the preparation of and approves the report that SEC rules require we include in our annual proxy statement. See the section entitled "Audit Committee Report" for further information.

Compensation Committee

Met Seven Times in 2022

During 2022, the compensation committee met seven times. The compensation committee consists entirely of independent directors within the meaning of the company's corporate governance guidelines and the NYSE listing standards and who meet the definitions of non-employee directors for purposes of Rule 16-b under the Exchange Act. Current members of the compensation committee are Karen B. Fagg, chair, German Carmona Alvarez, Thomas Everist, and Patricia L. Moss.

The compensation committee is governed by a written charter and assists the board of directors in fulfilling its responsibilities relating to the company's compensation policies and programs. It has direct responsibility for determining compensation for our Section 16 officers and for overseeing the company's management of compensation risk in its areas of responsibility. In determining the long-term incentive component of CEO compensation, the compensation committee may consider, among others, the company's performance and relative stockholder return, the value of similar incentive awards given to CEOs at comparable companies and the awards given to the company's CEO in past years. The compensation committee also reviews and recommends any changes to director compensation policies to the board of directors. The authority and responsibility of the compensation committee is outlined in the compensation committee's charter.

The compensation committee uses analysis and recommendations from outside consultants, the chief executive officer, and the human resources department in making its compensation decisions. The chief executive officer, the chief human resources officer, and the general counsel regularly attend compensation committee meetings. The committee meets in executive session as needed. The processes and procedures for consideration and determination of compensation of the Section 16 officers as well as the role of our executive officers are discussed in the "Compensation Discussion and Analysis."

The compensation committee has sole authority to retain compensation consultants, legal counsel, or other advisers to assist in its duties. The committee is directly responsible for the appointment, compensation, and oversight of the work of such advisers. The compensation committee retained an independent compensation consultant, Meridian Compensation Partners, LLC (Meridian), to conduct a competitive analysis on executive compensation for 2022 and an analysis of CEO pay and performance. Prior to retaining an adviser, the compensation committee considered relevant factors to ensure the adviser's independence from management. Annually the compensation committee conducts a potential conflicts of interest assessment raised by the work of any compensation consultant and how such conflicts, if any, should be addressed. The compensation committee requested and received information from Meridian to assist in its potential conflicts of interest assessment. Based on its review and analysis, the compensation committee determined in 2022 that Meridian was independent from management. Meridian does not provide any services other than consultation services to the compensation committee on executive and director compensation matters. Meridian reports directly to the compensation committee and not to management. Meridian participated in executive sessions with the compensation committee without members of management present.

The board of directors determines compensation for our non-employee directors based upon recommendations from the compensation committee. In 2022, the compensation committee retained Meridian to conduct an analysis of the company's compensation for non-employee directors.

Environmental and Sustainability Committee

Met Five Times in 2022

The environmental and sustainability committee met five times during 2022. The committee is governed by a written charter and consists entirely of independent directors within the meaning of the company's corporate governance guidelines and the listing standards of the NYSE. The current members of the committee are Patricia L. Moss, chair, Karen B. Fagg, David M. Sparby, and Chenxi Wang.

The environmental and sustainability committee oversees and provides recommendations to the board with respect to the company's policies, strategies, public policy positions, programs, and performance related to environmental, workplace health, safety, human capital, and other social sustainability matters that fundamentally affect the company's business interests and long-term viability. The environmental and sustainability committee:

- reviews significant risks and exposures regarding current and emerging environmental and social sustainability matters, including climate change risks, and discusses with management and oversees actions taken by the company in response to such risks and exposures;
- reviews the company's environmental and social sustainability strategies, goals, commitments, policies, and performance;
- reviews human capital management related to the company's operations, including employee recruitment and retention, training, wellness, gender pay equity, diversity, and inclusion;
- reviews any fatality, serious injury, or illness involving an employee, customer, contractor, or third-party occurring in connection with the company's operations;
- reviews any material noncompliance by the company with environmental, health, and safety laws and regulations;
- reviews the company's efforts to integrate social, environmental, and economic principles, including climate change, greenhouse gas emissions management, energy, water and waste management, product and service quality, reliability, customer care and satisfaction, public perception, and company reputation with and into the company's strategy and operations;
- reviews the company's communication strategy and significant public disclosures relating to environmental and social sustainability matters;
- considers and advises the compensation committee on the company's performance with respect to incentive compensation metrics relating to environmental and social sustainability matters;
- reports to, advises, and makes recommendations to the board on environmental and social sustainability matters affecting the company; and
- reviews stockholder proposals related to environmental and social sustainability matters.

Additional Governance Features

Board and Committee Evaluations

Our corporate governance guidelines provide that the board of directors, in coordination with the nominating and governance committee, will annually review and evaluate the performance and functioning of the board and its committees. The self-evaluations are intended to facilitate a candid assessment and discussion by the board and each committee of its effectiveness as a group in fulfilling its responsibilities, its performance as measured against the corporate governance guidelines, and areas for improvement. The board and committee members are provided with a questionnaire and the results were anonymously aggregated and provided to the board and each committee. The results of the evaluations are reviewed and discussed in executive sessions of the committees and the board of directors. For more detail on our board evaluation process, see "Board Evaluations and Process for Selecting Directors" in the section entitled "Board of Directors."

Executive Sessions of the Independent Directors

The non-employee directors meet in executive session at each regularly scheduled quarterly board of directors meeting. The chair of the board presides at the executive session of the non-employee directors.

Director Resignation Upon Change of Job Responsibility

Our corporate governance guidelines require a director to tender his or her resignation after a material change in job responsibility. In 2022, no directors submitted resignations under this requirement.

Majority Voting in Uncontested Director Elections

Our corporate governance guidelines require that in uncontested elections (those where the number of nominees does not exceed the number of directors to be elected), director nominees must receive the affirmative vote of a majority of the votes cast to be elected to our board of directors. Contested director elections (those where the number of director nominees exceeds the number of directors to be elected) are governed by a plurality of the vote of shares present in person or represented by proxy at the meeting.

The board has adopted a director resignation policy for incumbent directors in uncontested elections. Any proposed nominee for re-election as a director shall, before he or she is nominated to serve on the board, tender to the board his or her irrevocable resignation that will be effective, in an uncontested election of directors only, upon (i) such nominee's receipt of a greater number of votes "against" election than votes "for" election at our annual meeting of stockholders; and (ii) acceptance of such resignation by the board of directors.

Director Overboarding Policy

Our bylaws and corporate governance guidelines state that a director may not serve on more than two other public company boards. Currently, all of our directors are in compliance with this policy.

Board Refreshment

Recognizing the importance of board composition and refreshment for effective oversight, the nominating and governance committee annually considers the composition and needs of the board of directors, reviews potential candidates, and recommends to the board nominees for appointment or election. The nominating and governance committee and the board are committed to identifying individuals with diverse backgrounds whose skills and experiences will enable them to make meaningful contributions to shaping the company's business strategy and priorities. To further board refreshment efforts, the nominating and governance committee engaged an independent global search firm in 2021 to assist with identifying, evaluating and recruiting a diverse pool of potential director candidates. As part of its consideration of director succession, the nominating and governance committee from time to time reviews, including when considering potential candidates, the appropriate skills and characteristics required of board members. The board considers diversity of skills, expertise, race, ethnicity, gender, age, education, geography, cultural background, and professional experiences in evaluating board candidates for expected contributions to an effective board. Independent directors may not serve on the board beyond the next annual meeting of stockholders after attaining the age of 76. Given the breadth of our businesses, we believe the mandatory retirement age allows us to benefit from experienced directors, with industry expertise, company institutional knowledge and historical perspective, stability, and comfort with challenging company management, while maintaining our ability to refresh the board through the addition of new members. Mr. Sparby and Mr. Ryan joined the board in 2018; Ms. Wang joined the board in 2019; Ms. Rosenthal joined the board in 2021; and Mr. Carmona Alvarez joined in 2022. On January 24, 2023, the company entered into the Cooperation Agreement with Corvex Management LP, pursuant to which Corvex Management LP partner, James H. Gemmel, was appointed as a non-voting board observer and, subject to FERC approval, to the board of directors. For further details on the Cooperation Agreement, see the section entitled "Corporate Governance."

Our corporate governance guidelines include our policy on consideration of director candidates recommended to us. We will consider candidates that our stockholders recommend in the same manner we consider other nominees. Stockholders who wish to recommend a director candidate may submit recommendations, along with the information set forth in the guidelines, to the nominating and governance committee chair in care of the secretary at MDU Resources Group, Inc., P.O. Box 5650, Bismarck, ND 58506-5650.

Stockholders who wish to nominate persons for election to our board at an annual meeting of stockholders must follow the applicable procedures set forth in Section 2.08 or 2.10 of our bylaws. Our bylaws are available on our website. See "Stockholder Proposals, Director Nominations, and Other Items of Business for 2023 Annual Meeting" in the section entitled "Information about the Annual Meeting" for further details.

Prohibitions on Hedging/Pledging Company Stock

The director compensation policy prohibits directors from hedging their ownership of common stock, pledging company stock as collateral for a loan, or holding company stock in an account that is subject to a margin call. The executive compensation policy prohibits executives from hedging their ownership of common stock, pledging company stock as collateral for a loan, or holding company stock in an account that is subject to a margin call.

Code of Conduct

We have a code of conduct and ethics, which we refer to as the Leading With Integrity Guide. It applies to all directors, officers, and employees. The Leading With Integrity Guide defines our values, our culture, and our commitments to stakeholders while setting expectations of employee conduct for legal and ethical compliance. We also have a Vendor Code of Conduct setting forth our expectations of vendors including ethical business practices, workplace safety, environmental stewardship, and compliance with applicable laws and regulations. Our Vendor Code of Conduct is available on our company website, which is not part of this Proxy Statement and is not incorporated by reference into this Proxy Statement.

We intend to satisfy our disclosure obligations regarding amendments to, or waivers of, any provision of the code of conduct that applies to our principal executive officer, principal financial officer, and principal accounting officer, and that relates to any element of the code of ethics definition in Regulation S-K, Item 406(b), and waivers of the code of conduct for our directors or executive officers, as required by NYSE listing standards, by posting such information on our website.

Proxy Access

Our bylaws allow stockholders to nominate directors for inclusion in our Proxy Statement subject to the following parameters:

Ownership Threshold:	3% of outstanding shares of our common stock
Nominating Group Size:	Up to 20 stockholders may combine to reach the 3% ownership threshold
Holding Period:	Continuously for three years
Number of Nominees:	The greater of two nominees or 20% of our board

We believe these proxy access parameters reflect a well-designed and balanced approach to proxy access that mitigates the risk of abuse and protects the interests of all of our stockholders. Stockholders who wish to nominate directors for inclusion in our Proxy Statement in accordance with proxy access must follow the procedures in Section 2.10 of our bylaws. See "Stockholder Proposals, Director Nominations, and Other Items of Business for 2023 Annual Meeting."

Cybersecurity Oversight

The audit committee reviewed reports and received presentations at each of its regular quarterly meetings in 2022 concerning cybersecurity-related issues including information security, technology risks, and risk mitigation programs. All members of the board of directors received copies of reports and were present during the presentations. In 2014, the board established a Cyber Risk Oversight Committee (CYROC) consisting of the company's chief information officer and chief financial officer as well as financial, information technology, and other leaders from the company's business segments. The CYROC provides management and the audit committee with analyses, appraisals, recommendations, and pertinent information concerning cyber defense of the company's electronic information, information technology, and operation technology systems. The company has implemented a cybersecurity training and compliance program to facilitate initial and continuing education for employees who have contact or potential contact with the company's data. External reviews are conducted to assess company information security programs and practices, including incident management, service continuity, and information security compliance programs. The company has not had an indication of a material cybersecurity breach and has not incurred any expenses, penalties, or settlements arising from a material cybersecurity breach. The company maintains a cyber liability insurance policy providing insurance coverage within the policy limits for liability losses and business interruption events arising from a material cybersecurity breach. The audit committee receives periodic briefings concerning cybersecurity, information security, technology risks, and risk mitigation programs.

Corporate Governance Materials

Stockholders can see our bylaws, corporate governance guidelines, board committee charters, and Leading With Integrity Guide on our website. The information on our website is not part of this Proxy Statement and is not incorporated by reference as part of this Proxy Statement.

Corporate Governance Materials	Website
• Bylaws	investor.mdu.com/governance/governance-documents
• Corporate Governance Guidelines	investor.mdu.com/governance/governance-documents
• Board Committee Charters for the Audit, Compensation, Nominating and Governance, and Environmental and Sustainability Committees	investor.mdu.com/governance/governance-documents
• Leading With Integrity Guide	www.mdu.com/about-us/integrity

Related Person Transaction Disclosure

The board of directors' policy for the review of related person transactions is contained in our corporate governance guidelines. The policy requires the audit committee to review any proposed transaction, arrangement or relationship, or series thereof:

- in which the company was or will be a participant;

- the amount involved exceeds $120,000; and
- a related person had or will have a direct or indirect material interest.

Prior to the company entering into a related person transaction that would be required to be disclosed under the SEC rules, the audit committee will, after a reasonable prior review and consideration of the material facts and circumstances, make a determination or recommendation to the board and appropriate officers of the company with respect to the transactions as the audit committee deems appropriate. The committee will prohibit any such related person transaction if it determines it to be inconsistent with the best interests of the company and its stockholders.

Related persons are directors, director nominees, executive officers, holders of 5% or more of our voting stock, and their immediate family members. Related persons are required promptly to report to our general counsel all proposed or existing related person transactions in which they are involved.

We had no related person transactions in 2022.

Cooperation Agreement

On January 24, 2023, the company entered into the Cooperation Agreement with Keith A. Meister and Corvex Management LP (Mr. Meister and Corvex Management LP, together with their respective affiliates, the Corvex Group).

Pursuant to the Cooperation Agreement, the company agreed, among other things, to appoint Corvex Management LP partner James H. Gemmel to the board of directors, subject to the approval of the Federal Energy Regulatory Commission under the Federal Power Act (FERC Approval). The Cooperation Agreement also provides that, prior to the receipt of the FERC Approval, Mr. Gemmel would be appointed as a non-voting board observer of the board of directors, effective immediately following the execution of the Cooperation Agreement on January 24, 2023, which he was on January 24, 2023.

Under the terms of the Cooperation Agreement, if FERC Approval had been obtained on or before the date that is fifteen (15) business days prior to the date on which the company expected to mail its proxy statement relating to the 2023 annual meeting of stockholders, then (i) immediately following the date of the FERC Approval, the size of the board of directors would have been increased by one director and Mr. Gemmel would have been appointed to the board of directors for a term expiring at the 2023 annual meeting and (ii) the company would nominate Mr. Gemmel for re-election at the 2023 annual meeting for a term expiring at the 2024 annual meeting of stockholders. The FERC Approval was not obtained prior to the 2023 proxy mailing deadline. If the FERC Approval is obtained after the 2023 proxy deadline, then, immediately after the later of the date the FERC Approval is received and the completion of the 2023 annual meeting, the size of the board of directors will be increased by one director and Mr. Gemmel will be appointed to the board of directors for a term expiring at the 2024 annual meeting. Upon Mr. Gemmel’s appointment to the board of directors, Mr. Gemmel will cease to be a non-voting board observer.

Pursuant to the Cooperation Agreement, the Corvex Group has agreed to abide by certain customary standstill restrictions, voting commitments, and other provisions. In addition, the Cooperation Agreement provides for customary director replacement procedures in the event Mr. Gemmel ceases to serve as a director or non-voting board observer under certain circumstances as specified in the Cooperation Agreement. Furthermore, in connection with Mr. Gemmel’s appointment, Corvex Management LP and Mr. Meister also entered into a customary confidentiality agreement with respect to the company’s information.

The Cooperation Agreement also provides that Mr. Gemmel (or his replacement pursuant to the Cooperation Agreement) will resign from the board of directors effective upon the earliest of the following (Resignation Event): (i) the second business day following such time as the Corvex Group ceases to hold a “net long position” (as defined in the Cooperation Agreement) of at least 8,100,000 shares of the company’s common stock; (ii) the later of each of (a) the closing of the company’s previously announced distribution of the equity of Knife River Corporation to the company’s stockholders and/or the closing of the sale, distribution or other disposal (in one or a series of transactions) of any such shares not so distributed, in each case, such that the company and any subsidiary thereof, no longer holds, directly or indirectly, any equity interest or any other securities in Knife River Corporation, and (b) the closing of the sale, distribution or other complete disposition of 100% of MDU Construction Services Group, Inc. or its business (in one or a series of transactions), such that the company and any subsidiary thereof, no longer holds any interest in the business of MDU Construction Services Group, Inc.; (iii) the date of the 2024 annual meeting, unless the board of directors has determined to nominate Mr. Gemmel (or his replacement pursuant to the Cooperation Agreement) for election at the 2024 annual meeting; and (iv) the material breach by the Corvex Group or Mr. Gemmel (or his replacement pursuant to the Cooperation Agreement) of the confidentiality agreement or certain provisions of the Cooperation Agreement.

The Cooperation Agreement will terminate on the earlier of (i) the date that Mr. Gemmel (or his replacement pursuant to the Cooperation Agreement) no longer serves as a non-voting board observer or a director and (ii) the occurrence of a Resignation Event.

COMPENSATION OF NON-EMPLOYEE DIRECTORS

Director Compensation for 2022

MDU Resources' non-employee directors are compensated for their service according to the MDU Resources Group Inc. Director Compensation Policy. Only one company employee, David L. Goodin, the company's president and chief executive officer, serves as a director. Mr. Goodin receives no additional compensation for his service on the board. Director compensation is reviewed annually by the compensation committee. The committee's independent compensation consultant provided an analysis of the company's director compensation for 2022. The analysis included research on market trends in director compensation as well as a review of director compensation practices of companies in our compensation benchmarking peer group. The independent compensation consultant, Meridian, prepared a report on director compensation which indicated the company's average annual cash and equity compensation for the company's non-employee directors was below the 50th percentile of the company's peer group. The compensation committee and board concurred with the independent compensation consultant's recommendations and adjusted the annual compensation of non-executive directors effective June 1, 2022 as follows:

	Prior to June 1, 2022	Effective June 1, 2022
Base Cash Retainer	$100,000	$110,000
Additional Cash Retainers:		
Non-Executive Chair	112,500	125,000
Audit Committee Chair	20,000	20,000
Compensation Committee Chair	15,000	15,000
Nominating and Governance Committee Chair	15,000	15,000
Environmental and Sustainability Committee Chair	15,000	15,000
Annual Stock Grant[1] - Directors (other than Non-Executive Chair)	140,000	150,000
Annual Stock Grant[2] - Non-Executive Chair	165,000	175,000

[1] The annual stock grant is a grant of shares of company common stock equal in value to $150,000.

[2] The annual stock grant is a grant of shares of company common stock equal in value to $175,000.

The annual stock grant for non-executive directors is for the director's service provided during the calendar year. The payment occurs in November each year following the regularly scheduled board of directors meeting. Directors serving less than a full year receive a prorated stock payment based on the number of months served in the applicable calendar year.

There are no meeting fees paid to the directors.

The following table outlines the compensation paid to our non-employee directors for 2022.

Name	Fees Earned or Paid in Cash ($)	Stock Awards ($)[1]	All Other Compensation ($)[2]	Total ($)
German Carmona Alvarez[3]	18,333	25,000	9	43,342
Thomas Everist	105,833	150,000	5,103	260,936
Karen B. Fagg	120,833	150,000	3,703	274,536
Dennis W. Johnson	225,625	175,000	5,103	405,728
Patricia L. Moss	120,833	150,000	2,603	273,436
Dale S. Rosenthal	105,833	150,000	103	255,936
Edward A. Ryan	120,833	150,000	1,603	272,436
David M. Sparby	125,833	150,000	5,853	281,686
Chenxi Wang	105,833	150,000	103	255,936

[1] Directors receive an annual payment of $150,000 in company common stock, except the non-executive chair who receives $175,000 in company common stock, under the MDU Resources Group, Inc. Non-Employee Director Long-Term Incentive Compensation Plan. Directors serving less than a full year receive a prorated stock payment based on the number of months served. All stock payments are measured in accordance with generally accepted accounting principles for stock-based compensation in Accounting Standards Codification Topic 718. The grant date fair value is based on the purchase price of our common stock on the grant date of November 21, 2022, which was $30.64 per share. The amount paid in cash for fractional shares is included in the amount reported in the stock awards column to this table.

[2] Includes group life insurance premiums and charitable donations made on behalf of the director as applicable. Amounts for life insurance premiums reflect prorated amounts for directors serving less than a full year based on the number of months served.

[3] Mr. Carmona Alvarez was elected to the board on November 17, 2022. The fees earned and stock award reflected above are prorated for his service during 2022.

Other Compensation

In addition to liability insurance, we maintain group life insurance in the amount of $100,000 on each non-employee director for the benefit of their beneficiaries during the time they serve on the board. The annual cost per director is $103.20. Directors who contribute to the company's Good Government Fund may designate up to four charities to receive donations from the company, depending on the amount of the director's contribution to the Good Government Fund. Directors are reimbursed for all reasonable travel expenses, including spousal expenses in connection with attendance at meetings of the board and its committees. Perquisites, if any, were below the disclosure threshold in 2022.

Deferral of Compensation

Directors may defer all or any portion of the annual cash retainer and any other cash compensation paid for service as a director pursuant to the Deferred Compensation Plan for Directors. Deferred amounts are held as phantom stock with dividend accruals and are paid out in cash over a five-year period after the director leaves the board. For directors who participated in the post-retirement income plan for directors before its termination in May 2001, the net present value of each director's benefit was calculated and converted into phantom stock which will be paid pursuant to the Deferred Compensation Plan for Directors.

Stock Ownership Policy

Our director stock ownership policy contained in our corporate governance guidelines requires each director to beneficially own our common stock equal in value to five times the director's annual cash base retainer. Shares acquired through purchases on the open market and received through our Non-Employee Director Long-Term Incentive Compensation Plan are considered in ownership calculations as well as other beneficial ownership of our common stock by a spouse or other immediate family member residing in the director's household. A director is allowed five years commencing January 1 of the year following the year of the director's initial election to the board to meet the requirements. The level of common stock ownership is monitored with an annual report made to the compensation committee of the board. All directors are in compliance with the stock ownership policy or are within the first five years of their election to the board. For further details on our director's stock ownership, see the section entitled "Security Ownership."

SECURITY OWNERSHIP

Security Ownership Table

The table below sets forth the number of shares of our common stock that each director, each named executive officer, and all directors and executive officers as a group owned beneficially as of February 28, 2023. Unless otherwise indicated, each person has sole investment and voting power (or share such power with his or her spouse) of the shares noted.

Name[1]	Shares of Common Stock Beneficially Owned	Percent of Class
German Carmona Alvarez	816	*
David C. Barney	107,887 [2,3]	*
Thomas Everist	667,152	*
Karen B. Fagg	92,827	*
David L. Goodin	385,045 [2]	*
Dennis W. Johnson	128,338 [4]	*
Nicole A. Kivisto	112,061 [2,5]	*
Patricia L. Moss	92,212	*
Dale S. Rosenthal	8,116	*
Edward A. Ryan	36,719	*
David M. Sparby	35,455	*
Jeffrey S. Thiede	126,972 [2]	*
Jason L. Vollmer	71,095 [2]	*
Chenxi Wang	17,505	*
All directors and executive officers as a group (19 in number)	2,060,498 [2,6]	1.0 %

* Less than one percent of the class. Percent of class is calculated based on 203,623,893 outstanding shares as of February 28, 2023.

[1] The table includes the ownership of all current directors, named executive officers, and other executive officers of the company without naming them.

[2] Includes full shares allocated to the officer's account in our 401(k) retirement plan.

[3] The total includes 687 shares owned by Mr. Barney's spouse.

[4] Mr. Johnson disclaims all beneficial ownership of the 163 shares owned by his spouse.

[5] The total includes 531 shares owned by Ms. Kivisto's spouse.

[6] Includes shares owned by a director's or executive's spouse regardless of whether the director or executive claims beneficial ownership.

Hedging Policy

The company's Director Compensation Policy and its Executive Compensation Policy prohibit our directors and executives from hedging their ownership of company stock. The Director Compensation Policy applies to all directors who are not full-time employees of the company. The Executive Compensation Policy applies to the executives of the company designated as an officer for purposes of Section 16 of the Securities Exchange Act of 1934 as well as all other executives of the company and its subsidiaries who participate in its Long-Term Performance-Based Incentive Plan and its Executive Incentive Compensation Plan. Under the policies, directors and executives are prohibited from engaging in transactions that allow them to own stock technically but without the full benefits and risks of such ownership, including, but not limited to, zero-cost collars, equity swaps, straddles, prepaid variable forward contracts, security futures contracts, exchange funds, forward sale contracts, and other financial transactions that allow the director or executive to benefit from the devaluation of the company's stock.

The company policies also prohibit directors, executives, and related persons from holding company stock in a margin account, with certain exceptions, or pledging company securities as collateral for a loan. Company common stock may be held in a margin brokerage account only if the stock is explicitly excluded from any margin, pledge, or security provisions of the customer agreement. "Related person" means an executive officer's or director's spouse, minor child, and any person (other than a tenant or domestic employee) sharing the household of a director or executive officer as well as any entities over which a director or executive officer exercises control.

Greater Than 5% Beneficial Owners

Based solely on filings with the SEC, the table below shows information regarding the beneficial ownership of more than 5% of the outstanding shares of our common stock.

Title of Class	Name and Address of Beneficial Owner	Amount and Nature of Beneficial Ownership	Percent of Class
Common Stock	**The Vanguard Group** 100 Vanguard Blvd. Malvern, PA 19355	22,021,300 [1]	10.83%
Common Stock	**BlackRock, Inc.** 55 East 52nd Street New York, NY 10055	18,827,655 [2]	9.30%
Common Stock	**State Street Corporation** State Street Financial Center One Lincoln Street Boston, MA 02111	16,216,240 [3]	7.97%

[1] Based solely on the Schedule 13G, Amendment No. 11, filed on February 9, 2023, The Vanguard Group reported sole dispositive power with respect to 21,738,805 shares, shared dispositive power with respect to 282,495 shares, and shared voting power with respect to 104,218 shares.

[2] Based solely on the Schedule 13G, Amendment No. 14, filed on January 24, 2023, BlackRock, Inc. reported sole voting power with respect to 18,214,136 shares and sole dispositive power with respect to 18,827,655 shares as the parent holding company or control person of BlackRock Life Limited; BlackRock Advisors, LLC; Aperio Group, LLC; BlackRock (Netherlands) B.V.; BlackRock Fund Advisors; BlackRock Institutional Trust Company, National Association; BlackRock Asset Management Ireland Limited; BlackRock Financial Management, Inc.; BlackRock Asset Management Schweiz AG; BlackRock Investment Management, LLC; BlackRock Investment Management (UK) Limited; BlackRock Asset Management Canada Limited; BlackRock (Luxembourg) S.A., BlackRock Investment Management (Australia) Limited; BlackRock Advisors (UK) Limited; and BlackRock Fund Managers Ltd.

[3] Based solely on the Schedule 13G, filed on February 10, 2023, State Street Corporation reported shared voting power with respect to 15,823,579 shares and shared dispositive power with respect to 16,216,240 shares as the parent holding company or control person of SSGA Funds Management, Inc.; State Street Global Advisors, Limited; State Street Global Advisors, LTD; State Street Global Advisors Europe Limited; State Street Global Advisors Asia, Limited; and State Street Global Advisors Trust Company.

Delinquent Section 16(a) Reports

Section 16 of the Securities Exchange Act of 1934, as amended, requires officers, directors, and holders of more than 10% of our common stock to file reports of their trading in our equity securities with the SEC. Based solely on a review of Forms 3, 4, and 5, and any amendments to these forms furnished to us during and with respect to 2022, or written representation that no Form 5 was required, all such reports were timely filed, except for a Form 4 for David L. Goodin, David C. Barney, Stephanie A. Barth, Trevor J. Hastings, Anne M. Jones, Nicole A. Kivisto, Karl A. Liepitz, Margaret (Peggy) A. Link, Jeffrey S. Thiede, and Jason L. Vollmer in February 2022 related to the award of restricted stock units that vest on December 31, 2024.

EXECUTIVE COMPENSATION

ITEM 2. ADVISORY VOTE TO APPROVE THE FREQUENCY OF FUTURE ADVISORY VOTES TO APPROVE THE COMPENSATION PAID TO THE COMPANY'S NAMED EXECUTIVE OFFICERS

In accordance with Section 14A of the Securities Exchange Act of 1934 and Rule 14a-21(b), we are asking our stockholders to indicate, on an advisory basis, whether future advisory votes to approve the compensation paid to our named executive officers should be held every year, every two years, or every three years. This proposal is also known as a "say-on-frequency" proposal.

Our board of directors has determined that our stockholders should have the opportunity to vote on the compensation of our named executive officers every year. The board of directors believes that giving our stockholders the right to cast an advisory vote every year on the compensation of our named executive officers is a good corporate governance practice and is in the best interests of our stockholders. Annual advisory votes provide the highest level of accountability and direct communication with our stockholders.

The board has discussed and carefully considered the alternatives regarding the frequency of future advisory votes to approve executive compensation in an effort to determine the approach that would best serve the company and its stockholders. Our board has considered several factors supporting an annual vote, including:

- An annual say-on-pay vote is consistent with past practice, as we have been conducting an annual vote since 2011.
- An annual say-on-pay vote provides us with immediate and direct input from our stockholders on our compensation principles and practices as disclosed in the proxy statement every year.
- An annual say-on-pay vote provides frequent feedback from our stockholders, which is consistent with our efforts to seek input from our stockholders regarding corporate governance and our compensation philosophy.
- The lack of an annual say-on-pay vote might make it more difficult for us to understand the outcome of a stockholder vote as to whether the stockholder vote pertains to the compensation disclosed in the current year proxy statement or pay practices over the previous year or two years. As a result, a frequency other than annual might make it more difficult for the board to understand and respond appropriately to the message being communicated by our stockholders.
- Our stockholders voted to recommend an annual say-on-pay vote at our 2017 annual meeting of stockholders.

By voting on this Item 2, stockholders are not approving or disapproving the board of directors' recommendation, but rather are indicating whether they prefer an advisory vote on named executive officer compensation be held every year, every two years, or every three years. Stockholders may also abstain from voting.

Although the board of directors intends to carefully consider the voting results of this proposal, it is an advisory vote and the results will not be binding on the board of directors or the company, and the board of directors may decide that it is in the best interests of our stockholders and the company to hold an advisory vote on executive compensation more or less frequently than the option selected by our stockholders. In accordance with Section 14A of the Exchange Act, the next "say-on-frequency" vote will be held no later than the annual meeting of the stockholders in 2029.

The board of directors recommends that an advisory vote on compensation paid to our named executive officers be held every year.

The frequency of every year, every two years, or every three years that receives the most votes of our common stock present in person or represented by proxy at the meeting and entitled to vote on the proposal will be the frequency for the advisory vote on executive compensation that has been recommended by our stockholders. Abstentions will not count as votes for or against any frequency. Broker non-votes are not counted as voting power present and, therefore, are not counted in the vote.

ITEM 3. ADVISORY VOTE TO APPROVE THE COMPENSATION PAID TO THE COMPANY'S NAMED EXECUTIVE OFFICERS

In accordance with Section 14A of the Securities Exchange Act of 1934 and Rule 14a-21(a), we are asking our stockholders to approve, in an advisory vote, the compensation of our named executive officers as disclosed in this Proxy Statement pursuant to Item 402 of Regulation S-K. As discussed in the Compensation Discussion and Analysis, the compensation committee and board of directors believe the current executive compensation program directly links compensation of the named executive officers to our financial performance and aligns the interests of the named executive officers with those of our stockholders. The compensation committee and board of directors also believe the executive compensation program provides the named executive officers with a balanced compensation package that includes an appropriate base salary along with competitive annual and long-term incentive compensation targets. These incentive programs are designed to reward the named executive officers on both an annual and long-term basis if they attain specified goals.

Our overall compensation program and philosophy for 2022 was built on a foundation of these guiding principles:

- we pay for performance, with over 58% of our 2022 total target direct compensation for the named executive officers in the form of performance-based incentive compensation;
- we review competitive compensation data for the named executive officers, to the extent available, and incorporate internal equity in the final determination of target compensation levels;
- we align executive compensation and performance by using annual performance incentives based on criteria that are important to stockholder value, including earnings, earnings per share, and earnings before interest, taxes, depreciation, and amortization (EBITDA); and
- we align executive compensation and performance by using long-term performance incentives based on total stockholder return relative to our peer group and financial measures important to company growth.

We are asking our stockholders to indicate their approval of our named executive officer compensation as disclosed in this Proxy Statement, including the Compensation Discussion and Analysis, the executive compensation tables, and narrative discussion. This vote is not intended to address any specific item of compensation, but rather the overall compensation of our named executive officers for 2022. Accordingly, the following resolution is submitted for stockholder vote at the 2023 annual meeting of stockholders:

> "RESOLVED, that the compensation paid to the company's named executive officers, as disclosed pursuant to Item 402 of Regulation S-K, including the Compensation Discussion and Analysis, compensation tables, and narrative discussion of this Proxy Statement, is hereby approved."

As this is an advisory vote, the results will not be binding on the company, the board of directors, or the compensation committee and will not require us to take any action. The final decision on the compensation of the named executive officers remains with the compensation committee and the board of directors, although the board and compensation committee will consider the outcome of this vote when making future compensation decisions.

The board of directors recommends a vote "for" the approval, on a non-binding advisory basis, of the compensation of the company's named executive officers, as disclosed in this Proxy Statement.

Approval of the compensation of the named executive officers requires the affirmative vote of a majority of the common stock present in person or represented by proxy at the meeting and entitled to vote on the proposal. Abstentions will count as votes against this proposal. Broker non-vote shares are not entitled to vote on this proposal and, therefore, are not counted in the vote.

INFORMATION CONCERNING EXECUTIVE OFFICERS

Information concerning the executive officers, including their ages as of December 31, 2022, present corporate positions, and business experience during the past five years, is as follows:

Name	Age	Present Corporate Position and Business Experience
David L. Goodin	61	Mr. Goodin was elected president and chief executive officer of the company and a director effective January 4, 2013. For more information about Mr. Goodin, see the section entitled "Item 1. Election of Directors."
Stephanie A. Barth	50	Ms. Barth was elected vice president, chief accounting officer and controller of the company effective September 30, 2017. Prior to that, she was controller of the company effective May 30, 2016, and served as vice president, treasurer and chief accounting officer of WBI Energy, Inc. effective January 1, 2015, and controller effective September 30, 2013.
Brian R. Gray	52	Mr. Gray was elected president and chief executive officer of Knife River Corporation effective March 1, 2023. Prior to that, he was president of Knife River Corporation effective January 1, 2023, and region president of Knife River Corporation-Northwest effective January 11, 2012.
Trevor J. Hastings	49	Mr. Hastings was elected president and chief executive officer of WBI Energy, Inc. effective October 16, 2017. Prior to that, he was vice president-business development and operations support of Knife River Corporation effective January 11, 2012.
Anne M. Jones	59	Ms. Jones was elected vice president and chief human resources officer effective November 11, 2021. Prior to that, she was vice president-human resources of the company, vice president-human resources, customer service, and safety at Montana-Dakota Utilities Co., Great Plains Natural Gas Co., Cascade Natural Gas Corporation, and Intermountain Gas Company effective July 1, 2013, and director of human resources for Montana-Dakota Utilities Co. and Great Plains Natural Gas Co. effective June 2008.
Nicole A. Kivisto	49	Ms. Kivisto was elected president and chief executive officer of Montana-Dakota Utilities Co., Cascade Natural Gas Corporation, and Intermountain Gas Company effective January 9, 2015. Prior to that, she was vice president of operations for Montana-Dakota Utilities Co. and Great Plains Natural Gas Co. effective January 3, 2014, and vice president, controller and chief accounting officer for the company effective February 17, 2010.
Karl A. Liepitz	44	Mr. Liepitz was elected vice president, general counsel and secretary effective February 6, 2021. Prior to that, he was assistant general counsel and assistant secretary effective January 1, 2017, and senior attorney and assistant secretary effective January 9, 2016. He held legal positions of increasing responsibility with the company since August 2003.
Margaret (Peggy) A. Link	56	Ms. Link was elected vice president and chief information officer effective December 1, 2017. Prior to that, she was chief information officer effective January 1, 2016, assistant vice president-technology and cybersecurity officer effective January 1, 2015, and director shared IT services effective June 2, 2009.
Jeffrey S. Thiede	60	Mr. Thiede was elected president and chief executive officer of MDU Construction Services Group, Inc. effective April 30, 2013, and president effective January 1, 2012.
Jason L. Vollmer	45	Mr. Vollmer was named vice president and chief financial officer effective November 23, 2020. Prior to that, he was vice president, chief financial officer and treasurer effective September 30, 2017, vice president, chief accounting officer and treasurer effective March 19, 2016, treasurer and director of cash and risk management effective November 29, 2014, and manager of treasury services and risk management effective June 30, 2014.

On August 4, 2022, the company announced its intention to separate its indirect, wholly owned subsidiary, Knife River Corporation, from the company. The separation is expected to be effected as a tax-free spinoff to the company's stockholders. If the spin-off transaction is completed, the company has announced that it expects Mr. Hastings and Mr. Liepitz to become officers of Knife River Corporation, in which case they will resign from the company at the time of the spinoff.

COMPENSATION DISCUSSION AND ANALYSIS

The Compensation Discussion and Analysis describes how our named executive officers were compensated for 2022 and how their 2022 compensation aligns with our pay-for-performance philosophy. It also describes the oversight of the compensation committee and the rationale and processes used to determine the 2022 compensation of our named executive officers including the objectives and specific elements of our compensation program.

The Compensation Discussion and Analysis contains statements regarding corporate performance targets and goals. The targets and goals are disclosed in the limited context of our compensation programs and should not be understood to be statements of management's expectations or estimates of results or other guidance. We specifically caution investors not to apply these statements to other contexts.

Our Named Executive Officers for 2022 were:

David L. Goodin	President and Chief Executive Officer (CEO)
Jason L. Vollmer	Vice President and Chief Financial Officer (CFO)
David C. Barney[1]	Former President and Chief Executive Officer - Construction Materials and Contracting Segment
Jeffrey S. Thiede	President and Chief Executive Officer - Construction Services Segment
Nicole A. Kivisto	President and Chief Executive Officer - Electric and Natural Gas Distribution Segments

[1] On February 16, 2023, the company announced that Mr. Barney would cease serving in his position as chief executive officer of Knife River Corporation, the company's construction materials and contracting segment, effective March 1, 2023.

Executive Summary

Compensation Committee Responsibilities and Objectives

The compensation committee is responsible for designing and approving our executive compensation program and setting compensation opportunities for our named executive officers. The objectives of our executive compensation program for executive officers are to:

- recruit, motivate, reward, and retain high performing executive talent required to create superior stockholder value;
- reward executives for short-term performance as well as for growth in enterprise value over the long-term;
- ensure effective utilization and development of talent by working in concert with other management processes - for example, performance appraisal, succession planning, and management development;
- help ensure that compensation programs do not encourage or reward excessive or imprudent risk taking; and
- provide a competitive package relative to industry-specific and general industry comparisons and internal equity, as appropriate.

The above executive compensation objectives outlined in our executive compensation policy are directly linked to our business strategy to ensure officers are focused on elements that drive our business success and create stockholder value.

Pay for Performance

To ensure management's interests are aligned with those of our stockholders and the performance of the company, the majority of the CEO's and the other named executive officers' compensation is dependent on the achievement of company performance targets. The charts below show the 2022 pay mix for the CEO and average 2022 pay mix of the other named executive officers, including base salary and the annual and long-term incentives at target.

Annual Base Salary

We provide our executive officers with base salary at a sufficient level to attract and retain executives with the knowledge, skills, and abilities necessary to successfully execute their job responsibilities. Consistent with our compensation philosophy of linking pay to performance, our executives receive a relatively smaller percentage of their overall target compensation in the form of base salary. In establishing base salaries, the compensation committee considers each executive's individual performance, the scope and complexities of their responsibilities, internal equity, and whether the base salary is competitive as measured against the base salaries of similarly situated executives in our compensation peer group and market compensation data.

Annual Cash Incentive Awards

We linked our 2022 annual cash incentive awards for our executive officers to performance by rewarding achievement of financial performance measures and ensuring our executive officers are focused and accountable for our growth and profitability. Each executive was assigned a target annual incentive award based on a percentage of the executive's base salary. The actual annual cash incentive realized was determined by multiplying the target award by the payout percentage associated with the achievement of the executive's performance measures.

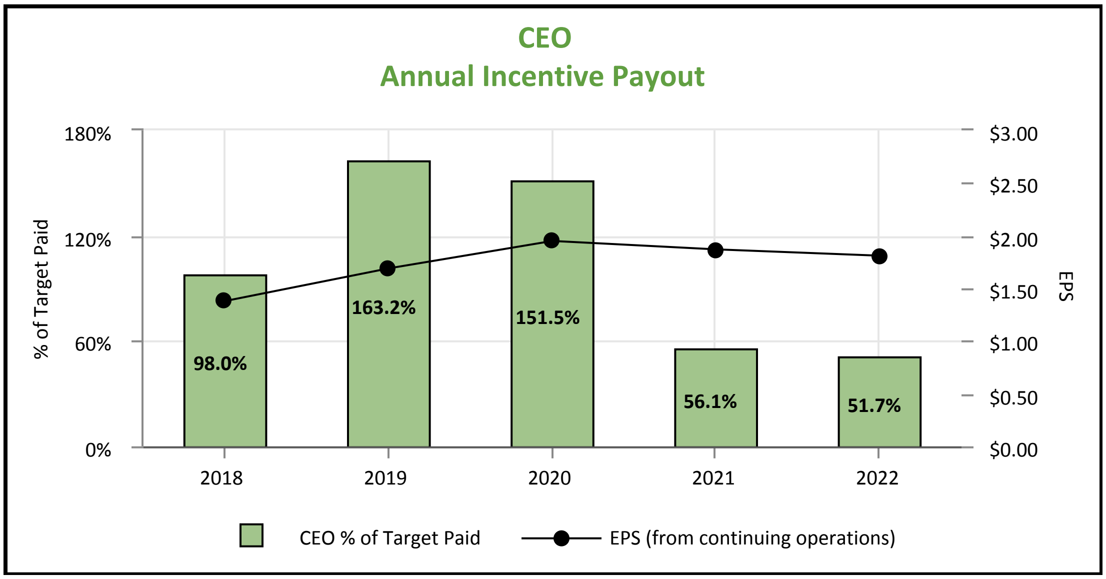
The annual cash incentive award for corporate executives (including our CEO and CFO) was based solely on the company's overall earnings per share (EPS) as adjusted and as described under the "Annual Cash Incentives" section in this Compensation Discussion and Analysis. This incentivizes the corporate executives to assist the business segments in their success and further links executive pay with the performance of the company.

Eighty percent of the annual cash incentive award for our business segment executives was based on specific business segment financial performance measures selected by the compensation committee. The other 20% of the business segment executives' annual incentive award was based on the achievement of overall company EPS as adjusted and as described under the "Annual Cash Incentives" section in this Compensation Discussion and Analysis. These measures incentivize our business segment executives to focus on the success and performance of their individual business segments while keeping the overall financial success of the company in mind.

In February 2022, the compensation committee approved the DEI modifier as part of the 2022 annual cash incentive award program for executive officers. The DEI modifier is based upon the company's achievement of certain initiatives to attract, retain, and develop a diverse and inclusive workforce. It includes a focus on representation of diverse employees in executive succession plans, outreach efforts to attract diverse candidates for open positions, implementing enhanced diversity, equity, and inclusion training as well as mentoring for new employees. The DEI modifier also includes the development of enhanced internal employee data dashboards to further support the company's efforts to attract, retain, and develop a diverse and inclusive workforce.

The 2022 DEI modifier provides executives with the opportunity to attain up to an additional 5% of their annual incentive target based on the achievement of the DEI initiatives as determined by the compensation committee. The compensation committee may also deduct up to 5% of the executives' annual incentives target if the compensation committee determines insufficient progress is made toward achieving the DEI initiatives.

As shown in the following chart, the percentage payout of the annual incentive target realized by our CEO compared to earnings per share from continuing operations for the last five years demonstrates the alignment between our financial performance and realized annual cash incentive compensation.



The percent of target paid for years 2018 through 2020 was based on adding each business segment's results weighted by its average invested capital compared to the company's total average invested capital. The percent of target paid for 2021 and 2022 was solely based on the company's EPS. In addition to the 51.7% payout received for achievement of the 2022 EPS performance measure, our CEO received an additional 5% of his annual incentive target based on the achievement of goals associated with the DEI modifier.

See the "Annual Cash Incentives" section within this Compensation Discussion and Analysis for further details on our company's annual cash incentive program.

Long-Term Equity-Based Incentive Awards

In February 2022, the compensation committee and the board approved grants of performance shares and restricted stock units which are eligible to vest into company stock, plus dividend equivalents, at the end of 2024. The performance shares, which comprise 75% of the award, will vest based on the achievement of two equally weighted performance measures, namely the company's total stockholder return (TSR) relative to a group of peer companies established for long-term incentive purposes and earnings growth as defined below over the three-year performance period. The restricted stock units, which comprise 25% of the award, enhance alignment with stockholders and serve as a retention tool. The restricted stock units will vest at the end of 2024, as long as the executive remains continuously employed with the company.

The long-term incentive granted in 2020 by the compensation committee and approved by the board in the form of performance shares vested at the end of 2022. Performance measures associated with the 2020-2022 performance period included earnings from continuing operations growth, earnings before interest, taxes, depreciation, and amortization (EBITDA) from continuing operations growth, and TSR relative to our peer group. Earnings growth and EBITDA growth were adjusted as described in the "Vesting of 2020-2022 Performance Share Awards" section within this Compensation Discussion and Analysis. These performance measures were selected to align pay and long-term performance goals.

Long-Term Performance Measures
for the 2020-2022 Performance Period

TSR Ranking	Earnings Growth	EBITDA Growth
50th **Percentile**	4.3% **Compound Annual Growth Rate**	7.1% **Compound Annual Growth Rate**
Target Ranking = 12th out of 22 Weighting = 50% **Weighted Vesting = 50.0%**	**Target Growth = 6.5%** Weighting = 25% **Weighted Vesting = 12.4%**	**Target Growth = 6.5%** Weighting = 25% **Weighted Vesting = 29.3%**

Total Vesting of 91.7%

See the "Long-Term Incentives" section within this Compensation Discussion and Analysis for further details on the company's long-term incentive program.

With the majority of our executive officers' compensation dependent on the achievement of robust performance measures set in advance by the compensation committee, we believe there is substantial alignment between executive pay and the company's performance.

Stockholder Advisory Vote ("Say on Pay")

At our 2022 annual meeting of stockholders, 95.7% of the votes cast on the "Say on Pay" proposal approved the compensation of our named executive officers. The compensation committee viewed the 2022 vote as an expression of the stockholders' general satisfaction with the company's executive compensation programs. The compensation committee reviewed the 2022 vote on "Say on Pay" and supports including performance based incentives.

Compensation Practices

Our practices and policies ensure alignment between the interests of our stockholders and our executives as well as effective compensation governance.

What We Do

☑ **Pay for Performance** - Annual incentive and the performance share award portion of the long-term incentive are tied to performance measures set by the compensation committee and comprise the largest portion of executive compensation.

☑ **Independent Compensation Committee** - All members of the compensation committee meet the independence standards under the New York Stock Exchange listing standards and the Securities and Exchange Commission rules.

☑ **Independent Compensation Consultant** - The compensation committee retains an independent compensation consultant to evaluate executive compensation plans and practices.

☑ **Competitive Compensation** - Executive compensation reflects executive performance, experience, relative value compared to other positions within the company, relationship to competitive market value compensation, corporate and business segment economic environment, and the actual performance of the overall company and the business segments.

☑ **Annual Cash Incentive** - Payment of annual cash incentive awards is based on overall company performance measured in terms of earnings per share in addition to business segment performance measured in terms of pre-established annual financial measures for business segment executives.

☑ **Long-Term Equity Incentive** - 2022 long-term incentive awards may be earned at the end of a three-year period. Payment of performance share awards, which represent 75% of the executive's long-term incentive, are based on the achievement of pre-established performance measures. Payment of time-vesting restricted stock unit shares, which represent 25% of the executive's long-term incentive, are based on retention of the executive at the end of the three-year period. All long-term incentives are paid through shares of common stock which encourages stock ownership by our executives.

☑ **Balanced Mix of Pay Components** - The target compensation mix represents a balance of annual cash and long-term equity-based compensation.

☑ **Mix of Financial Goals** - Use of a mixture of financial goals to measure performance prevents overemphasis on a single metric.

☑ **Diversity, Equity and Inclusion Modifier** - The 2022 annual cash incentive included a diversity, equity and inclusion (DEI) modifier aimed at furthering the company's diversity, equity and inclusion initiatives. The DEI modifier increases or decreases the annual incentive up to 5% based on the compensation committee's consideration of the company's progress on DEI initiatives.

☑ **Annual Compensation Risk Analysis** - Risks related to our compensation programs are regularly analyzed through an annual compensation risk assessment.

☑ **Stock Ownership and Retention Requirements** - Executive officers are required to own, within five years of appointment or promotion, company common stock equal to a multiple of their base salary. Our CEO is required to own stock equal to six times his base salary, and the other named executive officers are required to own stock equal to three times their base salary. The executive officers also must retain at least 50% of the net after-tax shares of stock vested through the long-term incentive plan for the earlier of two years or until termination of employment. Net performance shares must also be held until share ownership requirements are met.

☑ **Clawback Policy** - If the company's audited financial statements are restated due to any material noncompliance with the financial reporting requirements under the securities laws, the compensation committee may, or shall if required, demand repayment of some or all incentives paid to our executive officers within the last three years.

What We Do Not Do

☒ **Stock Options** - The company does not use stock options as a form of incentive compensation.

☒ **Employment Agreements** - Executives do not, in the normal course, have employment agreements entitling them to specific payments upon termination or a change of control of the company.

☒ **Perquisites** - Executives do not receive perquisites that materially differ from those available to employees in general.

☒ **Hedge Stock** - Executives are not allowed to hedge company securities.

☒ **Pledge Stock** - Executives are not allowed to pledge company securities in margin accounts or as collateral for loans.

☒ **No Dividends or Dividend Equivalents on Unvested Shares** - We do not provide for payment of dividends or dividend equivalents on unvested share awards.

☒ **Tax Gross-Ups** - Executives do not receive tax gross-ups on their compensation.

2022 Compensation Framework

Compensation Decision Process for 2022

The compensation committee's process for making executive compensation decisions for 2022 is depicted in the graphic below.

August 2021 Meeting
Set 2022 Salary Structure

November 2021 Meeting
Approve 2022 Executive Base Salaries and Incentive Targets

February 2022 Meeting
Approve Annual and Long-term Incentive Performance Measures for 2022 Plan Year

February 2023 Meeting
Approve Annual and Long-term Incentive Payouts for 2022 Plan Year

Compensation Policies and Practices as They Relate to Risk Management

The company completed an annual risk assessment of our 2022 compensation programs and concluded that our compensation policies and practices do not create risks which could have a material adverse effect on the company. After review and discussion of the assessment with the general counsel, chief human resources officer, and the chief executive officer, the company identified the following practices designed to prevent excessive risk taking:

- Business management and governance practices:
  - the use of human capital management systems and processes to attract, recruit, train, develop and retain employees to achieve short and long-term objectives;
  - risk management is a specific performance competency included in the annual performance assessment of executives;
  - board oversight on capital expenditure and operating plans promotes careful consideration of financial assumptions;
  - board approval on business acquisitions above a specific dollar amount or on any transaction involving the exchange of company common stock;
  - employee integrity training programs and anonymous reporting systems;
  - quarterly risk assessment reports at audit committee meetings; and
  - prohibitions on holding company stock in an account that is subject to a margin call, pledging company stock as collateral for a loan, and hedging of company stock by executive officers and directors.
- Executive compensation practices:
  - active compensation committee review of all executive compensation programs as well as comparison of company performance to its peer group;
  - use of independent consultants to assist in establishing pay targets and compensation structure.
  - initial determination of a position's salary grade to be at or near the 50th percentile of base salaries paid to similar positions at peer group companies and/or relevant industry companies;

- consideration of peer group and/or relevant industry practices to establish appropriate target compensation;
- a balanced compensation mix of base salary as well as annual and long-term incentives tied primarily to the company's financial and stock performance;
- use of interpolation for annual and long-term incentive awards to avoid payout cliffs;
- compensation committee negative discretion to adjust any annual incentive award payment downward;
- use of caps on annual incentive awards with a combined maximum of 200% of target for MDU Resources executives and the regulated energy delivery businesses and a combined maximum of 240% of target for construction materials and services businesses;
- use of caps on long-term incentive stock grant awards with a maximum of 200% of target;
- ability to clawback incentive payments in the event of a financial restatement;
- use of performance shares and restricted stock units, rather than stock options or stock appreciation rights, as an equity component of incentive compensation;
- use of performance shares for 75% of the long-term incentive award opportunity with relative total stockholder return and earnings growth performance measures;
- use of restricted stock units for 25% of the long-term incentive award opportunity to serve as a retention tool;
- use of three-year performance periods for performance shares and restricted stock units to discourage short-term risk-taking;
- substantive annual incentive goals measured primarily by earnings per share for all Section 16 officers in addition to segment earnings or segment EBITDA for business segment presidents, which are measures important to stockholders and encourage balanced performance;
- inclusion of a DEI modifier tied to the achievement of specific diversity, equity and inclusion initiatives;
- use of financial performance metrics that are readily monitored and reviewed;
- regular review of companies in the compensation and long-term incentive peer groups to ensure appropriateness and industry match;
- stock ownership requirements for board members and for executives participating in the MDU Resources Long-Term Performance-Based Incentive Plan; and
- mandatory holding periods of net after-tax company stock awards to executives until stock ownership requirements are achieved and mandatory holding periods for 50% of any net after-tax shares of stock earned under the long-term incentive awards until the earlier of (1) the end of the two-year period commencing on the date any stock earned under such award is issued, and (2) the executive's termination of employment.

Components of Compensation

Our executive compensation program is designed to promote sustained long-term profitability and create stockholder value. The components of our executive officers' compensation are selected to drive financial and operational results as well as align the executive officer's interests with those of our stockholders. Pay components and performance measures are considered by the compensation committee as fundamental measures of successful company performance and long-term value creation. The components of our 2022 executive compensation included:

Component	Purpose	How Determined	How it Links to Performance
Base Salary	Provides sufficient, regularly paid income to attract and retain executives with the knowledge, skills, and abilities necessary to successfully execute their job responsibilities.	Base salaries are recommended by the CEO for executives other than the CEO position to the compensation committee using analysis provided by the independent compensation consultant to target compensation within range of the 50th percentile using peer company and salary survey data. The compensation committee determines the base salary of the CEO based on input from the independent compensation consultant.	Base salary is a means to attract and retain talented executives capable of driving success and performance.
Annual Cash Incentive	Provides an opportunity to earn annual incentive compensation based on the achievement of financial and operating results important to the success of the company.	The annual cash incentive target is a percentage of base salary for the given executive position established by the compensation committee. Actual payment of the incentive is determined based on the achievement of performance measures and goals approved by the compensation committee.	Annual incentive performance measures are tied to the achievement of financial and DEI goals aimed to drive the success of the company and the individual business segments.
Performance Shares	Provides an opportunity to earn long-term equity compensation based on the achievement of performance measures aimed at long-term value creation and the company's strategic objectives.	Performance share awards represent 75% of an executive's long-term incentive award. The CEO recommends the target award amount for executives other than the CEO position to the compensation committee based on analysis provided by the independent compensation consultant. The compensation committee determines the target award for the CEO after consideration of input by the independent compensation consultant. Vesting of the award occurs at the end of a three-year period based on the achievement of performance measures established by the compensation committee.	Fosters ownership in company stock and aligns the executive's interests with those of stockholders in increasing long-term stockholder value.
Time-Vesting Restricted Stock Units	Provides an opportunity to earn long-term equity compensation through continued service through the vesting period.	Time-vesting restricted stock units represent 25% of an executive's long-term incentive award. The CEO recommends the target award amount for executives other than the CEO position to the compensation committee based on analysis provided by the independent compensation consultant. The compensation committee determines the target award for the CEO after consideration of input by the independent compensation consultant. Vesting of the award occurs at the end of a three-year period as long as the executive remains employed with the company through the vesting period.	Fosters continued leadership in the company to achieve company objectives through retention of key executives as well as aligning the executive's interests with those of stockholders in increasing long-term stockholder value.

Allocation of Total Target Compensation for 2022

Total target compensation consists of base salary plus target annual and long-term incentive compensation. Incentive compensation, which consists of annual cash incentive and long-term incentive awards vesting after three years, comprises the largest portion of our named executive officers' total target compensation because:

- equity awards align the interests of the named executive officers with those of stockholders by making a significant portion of their target compensation contingent upon results beneficial to stockholders;
- our named executive officers are in positions of authority to drive results, and therefore bear high levels of responsibility for our corporate performance;
- variable compensation helps ensure focus on the goals that are aligned with overall company strategy; and
- incentive compensation is at risk and dependent upon company performance and the satisfaction of performance objectives.

The compensation committee generally allocates a higher percentage of total target compensation to the target long-term incentive than to the target annual incentive for our higher level executives because they are in a better position to influence the company's long-term performance. The long-term incentive awards are paid in company common stock. These awards, combined with our stock retention requirements and our stock ownership policy, promote ownership of our stock by the executive officers. As a result, the compensation committee believes the executive officers, as stockholders, will be motivated to deliver long-term value to all stockholders.

Peer Groups

The compensation committee reviews the peer companies used for compensation analysis of executive positions and the company's relative total stockholder return performance periodically to assess their ongoing relevance and credibility.

Compensation Benchmarking Peer Group

The compensation committee's independent compensation consultant aids in the selection of appropriate peer companies for our compensation benchmarking peer group by evaluating potential peer companies in the construction and engineering, construction materials, utility and other related industries which are similar in size in terms of revenues and market capitalization. In 2022, the independent compensation consultant proposed and the compensation committee approved the removal of Jacobs Engineering Group, Inc. due to its increase in revenues and continued growth expectations from the compensation benchmarking peer group. MYR Group Inc. was recommended as an addition to the peer group based on its industry and comparable size in terms of revenues.

For review of compensation of the CEO and CFO positions, the independent compensation consultant used market data from 21 peer companies, shown in bold in the table below. For review of compensation of all other executive officer positions, the independent compensation consultant used compensation data from additional companies in Willis Towers Watson's 2021 General Industry Executive Compensation Survey.

Companies used for compensation analysis included:

2022 Compensation Peer Companies		
Alcoa Corporation	Eastman Chemical Company	**Pinnacle West Capital Corporation**
Allegheny Technologies Incorporated	Edison International	**Portland General Electric Company**
Alliant Energy Corporation	**EMCOR Group, Inc.**	PPL Corporation
Ameren Corporation	Entergy Corporation	Public Service Enterprise Group Incorporated
Atmos Energy Corporation	**Evergy Inc.**	**Quanta Services, Inc.**
Avery Dennison Corporation	Eversource Energy	Scotts Miracle-Gro Company
Avient Corporation	**Granite Construction Incorporated**	Sealed Air Corporation
Axalta Coating Systems LTD.	Graphic Packaging Holding Company	Sonoco Products Company
Ball Corporation	H.B. Fuller Company	**Southwest Gas Holdings, Inc.**
Berry Global Group, Inc.	**KBR, Inc.**	Spire Inc.
Black Hills Corporation	Kinross Gold Corporation	**Summit Materials, Inc.**
Cabot Corporation	**Martin Marietta Materials, Inc.**	UGI Corporation
Celanese Corporation	**MasTec, Inc.**	Valvoline Inc.
CenterPoint Energy, Inc.	The Mosaic Company	**Vulcan Materials Company**
CF Industries Holdings, Inc.	**MYR Group, Inc.**	**WEC Energy Group, Inc.**
The Chemours Company	Newmont Corporation	Westlake Chemical Corporation
CMS Energy Corporation	**NiSource Inc.**	Worthington Industries, Inc.
Crown Holdings, Inc.	OGE Energy Corp.	Xcel Energy Inc.
Dycom Industries, Inc.	ONE Gas, Inc.	

Companies shown in bold are the companies used for compensation analysis of the CEO and CFO positions and are considered our compensation benchmarking peer group.

Total Stockholder Return Performance Peer Group

To determine relative total stockholder return performance in conjunction with our 2022-2024 Performance Share Award, the independent compensation consultant recommended, and the compensation committee approved, using a peer group of 46 select companies within the utility, materials and construction and engineering industries from the S&P MidCap 400 Index as it is a stable, robust group of companies reflective of our company's size, value, and risk profile. During 2022, two out of the 46 companies were removed from the S&P MidCap 400 index due to a change in their market capitalization. Accordingly, relative total stockholder return was calculated based on the 44 remaining in the peer group as of December 31, 2022.

2022 Compensation for Our Named Executive Officers

2022 Base Salary and Incentive Targets

At its November 2021 meeting, the compensation committee approved the 2022 base salaries as well as the target annual and long-term incentive compensation for the named executive officers. At its February 2022 meeting, the compensation committee approved the annual and long-term incentive performance measures and goals for our named executive officers. In determining base salaries, target annual cash incentives, target long-term equity incentives, and total target compensation for our named executive officers, the compensation committee received and considered company and individual performance, market and peer data, responsibilities, experience, tenure in position, internal equity, and input and recommendations from the CEO, and the independent compensation consultant. The following information relates to each named executive officer's 2022 base salary, target annual cash incentive, target long-term equity incentive, and total target compensation:

David L. Goodin	2022 ($)	Compensation Component as a % of Base Salary
Base Salary	1,044,000	
Target Annual Cash Incentive Opportunity	1,305,000	125%
Target Long-Term Equity Incentive Opportunity	3,200,000	307%
Total Target Compensation	5,549,000	

The compensation committee considered information provided in Meridian's August 2021 compensation study showing Mr. Goodin's base salary, total cash compensation, and long-term incentives were below the median of the compensation peer group. Based on input from Meridian to move Mr. Goodin's compensation closer to the market median, the compensation committee increased Mr. Goodin's base salary by 4.4% and maintained his 2022 annual incentive target at 125% of his base salary. The compensation committee set Mr. Goodin's long-term incentive target at $3,200,000, which is an increase from 280% to 307% of his base salary based on input from Meridian to more closely align his long-term incentive with the market median for his position.

Jason L. Vollmer	2022 ($)	Compensation Component as a % of Base Salary
Base Salary	530,000	
Target Annual Cash Incentive Opportunity	397,500	75%
Target Long-Term Equity Incentive Opportunity	848,000	160%
Total Target Compensation	1,775,500	

The compensation committee considered information provided in Meridian's August 2021 compensation study showing Mr. Vollmer's base salary was below the market median based on peer group and compensation survey data. To move Mr. Vollmer closer to the market median, the CEO recommended and the compensation committee approved a base salary increase of 8.2% for Mr. Vollmer in 2022. The compensation committee maintained Mr. Vollmer's target annual cash incentive opportunity at 75% of base salary and increased his long-term incentive target from 150% to 160% of his base salary to more closely align with the market median for his position.

David C. Barney	2022 ($)	Compensation Component as a % of Base Salary
Base Salary	535,000	
Target Annual Cash Incentive Opportunity	401,250	75%
Target Long-Term Equity Incentive Opportunity	856,000	160%
Total Target Compensation	1,792,250	

The compensation committee considered information provided in Meridian's August 2021 compensation study in their review of the recommendation made by the CEO concerning Mr. Barney's compensation. Mr. Barney received a 4.4% increase in base salary for 2022. The compensation committee maintained Mr. Barney's target annual cash incentive opportunity at 75% of his base salary and increased his long-term incentive target from 150% to 160% of his base salary to more closely align with the market median for his position.

Jeffrey S. Thiede	2022 ($)	Compensation Component as a % of Base Salary
Base Salary	530,000	
Target Annual Cash Incentive Opportunity	397,500	75%
Target Long-Term Equity Incentive Opportunity	848,000	160%
Total Target Compensation	1,775,500	

The compensation committee considered information provided in Meridian's August 2021 compensation study in their review of the recommendation made by the CEO concerning Mr. Thiede's compensation. Mr. Thiede received a 4.4% increase in his base salary for 2022. The compensation committee maintained Mr. Thiede's target annual cash incentive opportunity at 75% of his base salary and increased his long-term incentive target from 150% to 160% of his base salary to more closely align with the market median for his position.

Nicole A. Kivisto	2022 ($)	Compensation Component as a % of Base Salary
Base Salary	530,000	
Target Annual Cash Incentive Opportunity	397,500	75%
Target Long-Term Equity Incentive Opportunity	848,000	160%
Total Target Compensation	1,775,500	

The compensation committee considered information provided in Meridian's August 2021 compensation study in their review of the recommendation made by the CEO concerning Ms. Kivisto's compensation. Ms. Kivisto received a base salary increase of 4.4% for 2022. The compensation committee maintained her target annual cash incentive opportunity at 75% of her base salary and increased her long-term incentive target from 150% to 160% of her base salary to more closely align with the market median for her position.

Annual Cash Incentives

Business segment executives receive their annual cash incentive awards through the achievement of financial performance measures specific to their business segment plus a performance measure tied to overall company earnings per share. Our CEO and CFO earn their annual cash incentive award based solely on the achievement of overall company earnings per share. Through this, our business segment executives are incentivized to primarily focus on the success and performance of their business segments while keeping the overall financial success of the company in mind, whereas our corporate executives are incentivized to assist in the success and performance of all lines of business.

The compensation committee selected the following financial performance measures to ensure that compensation to the executives reflects the success of their respective business segments and the overall company.

Mr. Goodin and Mr. Vollmer	**100% EPS**
Mr. Barney	**80% Construction Materials and Contracting EBITDA**
	20% EPS
Mr. Thiede	**80% Construction Services EBITDA**
	20% EPS
Ms. Kivisto	**80% Electric and Natural Gas Distribution Earnings**
	20% EPS

The compensation committee selected earnings per share from continuing operations as the shared financial metric as it is a key indicator of company results and used to communicate annual performance expectations with the financial community. The earnings per share target of $2.07 reflects our 2022 financial goal to achieve an estimated return on invested capital of 7.7%.

The compensation committee selected EBITDA from continuing operations as the performance metric for the construction materials and contracting and construction services segment presidents as it is a financial performance metric common to the construction industry and encourages the presidents to focus on growth by excluding the impact of items such as taxes, interest, depreciation and amortization from the performance result which are largely out of their control. The target of $331 million in EBITDA from continuing operations for the construction materials and contracting segment and $180 million in EBITDA from continuing operations for the construction services segment reflects the financial goal needed to achieve returns on invested capital of 9.5% and 24.1% for the construction materials and contracting and construction services segments, respectively.

The compensation committee selected earnings from continuing operations as the performance metric for the electric and natural gas distribution segments as regulated utilities are valued based on earnings potential and rate base. The 2022 target of $110 million reflects the financial goal needed to achieve a return on invested capital of 4.9% and the continued investment in infrastructure and regulatory recovery from completed and pending rate cases.

In addition to the financial performance measures, the environmental and sustainability committee approved and recommended a DEI modifier be included as part of the executive's 2022 annual incentive which was then approved by the compensation committee at its February 2022 meeting. The DEI modifier is a separate performance measure, independent of the achievement of the financial performance measures and is based on the compensation committee's assessment of management's progress toward the completion of the following DEI initiatives:

- Enhance the formal succession planning process to include the review of the positions of all Section 16 officers, key executives and business segment officers and to ensure diverse representation in terms of gender, ethnicity, individuals with disabilities and veteran status and the development of candidates being prepared for these positions.
- Increase outreach activities and efforts aimed at attracting diverse candidates to positions within our businesses.
- Enhance new employee onboarding processes to include DEI training and formal mentoring programs.
- Implement a consistent human resources dashboard across all businesses to build baseline information and track key metrics to provide insight into the make-up and diversity of our employee population.

The DEI modifier applies equally to all executives and adds or deducts up to 5% of the executives annual incentive target based on the compensation committee's assessment.

All financial performance measures are from continuing operations plus earnings or losses from any discontinued operations after December 31, 2021. To incentivize executives to make decisions that have long-term positive impact, even at the expense of short-term results, and to prevent one-time gains and losses from having an undue impact on incentive payments, the compensation committee designed its annual incentive measures to allow for adjustments for certain unplanned events that impact our performance targets but are not indicative of underlying business performance. The compensation committee may approve adjustments to the financial results to remove the following items, as applicable, from the performance measure:

- The negative effect on earnings/EBITDA from asset sales/dispositions/retirements.
- The effect on earnings/EBITDA from withdrawal liabilities relating to multiemployer pension plans.
- The effect on earnings/EBITDA from transaction costs incurred for acquisitions or mergers.
- The effect on earnings from unanticipated changes and interpretation of tax law.

The compensation committee will consider for removal the positive effect on earnings/EBITDA from assets sales/dispositions/retirements if it determines the positive effect is not indicative of underlying business performance.

For the 2022 annual cash incentive, the compensation committee approved adjustments to the construction materials and contracting segment EBITDA from continuing operations to remove the effect of transaction costs incurred for acquisitions and mergers. In the calculation of EPS from continuing operations, the compensation committee approved adjustments for the effect of transaction costs incurred for acquisitions and mergers, costs incurred associated with the company's intent to separate the construction materials and contracting segment pursuant to a tax-free spinoff and, costs incurred in connection with the company's strategic review to optimize the value of the construction services segment.

To determine the payout associated with each financial performance measure:

- Actual performance results are compared to the target performance measure which results in the percent of target achieved.
- The percent of target achieved is translated into a payout percentage of the executive's target award opportunity using linear interpolations for results between threshold and target as well as target and maximum.

Achievement of 100% of the target performance measure results in a payout of 100% of the target award opportunity. Results achieved below the established threshold result in no payout. The threshold, target and maximum performance levels as well as the associated payout opportunity are depicted in the following chart:

	Threshold		Target		Maximum	
Measure	**% of Target**	**Payout %**		**Payout %**	**% of Target**	**Payout %**
MDU Resources EPS*	85%	25%	$2.07	100%	115%	200%
Electric and Natural Gas Distribution Earnings	90%	50%	$110 million	100%	110%	200%
Construction Materials and Contracting EBITDA	75%	25%	$331 million	100%	115%	250%
Construction Services EBITDA	65%	25%	$180 million	100%	115%	250%

*EPS is weighted 20% of the award for business segment presidents and 100% of the award for corporate officers.

2022 Annual Incentive Results

The 2022 performance measure results, percent of target achieved based on those results, and the associated payout percentages reflect the company's 2022 financial performance and are presented below:

Business Segment	Performance Measure	Result	Percent of Performance Measure Achieved	Percent of Award Opportunity Payout	Weight	Weighted Award Opportunity Payout %
MDU Resources Corporate Officers	Earnings per Share[1]	$1.87	90.3%	51.7%	100%	51.7%
All Business Segment Presidents	Earnings per Share[1]	$1.87	90.3%	51.7%	20%	10.3%
Electric and Natural Gas Distribution	Earnings	$102.2 million	93.0%	64.8%	80%	51.8%
Construction Materials and Contracting	EBITDA[2]	$307.5 million	92.8%	78.5%	80%	62.8%
Construction Services	EBITDA	$193.4 million	107.4%	173.7%	80%	139.0%

[1] Earnings used to calculate EPS from continuing operations were adjusted to remove the effect of transaction costs incurred for acquisitions and mergers as well as costs incurred associated with the company's intent to separate the construction materials and contracting segment pursuant to a tax-free spinoff and the strategic review to optimize the value of the construction services segment.

[2] Construction materials and contracting segment EBITDA from continuing operations was adjusted to remove the effect of transaction costs incurred for acquisitions and mergers.

The compensation committee further assessed management's progress toward completing the performance measures related to the company's DEI initiatives, including:

- The enhancement of the succession planning process to include all executive officer positions at the corporate and business unit level along with the identification of candidate diversity in terms of gender, ethnicity, veteran status and disability.
- Development plans were determined for all candidates identified in the succession planning process.
- Onboarding processes were enhanced to include diversity, equity and inclusion training as well as formal mentoring programs.
- A system was established to track outreach activities and efforts aimed at attracting diverse candidates to positions within the company.
- A human resources dashboard was implemented across all businesses to consistently track employment metrics and trends.

Based on these accomplishments the compensation committee awarded a DEI modifier award of 5.0% of the executive's target annual incentive. Based on the achievement of the performance targets and the DEI modifier, the named executive officers received the following 2022 annual incentive compensation:

		Annual Incentive Earned			
Name	Target Annual Incentive ($)	Payout Percentage on financial measures (%)	DEI Modifier (%)	Total payout percentage (%)	Amount ($)
David L. Goodin	1,305,000	51.7	5.0	56.7	739,935
Jason L. Vollmer	397,500	51.7	5.0	56.7	225,383
David C. Barney	401,250	73.1	5.0	78.1	313,377
Jeffrey S. Thiede	397,500	149.3	5.0	154.3	613,343
Nicole A. Kivisto	397,500	62.1	5.0	67.1	266,723

Long-Term Incentives

All of our named executive officers participated in the 2022 long-term incentive plan which consists of 75% performance shares that align long-term compensation with the achievement of pre-determined financial performance measures and 25% time-vesting restricted stock units that incentivize retention of our executives and alignment with the interests of our stockholders. Long-term incentive compensation comprised 57.7% of the CEO's 2022 total target compensation and 47.7% of the average of the other named executive officer's total target compensation. Stock earned under long-term incentive compensation is subject to our stock retention requirements.

Grant of 2022-2024 Long-Term Equity Incentive Awards

On February 16, 2022, the compensation committee determined the target number of performance shares and time-vesting restricted stock units to be granted to each named executive officer for the 2022-2024 vesting period by dividing the executive's target long-term award amount by the average of the closing prices of our stock from January 1 through January 22, 2022, which was $30.47 per share. Based on this price, the compensation committee awarded 75% of the target long-term incentive grant as performance shares and 25% of the target long-term incentive grant as time-vesting restricted stock units as shown below:

Name	Base Salary ($)	Target Long-Term Incentive of Base Salary (%)	Long-Term Incentive Target ($)	Total Target Long-Term Incentive Shares (#)	75% Performance Shares (#)	25% Time-Vesting Restricted Stock Units (#)
David L. Goodin	1,044,000	307	3,200,000	105,021	78,766	26,255
Jason L. Vollmer	530,000	160	848,000	27,830	20,873	6,957
David C. Barney	535,000	160	856,000	28,093	21,070	7,023
Jeffrey S. Thiede	530,000	160	848,000	27,830	20,873	6,957
Nicole A. Kivisto	530,000	160	848,000	27,830	20,873	6,957

The performance share portion of the grant may vest at the end of a three-year period between 0% and 200%. The determination of vesting is based on the achievement of two separate performance measures each making up 50% of the award:

- Total stockholder return relative to that of a group of peer companies selected from the S&P 400 MidCap Index is the measure to align with the company's performance relative to our peers; and
- Compound annual growth rate in earnings from continuing operations is the measure to encourage continued growth of the company.

Earnings used to calculate earnings growth from continuing operations for the 2022 awards may be adjusted, as such adjustments are approved by the compensation committee, to remove:

- the effect on earnings from losses/impairments on asset sales/dispositions/retirements;
- the effect on earnings from withdrawal liabilities relating to multiemployer pension plans;
- the effect on earnings from costs incurred for acquisitions or mergers; and
- the effect on earnings from unanticipated tax law changes.

Vesting of performance shares and associated dividend equivalents is predicated on achievement of established levels associated with each performance measure. Threshold, target and maximum payouts as a percentage of target performance for the 2022 measures are:

	The Company's Relative TSR Percentile Rank	The Company's Earnings Growth Rate as a Percentage of Target	Vesting Percentage of Award Target
Maximum	75th or higher	153.8% of target or higher	200%
Target	50th	Target	100%
Threshold	25th	46.2% of target	20%
Below threshold	Less than 25th	less than 46.2% of target	0%

We do not disclose the earnings growth rate performance measure target until payout as such disclosure could result in competitive harm. Vesting for performance falling between the intervals is interpolated.

The time-vesting restricted stock units represent 25% of the long-term incentive opportunity and will vest on December 31, 2024, as long as the executive remains continuously employed with the company.

Vesting of 2020-2022 Performance Share Awards

For the 2020-2022 performance period, the long-term incentive program consisted solely of performance shares as the compensation committee did not adopt the use of time-vesting restricted stock units until 2021. The performance criteria used for vesting of the 2020-2022 performance share awards was:

- 50% based on our company's total stockholder return as a percentile of the total stockholder return of our peer companies over the three-year performance period;
- 25% based on EBITDA growth from continuing operations over the three-year performance period; and
- 25% based on earnings growth from continuing operations over the three-year performance period.

Performance Criteria	Target	Result	Vesting %	Weighting	Weighted Payout
Relative TSR Percentile Ranking	50th	50th	100.0%	50%	50.0%
EBITDA Growth*	6.5%	7.1%	117.1%	25%	29.3%
Earnings Growth*	6.5%	4.3%	49.7%	25%	12.4%
Total Weighted Payout					91.7%

*The 2022 EBITDA and earnings from continuing operations results used in the calculation of EBITDA growth and earnings growth were adjusted to remove the effect of costs incurred for acquisitions and mergers as well as costs incurred related to the company's intent to separate the construction materials and contracting segment pursuant to a tax-free spinoff and the strategic review to optimize the value of the construction services segment.

The named executive officers received the following long-term compensation awards for the 2020-2022 performance period:

Name	Target Performance Shares (#)	Performance Shares Vested (#)	Dividend Equivalents ($)
David L. Goodin	82,191	75,369	193,322
Jason L. Vollmer	18,082	16,581	42,530
David C. Barney	20,034	18,371	47,122
Jeffrey S. Thiede	20,034	18,371	47,122
Nicole A. Kivisto	20,034	18,371	47,122

2023-2025 Long-Term Incentive Awards

The compensation committee did not award performance shares to the executive officers for the 2023-2025 performance period due to the company's pending plans to separate the construction materials and contracting segment into a standalone public company and exploring strategic alternatives for the construction services segment in 2023. The committee awarded only time-vesting restricted stock units due to the company's significant strategic initiatives underway and as a means of retention for executive officers of both entities during the pending separation process. The compensation committee intends to resume awarding performance vesting shares in 2024.

Stock Retention Requirement

The named executive officers must retain 50% of the net after-tax shares vested pursuant to the long-term incentive awards for the earlier of two years from the date the vested shares are issued or the executive's termination of employment. The executive officer is also required to retain all vested share awards net of taxes if the executive has not met the stock ownership requirements under the company's stock ownership policy for executives.

Other Benefits

The company provides post-employment benefit plans and programs in which our named executive officers may be participants. We believe it is important to provide post-employment benefits which approximate retirement benefits paid by other employers to executives in similar positions. The compensation committee periodically reviews the benefits provided to maintain a market-based benefits package. Our named executive officers participated in the following plans during 2022 which are described below:

Plans	David L. Goodin	Jason L. Vollmer	David C. Barney	Jeffrey S. Thiede	Nicole A. Kivisto
Pension Plans	Yes	Yes	No	No	Yes
401(k) Retirement Plan	Yes	Yes	Yes	Yes	Yes
Supplemental Income Security Plan	Yes	No	Yes	No	Yes
Company Credit to Deferred Compensation Plan	No	Yes	Yes	Yes	No

Pension Plans

Effective in 2006, the defined benefit pension plans were closed to new non-bargaining unit employees and as of December 31, 2009, the defined benefit plans were frozen. For further details regarding the company's pension plans, refer to the section entitled "Pension Benefits for 2022."

401(k) Retirement Plan

The named executive officers as well as employees working a minimum of 1,000 hours per year are eligible to participate in the 401(k) retirement plan (401(k) plan) and defer annual income up to the Internal Revenue Service (IRS) limit. The named executive officers receive a company match up to 3% depending on their elected deferral rate. Contributions and the company match are invested in various funds based on the employee's election including company common stock.

In 2010, the company began offering increased company contributions to our 401(k) plan in lieu of pension plan contributions. For non-bargaining unit employees hired after 2006 or employees who were not previously participants in the pension plan, the added retirement contribution is 5% of plan eligible compensation. For non-bargaining unit employees hired prior to 2006 who were participants in the pension plan, the added retirement contributions are based on the employee's age as of December 31, 2009. The retirement contribution is

11.5% for Mr. Goodin, 9.0% for Ms. Kivisto, 7.0% for Mr. Vollmer, and 5.0% for Messrs. Barney and Thiede. These amounts may be reduced in accordance with the provisions of the 401(k) plan to ensure compliance with IRS limits.

Supplemental Income Security Plan

We offered certain key managers and executives benefits under a nonqualified retirement plan referred to as the Supplemental Income Security Plan (SISP). The SISP provides participants with additional retirement income and/or death benefits payable for 15 years. Effective February 11, 2016, the SISP was amended to exclude new participants to the plan and freeze current benefit levels for existing participants. For further details regarding the company's SISP, refer to the section entitled "Pension Benefits for 2022." Named executive officers participating in the SISP are Messrs. Goodin and Barney and Ms. Kivisto.

The following table reflects the SISP benefits as of December 31, 2022 available to our named executive officers:

	SISP Benefits	
Name	**Annual Death Benefit ($)**	**Annual Retirement Benefit ($)**
David L. Goodin	552,960	276,480
Jason L. Vollmer	n/a	n/a
David C. Barney	262,464	131,232
Jeffrey S. Thiede	n/a	n/a
Nicole A. Kivisto	157,728	78,864

MDU Resources Group, Inc. Deferred Compensation Plan

The company adopted the MDU Resources Group, Inc. Deferred Compensation Plan (DCP) effective January 1, 2021, which provides a select group of management and other highly compensated employees the opportunity to defer compensation for retirement and other financial purposes. Participants in the plan may defer a portion of their salary and/or annual incentive. The compensation committee, upon recommendation from the CEO, may approve company contributions for select participants which vest over a three-year period. Company contributions recognize the participant's contributions to the company and serve as a retention tool. After satisfying the vesting requirements, distribution will be made in accordance with the terms of the plan. For further details regarding the company's DCP, refer to the section entitled "Nonqualified Deferred Compensation for 2022."

For 2022, the compensation committee selected and approved company contributions of $79,500 to Mr. Vollmer, $150,000 to Mr. Barney, and $100,000 to Mr. Thiede. The contributions awarded to Messrs. Vollmer, Barney, and Thiede represent 15.0%, 28.0%, and 18.9% of their base salaries, respectively.

Employment and Severance Agreements

We typically do not have employment or severance agreements with our executives entitling them to specific payments upon termination of employment or a change of control of the company. The compensation committee generally considers providing severance benefits on a case-by-case basis. Post-employment or change of control benefits available to our executives are addressed within our incentive and retirement plans. Refer to the section entitled "Potential Payments upon Termination or Change of Control."

In connection with the strategic review intended to optimize the value of the construction services segment, in February 2023 the company and MDU Construction Services Group, Inc. entered into a retention agreement with Jeffrey S. Thiede, the current president and chief executive officer of MDU Construction Services Group, Inc., to provide inducement to remain with MDU Construction Services Group, Inc. through the completion of the review and any resulting transaction involving MDU Construction Services Group, Inc. The agreement provides for, among other things, subject to the terms and conditions set forth in the agreement, continuation of Mr. Thiede's then-effective base salary, entitlement to incentive compensation, vesting of company credits to his deferred compensation account, a retention bonus equal to $1,100,000 to be paid within fifteen (15) days after the closing of any transaction, and accelerated vesting of outstanding equity awards as set forth in the agreement. The term of the agreement is until the earlier of the closing of any transaction and December 31, 2023.

In connection with the proposed separation of Knife River Corporation, in February 2023 the company entered into an offer letter with David C. Barney, the former president and chief executive officer of Knife River Corporation, regarding the non-executive position of senior advisor to support the transition of his duties as president and chief executive officer of Knife River Corporation to his successor. The letter agreement provides for, among other things, subject to the terms and conditions set forth in the offer letter, continuation of his 2023 base salary, annual and long-term incentives, and benefits through his retirement on January 3, 2024.

Compensation Governance

Impact of Tax and Accounting Treatment

The compensation committee may consider the impact of tax or accounting treatment in determining compensation. The compensation committee did not make any adjustments to the 2022 compensation program to address the impact of tax or accounting treatment. The compensation committee may also consider the accounting and cash flow implications of various forms of executive compensation. We expense salaries and annual incentive compensation as earned. For our equity awards, we record the accounting expense in accordance with Accounting Standards Codification Topic 718, which is generally expensed over the vesting period.

Stock Ownership Requirements

Executives participating in our Long-Term Performance-Based Incentive Plan are required within five years of appointment or promotion into an executive level position to beneficially own our common stock equal to a multiple of their base salary as outlined in the stock ownership policy. In May 2021, the ownership multiple for our CEO was increased from four times to six times base salary. Stock owned through our 401(k) plan or by a spouse is considered in ownership calculations as well as unvested restricted stock units. The level of stock ownership compared to the ownership requirement is determined based on the closing sale price of our stock on the last trading day of the year and base salary as of December 31 of the same year. The table shows the named executive officers' holdings as a multiple of their base salary.

Name	Ownership Policy Multiple of Base Salary Within 5 Years	Actual Holdings as a Multiple of Base Salary[1]	Ownership Requirement Must Be Met By:
David L. Goodin	6X	11.4	01/01/2018
Jason L. Vollmer	3X	4.3	01/01/2023
David C. Barney	3X	6.4	01/01/2019
Jeffrey S. Thiede	3X	7.4	01/01/2019
Nicole A. Kivisto	3X	6.6	01/01/2020

[1] Includes performance share awards earned net of taxes for the 2020-2022 performance period and unvested restricted stock units granted in February 2021 and 2022.

Incentive Award Clawback Policy

Our Long-Term Performance-Based Incentive Plan and EICP include provisions commonly referred to as a clawback policy. The compensation committee may, or shall if required, take action to recover incentive-based compensation from specific executives in the event the company is required to restate its financial statements due to material noncompliance with any financial reporting requirements under the securities laws.

Policy Regarding Hedging Stock Ownership

Our executive compensation policy prohibits executive officers, which includes our named executive officers, from hedging their ownership of company common stock. Executives may not enter into transactions that allow the executive to benefit from devaluation of our stock or otherwise own stock technically but without the full benefits and risks of such ownership. See the section entitled "Security Ownership" for our policy on margin accounts and pledging of our stock.

COMPENSATION COMMITTEE REPORT

The compensation committee is primarily responsible for reviewing, approving, and overseeing the company's compensation plans and practices and works with management and the committee's independent compensation consultant to develop the company executive compensation programs. The compensation committee has reviewed and discussed the Compensation Discussion and Analysis required by Regulation S-K, Item 402(b), with management. Based on the review and discussions referred to in the preceding sentence, the compensation committee recommended to the board of directors that the Compensation Discussion and Analysis be included in our Proxy Statement on Schedule 14A.

Karen B. Fagg, Chair
German Carmona Alvarez
Thomas Everist
Patricia L. Moss

EXECUTIVE COMPENSATION TABLES

Summary Compensation Table for 2022

Name and Principal Position (a)	Year (b)	Salary ($) (c)	Stock Awards ($) (e)[1]	Non-Equity Incentive Plan Compensation ($) (g)	Change in Pension Value and Nonqualified Deferred Compensation Earnings ($) (h)[2]	All Other Compensation ($) (i)[3]	Total ($) (j)
David L. Goodin	2022	1,044,000	3,247,775	739,935	33,340	192,238	5,257,289
President and CEO	2021	1,000,000	3,222,639	701,250	65,571	221,007	5,210,467
	2020	960,000	2,974,497	1,818,000	484,134	186,779	6,423,410
Jason L. Vollmer	2022	530,000	860,649	225,383	—	150,957	1,766,989
Vice President and CFO	2021	490,000	845,942	206,168	—	122,163	1,664,273
	2020	440,000	654,388	499,950	6,880	105,928	1,707,146
David C. Barney[4]	2022	535,000	868,777	313,377	—	214,491	1,931,645
Former President and CEO of	2021	512,500	884,789	310,191	—	219,420	1,926,900
Knife River Corporation	2020	487,000	725,030	804,646	86,980	220,062	2,323,718
Jeffrey S. Thiede	2022	530,000	860,649	613,343	—	166,470	2,170,462
President and CEO of	2021	507,500	876,148	293,462	—	171,822	1,848,932
MDU Construction	2020	487,000	725,030	852,128	—	170,362	2,234,520
Services Group, Inc.							
Nicole A. Kivisto	2022	530,000	860,649	266,723	1,294	78,795	1,737,461
President and CEO of	2021	507,500	876,148	332,666	2,645	83,272	1,802,231
Montana-Dakota Utilities Co.,	2020	487,000	725,030	436,839	184,058	73,374	1,906,301
Cascade Natural Gas Corporation,							
and Intermountain Gas Company							

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[1] Amounts in this column represent the aggregate grant date fair value of performance share awards at target calculated in accordance with generally accepted accounting principles for stock-based compensation in Accounting Standards Codification Topic 718. This column was prepared assuming none of the awards were or will be forfeited. The amounts were calculated as described in Note 13 of our audited financial statements in our Annual Report on Form 10-K for the year ended December 31, 2022. For 2022, the aggregate grant date fair value of outstanding performance share awards assuming the highest level of payout would be as follows:

Name	Aggregate Grant Date Fair Value at Highest Payout ($)
David L. Goodin	5,767,500
Jason L. Vollmer	1,528,381
David C. Barney	1,542,806
Jeffrey S. Thiede	1,528,381
Nicole A. Kivisto	1,528,381

[2] Amounts shown for 2022 represent the change in the actuarial present value for the named executive officers' accumulated benefits under the pension plan, SISP, and Excess SISP, collectively referred to as the "accumulated pension change," plus above-market earnings on deferred annual incentives as of December 31, 2022. Where the change in accumulated pension benefits is negative, executive compensation rules require the disclosure of the negative amount by footnote but note the negative amount should not be reflected in the sum reported in column (h) of the table.

Name	Accumulated Pension Change ($)	Above Market Earnings ($)
David L. Goodin	(1,048,574)	33,340
Jason L. Vollmer	(14,814)	—
David C. Barney	(262,364)	—
Jeffrey S. Thiede	—	—
Nicole A. Kivisto	(417,732)	1,294

[3] All Other Compensation for 2022 is comprised of:

Name	401(k) Plan ($)[a]	Nonqualified Deferred Compensation Plan ($)[b]	Life Insurance Premium ($)	Matching Charitable Contributions ($)	Dividend Equivalents ($)[c]	Total ($)
David L. Goodin	44,189	—	774	3,600	143,675	192,238
Jason L. Vollmer	30,500	79,500	774	3,600	36,583	150,957
David C. Barney	24,400	150,000	774	1,200	38,117	214,491
Jeffrey S. Thiede	24,400	100,000	774	3,475	37,821	166,470
Nicole A. Kivisto	36,600	—	774	3,600	37,821	78,795

[a] Represents company contributions to the 401(k) plan, which includes matching contributions and retirement contributions associated with the frozen pension plans as of December 31, 2009.

[b] Represents company contribution amounts to the MDU Resources Group, Inc. Deferred Compensation Plan (DCP) which are approved by the compensation committee and the board of directors. The purpose of the plan is to recognize outstanding performance coupled with enhanced retention as the DCP requires a vesting period. For further information, see the section entitled "Nonqualified Deferred Compensation for 2022."

[c] Represents accrued dividend equivalents for 2022 on the 2022-2024, 2021-2023, and 2020-2022 performance share awards associated with financial performance measures and restricted stock units. The 2022-2024 and 2021-2023 performance share awards are presented at target, and the 2020-2022 performance share awards are presented based on the actual achievement of the performance measures.

[4] On February 16, 2023, the company announced that Mr. Barney would cease serving in his position as chief executive officer of Knife River Corporation, the company's construction materials and contracting segment, effective as of March 1, 2023.

Grants of Plan-Based Awards in 2022

		Estimated Future Payouts Under Non-Equity Incentive Plan Awards			Estimated Future Payouts Under Equity Incentive Plan Awards				
Name (a)	Grant Date (b)	Threshold ($) (c)	Target ($) (d)	Maximum ($) (e)	Threshold (#) (f)	Target (#) (g)	Maximum (#) (h)	All Other Stock Awards: Number of Shares of Stock or Units (#) (i)	Grant Date Fair Value of Stock and Option Awards ($) (l)
David L. Goodin	2/17/2022 [1]	326,250	1,305,000	2,610,000					
	2/17/2022 [2]				15,753	78,766	157,532		2,519,724
	2/17/2022 [3]							26,255	728,051
Jason L. Vollmer	2/17/2022 [1]	99,375	397,500	795,000					
	2/17/2022 [2]				4,174	20,873	41,746		667,732
	2/17/2022 [3]							6,957	192,918
David C. Barney	2/17/2022 [1]	100,313	401,250	963,000					
	2/17/2022 [2]				4,214	21,070	42,140		674,029
	2/17/2022 [3]							7,023	194,748
Jeffrey S. Thiede	2/17/2022 [1]	99,375	397,500	954,000					
	2/17/2022 [2]				4,174	20,873	41,746		667,732
	2/17/2022 [3]							6,957	192,918
Nicole A. Kivisto	2/17/2022 [1]	178,875	397,500	795,000					
	2/17/2022 [2]				4,174	20,873	41,746		667,732
	2/17/2022 [3]							6,957	192,918

[1] Annual incentive for 2022 granted pursuant to the MDU Resources Group, Inc. Executive Incentive Compensation Plan.

[2] Performance shares for the 2022-2024 performance period granted pursuant to the MDU Resources Group, Inc. Long-Term Performance-Based Incentive Plan.

[3] Restricted Stock Units for the 2022-2024 period granted pursuant to the MDU Resources Group, Inc. Long-Term Performance-Based Incentive Plan.

Narrative Discussion Relating to the Summary Compensation Table and Grants of Plan-Based Awards Table

Annual Incentive

The compensation committee recommended the 2022 annual cash incentive award for our named executive officers and the board approved these opportunities at its meeting on February 17, 2022. The awards at threshold, target, and maximum are reflected in columns (c), (d), and (e), respectively, of the Grants of Plan-Based Awards Table. The actual amount paid with respect to 2022 performance is reflected in column (g) of the Summary Compensation Table.

As described in the "Annual Cash Incentives" section of the "Compensation Discussion and Analysis," payment of annual cash incentive awards is dependent upon achievement of performance measures; actual payout may range from 0% to 200% of the target except for the construction materials and contracting and construction services segments which may range from 0% to 240%. The DEI modifier adds or deducts up to 5% of the executives' annual incentive target based on the compensation committee's assessment.

All our named executive officers were awarded their annual cash incentives pursuant to the MDU Resources Group, Inc. Executive Incentive Compensation Plan. Under the Executive Incentive Compensation Plan, executives who retire during the year at or after age 65 remain eligible to receive a prorated award, but executives who terminate employment for other reasons are not eligible for an award. The compensation committee generally does not modify the performance measures; however, if in years of unusually adverse or favorable external conditions or other unforeseen significant factors beyond the control of management, the compensation committee may modify the performance measures. In determining the 2022 annual incentive awards, the compensation committee approved adjustments to earnings from continuing operations of $612,000 after-tax for costs incurred associated with mergers and acquisitions at the construction materials and contracting segment and $12.7 million after-tax for costs incurred in connection with the company's intent to separate the construction materials and contracting segment pursuant to a tax-free spinoff and the strategic review to optimize the value of the construction services segment. The compensation committee has full discretion to determine the extent to which goals have been achieved, the payment level, and whether to adjust payment of awards downward based upon individual performance. For further discussion of the specific 2022 incentive plan performance measures and results, see the "Annual Cash Incentives" section in the "Compensation Discussion and Analysis."

Long-Term Incentive

The compensation committee recommended long-term incentive awards for the named executive officers in the form of 75% performance shares and 25% time-vesting restricted stock units, and the board approved the awards at its meeting on February 17, 2022. The portion of the long-term incentive associated with performance shares are presented as the number of performance shares at threshold, target, and maximum in columns (f), (g), and (h) of the Grants of Plan-Based Awards Table. The value of the long-term performance-based incentive based on the aggregate grant date fair value and is included in the amount recorded in column (e) of the Summary Compensation Table and column (l) of the Grant of Plan-Based Awards Table.

Depending on the achievement of the performance measures associated with our 2022-2024 performance period measured as of December 31, 2024, executives will receive from 0% to 200% of the target performance share awards in February 2025. We also will pay dividend equivalents in cash on the number of shares actually vested for the performance period. The dividend equivalents will be paid in February 2025 if and to the extent they vest and at the same time as the performance share awards are settled.

The portion of the long-term incentive associated with time-vesting restricted stock units are presented as the number of units in column (i) of the Grants of Plan-Based Awards Table. The value of the time-vesting restricted stock units is based on the aggregate grant date value and is included in the amount recorded in column (e) of the Summary Compensation Table and column (l) of the Grant of Plan-Based Awards Table.

The 2022-2024 time-vesting restricted stock units will vest on December 31, 2024, if the executives remain employed with the company through the vesting date. Settlement of the restricted stock units and payment of dividend equivalents will occur in February 2025.

Salary and Bonus in Proportion to Total Compensation

The following table shows the proportion of salary and bonus to total compensation as presented in the Summary Compensation Table. Bonuses for purposes of this table and the Summary Compensation Table refer to discretionary payments to executive officers outside of our executive incentive plans as described above. No bonuses were paid to the executive officers in 2022.

Name	Salary ($)	Bonus ($)	Total Compensation ($)	Salary and Bonus as a % of Total Compensation
David L. Goodin	1,044,000	—	5,257,289	19.9%
Jason L. Vollmer	530,000	—	1,766,989	30.0%
David C. Barney	535,000	—	1,931,645	27.7%
Jeffrey S. Thiede	530,000	—	2,170,462	24.4%
Nicole A. Kivisto	530,000	—	1,737,461	30.5%

Outstanding Equity Awards at Fiscal Year-End 2022

	Stock Awards			
Name (a)	Number of Unearned Shares, Units or Other Rights That Have Not Vested (#) (g)[1]	Market or Payout Value of Unearned Shares, Units or Other Rights That Have Not Vested ($) (h)[2]	Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights That Have Not Vested (#) (i)[3]	Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Other Rights That Have Not Vested ($) (j)[2]
David L. Goodin	51,971	1,576,800	238,106	7,224,136
Jason L. Vollmer	13,707	415,870	59,207	1,796,340
David C. Barney	14,083	427,278	62,286	1,889,757
Jeffrey S. Thiede	13,948	423,182	61,882	1,877,500
Nicole A. Kivisto	13,948	423,182	61,882	1,877,500

[1] Below is the breakdown by year of the outstanding restricted stock unit awards:

Name	2020-2022 Award (#)	2021-2023 Award (#)	2022-2024 Award (#)	Total (#)
David L. Goodin	n/a	25,716	26,255	51,971
Jason L. Vollmer	n/a	6,750	6,957	13,707
David C. Barney	n/a	7,060	7,023	14,083
Jeffrey S. Thiede	n/a	6,991	6,957	13,948
Nicole A. Kivisto	n/a	6,991	6,957	13,948

[2] Value based on the number of performance shares and restricted stock units reflected in columns (g) and (i) multiplied by $30.34, the year-end per share closing stock price for 2022.

[3] Below is a breakdown by year of the outstanding performance share awards:

Name	2020-2022 Award (#)	2021-2023 Award (#)	2022-2024 Award (#)	Total (#)
David L. Goodin	82,191	77,149	78,766	238,106
Jason L. Vollmer	18,082	20,252	20,873	59,207
David C. Barney	20,034	21,182	21,070	62,286
Jeffrey S. Thiede	20,034	20,975	20,873	61,882
Nicole A. Kivisto	20,034	20,975	20,873	61,882

Performance shares for the 2020 award are shown at the target level (100%) based on results for the 2020-2022 performance period being between threshold and target.

Performance shares for the 2021 award are shown at the target level (100%) based on results for the first two years of the 2021-2023 performance period being between threshold and target.

Performance shares for the 2022 award are shown at the target level (100%) based on results for the first year of the 2022-2024 performance period being between threshold and target.

While for purposes of the Outstanding Equity Awards at Fiscal Year-End 2022 table, the number of shares and value shown for the 2020-2022 performance period is at 100% of target, the actual results for the performance period certified by the compensation committee and settled on February 16, 2023, was 91.7% of target. For further information, see the "Long-Term Incentives" section of the "Compensation Discussion and Analysis."

Option Exercises and Stock Vested During 2022

Name (a)	Stock Awards Number of Shares Acquired on Vesting (#) (d)[1]	Stock Awards Value Realized on Vesting ($) (e)[2]
David L. Goodin	133,980	4,467,563
Jason L. Vollmer	26,795	893,479
David C. Barney	32,656	1,088,914
Jeffrey S. Thiede	32,656	1,088,914
Nicole A. Kivisto	32,656	1,088,914

[1] Reflects performance shares for the 2019-2021 performance period ended December 31, 2021, which were settled February 17, 2022.

[2] Reflects the value of vested performance shares based on the closing stock price of $30.84 per share upon the vesting of stock on December 31, 2021 and the dividend equivalents paid on the vested shares.

Pension Benefits for 2022

Name (a)	Plan Name (b)	Number of Years Credited Service (#) (c)[1]	Present Value of Accumulated Benefit ($) (d)
David L. Goodin	Pension	26	1,060,191
	Basic SISP	10	2,431,755
	Excess SISP [2]	26	34,871
Jason L. Vollmer	Pension	4	18,862
	Basic SISP [2]	n/a	—
	Excess SISP [2]	n/a	—
David C. Barney	Pension [2]	n/a	—
	Basic SISP	10	1,401,382
	Excess SISP [2]	n/a	—
Jeffrey S. Thiede	Pension [2]	n/a	—
	Basic SISP [2]	n/a	—
	Excess SISP [2]	n/a	—
Nicole A. Kivisto	Pension	14	192,573
	Basic SISP	10	387,572
	Excess SISP [2]	n/a	—

[1] Years of credited service related to the pension plan reflects the years of participation in the plan as of December 31, 2009, when the pension plan was frozen. Years of credited service related to the Basic SISP reflects the years toward full vesting of the benefit which is 10 years. Years of credited service related to Excess SISP reflects the same number of credited years of service as the pension plan.

[2] Messrs. Barney and Thiede do not participate in the pension plans. Messrs. Vollmer and Thiede do not participate in the SISP. Mr. Goodin is the only named executive officer eligible to participate in the Excess SISP.

The amounts shown for the pension plan, Basic SISP, and Excess SISP represent the actuarial present values of the executives' accumulated benefits accrued as of December 31, 2022, calculated using:

- a 4.97% discount rate for the Basic SISP and Excess SISP;
- a 5.04% discount rate for the pension plan;
- the Society of Actuaries Pri-2012 Total Dataset Mortality with Scale MP-2021 (post commencement only); and
- no recognition of pre-retirement mortality.

The actuary assumed a retirement age of 60 for the pension, Basic SISP, and Excess SISP benefits and assumed retirement benefits commence at age 60 for the pension and Excess SISP and age 65 for Basic SISP benefits.

Pension Plan

The MDU Resources Group, Inc. Pension Plan for Non-Bargaining Unit Employees (pension plan) applies to employees hired before 2006 and was amended to cease benefit accruals as of December 31, 2009. The benefits under the pension plan are based on a participant's average annual salary over the 60 consecutive month period where the participant received the highest annual salary between 1999 and 2009. Benefits are paid as straight life annuities for single participants and as actuarially reduced annuities with a survivor benefit for married participants unless they choose otherwise.

Supplemental Income Security Plan

The Supplemental Income Security Plan (SISP), a nonqualified defined benefit retirement plan, was offered to select key managers and executives. SISP benefits are determined by reference to levels defined within the plan. Our compensation committee, after receiving recommendations from our CEO, determined each participant's level within the plan. On February 11, 2016, the SISP was amended to exclude new participants to the plan and freeze current benefit levels for existing participants.

Basic SISP Benefits

Basic SISP is intended to augment the retirement income provided under the pension plans and are payable to the participant or their beneficiary for a period of 15 years. The Basic SISP benefits are subject to a vesting schedule where participants are 100% vested after ten years of participation in the plan.

Participants can elect to receive the Basic SISP as:

- monthly retirement benefits only;
- monthly death benefits paid to a beneficiary only; or
- a combination of retirement and death benefits, where each benefit is reduced proportionately.

Regardless of the election, if the participant dies before the SISP retirement benefit commences, only the SISP death benefit is provided.

Excess SISP Benefits

Excess SISP is an additional retirement benefit relating to Internal Revenue Code limitations on retirement benefits provided under the pension plans. Excess SISP benefits are equal to the difference between the monthly retirement benefits that would have been payable to the participant under the pension plans absent the limitations under the Internal Revenue Code and the actual benefits payable to the participant under the pension plans. Participants are only eligible for the Excess SISP benefits if the participant is fully vested under the pension plan, their employment terminates prior to age 65, and benefits under the pension plan are reduced due to limitations under the Internal Revenue Code on plan compensation.

In 2009, the SISP was amended to limit eligibility for the Excess SISP benefit. Mr. Goodin is the only named executive officer eligible for the Excess SISP benefit. Benefits generally commence six months after the participant's employment terminates and continue to age 65 or until the death of the participant, if prior to age 65.

Both Basic and Excess SISP benefits are forfeited if the participant's employment is terminated for cause.

Nonqualified Deferred Compensation for 2022

Deferred Annual Incentive Compensation

Executives participating in the Executive Incentive Compensation Plan could elect to defer up to 100% of their annual incentive awards which would accrue interest at a rate determined each year based on an average of the Treasury High Quality Market Corporate Bond Yield Curve for the last business day of each month for the twelve month period from October to September. The interest rate in effect for 2022 was 3.06%. Payment of deferred amounts is in accordance with the participant's election either as lump sum or in monthly installments not to exceed 120 months, following termination of employment or beginning in the fifth year following the year the award was earned. In the event of a change of control, all amounts deferred would immediately become payable. For purposes of deferred annual incentive compensation, a change of control is defined as:

- an acquisition during a 12-month period of 30% or more of the total voting power of our stock;
- an acquisition of our stock that, together with stock already held by the acquirer, constitutes more than 50% of the total fair market value or total voting power of our stock;
- replacement of a majority of the members of our board of directors during any 12-month period by directors whose appointment or election is not endorsed by a majority of the members of our board of directors; or
- acquisition of our assets having a gross fair market value at least equal to 40% of the gross fair market value of all of our assets.

The deferred compensation provision of the Executive Incentive Compensation Plan was frozen to new contributions effective January 1, 2021.

Nonqualified Defined Contribution Plan

The company adopted the Nonqualified Defined Contribution Plan, effective January 1, 2012, to provide deferred compensation for a select group of employees. Company contributions to participant accounts were approved by the compensation committee and constitute an unsecured promise of the company to make such payments. Participant accounts capture the hypothetical investment experience based on the participant's elections. Participants may select from a group of investment options including fixed income, balance/asset allocation, and various equity offerings. Contributions made prior to 2017 vest four years after each contribution while contributions made in and after 2017 vest ratably over a three-year period in accordance with the terms of the plan. Participants may elect to receive their vested contributions and investment earnings either in a lump sum or in annual installments over a period of years upon separation from service with the company. Plan benefits become fully vested if the participant dies while actively employed. Benefits are forfeited if the participant's employment is terminated for cause. The Nonqualified Defined Contribution Plan was frozen to new participants and contributions effective January 1, 2021.

MDU Resources Group, Inc. Deferred Compensation Plan

The company adopted the MDU Resources Group, Inc. Deferred Compensation Plan, effective January 1, 2021, to replace the option to defer annual incentive payments available under the Executive Incentive Compensation Plan and company contributions to participants' accounts through the Nonqualified Defined Contribution Plan. Under the MDU Resources Group, Inc. Deferred Compensation Plan, participants can defer up to 80% of base salary and up to 100% of their annual incentive payment. The company provides discretionary credits to select individuals recommended by the CEO and approved by the compensation committee, similar to the prior Nonqualified Defined Contribution Plan. Participants are 100% vested in their contributions of salary and/or annual incentive but vesting of discretionary employer credits occurs ratably over three years. Participants can establish one or more retirement or in-service accounts which capture the hypothetical investment experience based on a suite of investment options similar to the Nonqualified Defined Contribution Plan. Participants may elect to receive their vested contributions and investment earnings either in a lump sum or in annual installments over a period of years upon a qualifying distribution event. Plan benefits become fully vested if the participant dies or becomes disabled while actively employed. Benefits are forfeited if the participant's employment is terminated for cause.

The table below includes individual deferrals of salary and/or annual incentive and company contributions made during 2022 under the MDU Resources Group, Inc. Deferred Compensation Plan. Aggregate earnings and the balance represent the combined participant earnings and participant balances under all three nonqualified plans.

Name (a)	Executive Contributions in Last FY ($) (b)	Registrant Contributions in Last FY ($) (c)	Aggregate Earnings in Last FY ($) (d)	Aggregate Withdrawals/ Distributions ($) (e)	Aggregate Balance at Last FYE ($) (f)
David L. Goodin	—	—	118,713	—	3,939,330
Jason L. Vollmer	31,239	79,500	(70,817)	—	344,408 [1]
David C. Barney	—	150,000	(130,673)	—	1,032,190 [2]
Jeffrey S. Thiede	—	100,000	(216,555)	—	1,258,225 [3]
Nicole A. Kivisto	—	—	4,607	—	152,862

[1] Mr. Vollmer deferred 6% of his base salary and received company credit of $79,500 under the MDU Resources Group, Inc. Deferred Compensation Plan (DCP) for 2022. Mr. Vollmer's balance also includes employer contributions of $49,000 to the DCP for 2021 and $44,000, $40,000, $35,000, and $22,550 for 2020, 2019, 2018, and 2017, respectively to the Nonqualified Defined Contribution Plan. Each of these amounts are reported in column (i) of the Summary Compensation Table for its respective year, where applicable.

[2] Mr. Barney received $150,000 under the MDU Resources Group, Inc. Deferred Compensation Plan for 2022. Mr. Barney's balance also includes contributions of $150,000 to the DCP for 2021 and contributions of $150,000 to the Nonqualified Defined Contribution Plan for each of 2020, 2019, 2018, and 2017. Each of these amounts are reported in column (i) of the Summary Compensation Table for its respective year, where applicable.

[3] Mr. Thiede received $100,000 under the MDU Resources Group, Inc. Deferred Compensation Plan for 2022. Mr. Thiede's balance also includes contributions of $100,000 to the DCP for 2021 and contributions of $100, 000 to the Nonqualified Defined Contribution Plan for each of 2020, 2019, 2018, 2017, and 2016; $150,000 for 2015; $75,000 for 2014; and $33,000 for 2013. Each of these amounts were reported in column (i) of the Summary Compensation Table in the Proxy Statement for its respective year, where applicable.

Potential Payments upon Termination or Change of Control

The Potential Payments upon Termination or Change of Control Table shows the payments and benefits our named executive officers would receive in connection with a variety of employment termination scenarios or upon a change of control. The scenarios include:

- Voluntary or Not for Cause Termination;
- Death;
- Disability;
- Change of Control with Termination; and
- Change of Control without Termination.

For the named executive officers, the information assumes the terminations or the change of control occurred on December 31, 2022.

The table excludes compensation and benefits our named executive officers would earn during their employment with us whether or not a termination or change of control event had occurred. The tables also do not include benefits under plans or arrangements generally available to all salaried employees and that do not discriminate in favor of the named executive officers, such as benefits under our qualified defined benefit pension plan (for employees hired before 2006), accrued vacation pay, continuation of health care benefits, and life insurance benefits. The tables also do not include deferred compensation under our Executive Incentive Compensation Plan, Nonqualified Defined Contribution Plan, or MDU Resources Group, Inc. Deferred Compensation Plan. These amounts are shown and explained in the "Nonqualified Deferred Compensation for 2022" Table.

Compensation

We typically do not have employment or severance agreements with our executives entitling them to specific payments upon termination of employment or a change of control of the company. The compensation committee generally considers providing severance benefits on a case-by-case basis. Any post-employment or change of control benefits available to our executives are addressed within our incentive and retirement plans. Because severance payments are discretionary, no amounts are presented in the tables.

All our named executive officers were granted their 2022 annual incentive award under the Executive Incentive Compensation Plan (EICP) which has no change of control provision in regards to annual incentive compensation other than for deferred compensation. The EICP requires participants to remain employed with the company through the service year to be eligible for a payout unless otherwise determined by the compensation committee for executive officers or employment termination after age 65. All our scenarios assume a termination or change in control event on December 31st. In these scenarios, the named executive officers would be considered employed for the entire performance period and would be eligible to receive their annual incentive award based on the level that the performance measures were achieved. Therefore, no amounts are shown for annual incentives in the tables for our named executive officers, as they would be eligible to receive their annual incentive award with or without a termination or change of control on December 31, 2022.

All named executive officers received their equity share awards under the Long-Term Performance-Based Incentive Plan (LTIP) which consist of performance share awards for the 2020-2022, 2021-2023 and 2022-2024 vesting periods and restricted stock units for the 2021-2023 and 2022-2024 vesting periods.

Upon a change of control (with or without termination), is defined in the LTIP as:

- the acquisition by an individual, entity, or group of 20% or more of our outstanding common stock;
- a majority of our board of directors whose election or nomination was not approved by a majority of the incumbent board members;
- consummation of a merger or similar transaction or sale of all or substantially all of our assets, unless our stockholders immediately prior to the transaction beneficially own more than 60% of the outstanding common stock and voting power of the resulting corporation in substantially the same proportions as before the merger, no person owns 20% or more of the resulting corporation's outstanding common stock or voting power except for any such ownership that existed before the merger and at least a majority of the board of the resulting corporation is comprised of our directors; or
- stockholder approval of our liquidation or dissolution.

As a result, in the case of a change of control (with or without termination) both performance share awards and restricted stock unit awards would be deemed fully earned and vest at their target levels for the named executive officers.

For our performance share awards, if a participant terminates employment for any reason other than a change of control or prior to reaching age 55 with 10 years of service, their performance share awards are forfeited. If a participant terminates employment for any reason other than for cause after reaching age 55 and completing 10 years of service, performance share awards are prorated as follows:

- termination of employment during the first year of the vesting period = equity share awards are forfeited;
- termination of employment during the second year of the vesting period = equity share awards earned are prorated based on the number of months employed during the vesting period; and
- termination of employment during the third year of the vesting period = full amount of any equity share awards earned are received.

Under the scenarios of voluntary or not for cause termination, disability or death, Messrs. Goodin, Barney, and Thiede would receive performance shares as they have each reached age 55 and have 10 or more years of service. The number of performance shares received would be based on the following:

- 2020-2022 performance shares would vest based on the achievement of the performance measure for the period ended December 31, 2022, which was 91.7%;
- 2021-2023 performance shares would be prorated at 24 out of 36 months (2/3) of the vesting period and vest based on the actual achievement of the performance measure for the period ended December 31, 2023. For purposes of the Potential Payments upon Termination or Change of Control Table, the performance achievement for the performance period is shown at target; and
- 2022-2024 performance shares would be forfeited.

Neither Ms. Kivisto nor Mr. Vollmer have reached age 55; therefore, they are not eligible for vesting of performance shares in the event of their termination, death or disability.

Our restricted stock unit award agreement provides that restricted stock unit share awards are forfeited if the participant's employment terminates for situations other than death, disability or before the participant has reached age 55 with 10 years of service. If a participant's employment terminates after reaching age 55 and completing 10 years of service, restricted stock unit share awards are prorated as follows:

- termination of employment during the first year of the vesting period = restricted stock unit awards are forfeited;
- termination of employment during the second year of the vesting period = restricted stock unit awards earned are prorated based on the number of months employed during the vesting period; and
- termination of employment during the third year of the vesting period = full amount of any restricted stock unit awards earned are received.

In situations of death or disability, the restricted stock unit awards earned would be prorated based on the number of full months of employment completed prior to death or disability during the vesting period.

For 2022, our awards include restricted stock units for the 2021-2023 and 2022-2024 vesting periods. In the case of voluntary or not for cause termination, Messrs. Goodin, Barney and Thiede would forfeit their 2022-2024, restricted stock units but receive their 2021-2023 restricted stock units based on a proration of 24 out of 36 months (2/3). Since neither Ms. Kivisto or Mr. Vollmer have reached age 55, in the case of voluntary or not for cause termination, they would forfeit their 2021-2023 and 2022-2024 restricted stock unit awards.

In the case of termination due to death or disability, all our named executive officers would receive 1/3 of the granted shares associated with the 2022-2024 award based on 12 out of 36 months of the vesting period and 2/3 of the granted shares associated with the 2021-2023 award based on 24 out of 36 months of the vesting period.

For purposes of calculating the performance share and restricted stock unit award value shown in the Potential Payments upon Termination or Change of Control Table, the number of vesting shares was multiplied by the average of the high and low stock price for the last market day of the year, which was December 31, 2022. Dividend equivalents based on the number of vesting shares are also included in the amounts presented.

Benefits

Supplemental Income Security Plan

As described in the "Pension Benefits for 2022" section, the Basic SISP provides benefit payments for 15 years commencing at the latter of retirement or age 65. Of the named executive officers, only Messrs. Goodin, Barney, and Ms. Kivisto participate in the Basic SISP benefits and are 100% vested in their benefit.

Under all scenarios except death and change of control without termination, the payment represents the present value of the vested Basic SISP benefit as of December 31, 2022, using the monthly retirement benefit shown in the table below and a discount rate of 4.97%. In the event of death, Messrs. Goodin, Barney, and Ms. Kivisto's beneficiaries would receive monthly death benefit payments for 15 years. The Potential Payments upon Termination or Change of Control Table shows the present value calculations of the monthly death benefit using the 4.97% discount rate.

	Monthly SISP Retirement Payment ($)	Monthly SISP Death Payment ($)
David L. Goodin	23,040	46,080
David C. Barney	10,936	21,872
Nicole A. Kivisto	6,572	13,144

Because the plan requires a participant to be no longer actively employed by the company in order to be eligible for payments, we do not show benefits for the change of control without a termination scenario.

Mr. Goodin is the only named executive officer eligible for the Excess SISP. Benefits generally commence six months after the participant's employment terminates and continue to age 65 or until the death of the participant, if prior to age 65. As explained in the "Pension Benefits for 2022", Excess SISP benefits are equal to the difference between the monthly retirement benefits that would have been payable to the participant under the pension plans absent the limitations under the Internal Revenue Code and the actual benefits payable to the participant under the pension plans. Under all scenarios except death or change of control without termination, the payment represents the present value of the monthly Excess SISP benefit discounted using a rate of 4.97%

Disability

We provide disability benefits to some of our salaried employees equal to 60% of their base salary, subject to a salary limit of $200,000 for officers and $100,000 for other salaried employees. For all eligible employees, disability payments continue until as follows:

Age When Disabled	Benefits Payable
Prior to age 60	To age 65
Ages 60 to 64	60 months
Ages 65-67	To age 70
Age 68 and over	24 months

Disability benefits are reduced for amounts paid as retirement benefits which include pension and SISP benefits. The disability payments in the Potential Payments upon Termination or Change of Control Table reflect the present value of the disability benefits attributable to the additional $100,000 of base salary recognized for executives under our disability program, subject to the 60% limitation, after reduction for amounts that would be paid as retirement benefits. For Messrs. Goodin and Vollmer and Ms. Kivisto, who participate in the pension plan, the amount represents the present value of the disability benefit after reduction for retirement benefits using a discount rate of 5.04%. Because Messrs. Goodin and Barney's retirement benefits are greater than the disability benefit, the amount shown is zero. For Mr. Thiede, who does not participate in the pension plan, the amount represents the present value of the disability benefit without reduction for retirement benefits using the discount rate of 4.97%, which is considered a reasonable rate for purposes of the calculation.

Potential Payments upon Termination or Change of Control Table

Executive Benefits and Payments upon Termination or Change of Control	Voluntary or Not for Cause Termination ($)	Death ($)	Disability ($)	Change of Control (With Termination) ($)	Change of Control (Without Termination) ($)
David L. Goodin					
Compensation:					
Performance Shares	4,131,375	4,131,375	4,131,375	7,640,916	7,640,916
Restricted Stock Units	550,065	823,390	823,390	1,645,042	1,645,042
Benefits and Perquisites:					
Basic SISP	2,423,837	—	2,423,837	2,423,837	—
Excess SISP	34,074	—	34,074	34,074	—
SISP Death Benefits	—	5,862,771	—	—	—
Disability Benefits	—	—	—	—	—
Total	**7,139,351**	**10,817,536**	**7,412,676**	**11,743,869**	**9,285,958**
Jason L. Vollmer					
Compensation:					
Performance Shares	—	—	—	1,896,909	1,896,909
Restricted Stock Units	—	216,805	216,805	433,841	433,841
Benefits and Perquisites:					
Disability Benefits	—	—	726,427	—	—
Total	**—**	**216,805**	**943,232**	**2,330,750**	**2,330,750**
David C. Barney[1]					
Compensation:					
Performance Shares	1,057,846	1,057,846	1,057,846	1,997,160	1,997,160
Restricted Stock Units	151,024	224,134	224,134	445,848	445,848
Benefits and Perquisites:					
Basic SISP	1,391,390	—	1,391,390	1,391,390	—
SISP Death Benefits	—	2,782,780	—	—	—
Disability Benefits	—	—	—	—	—
Total	**2,600,260**	**4,064,760**	**2,673,370**	**3,834,398**	**2,443,008**
Jeffrey S. Thiede					
Compensation:					
Performance Shares	1,053,418	1,053,418	1,053,418	1,984,366	1,984,366
Restricted Stock Units	149,548	221,971	221,971	441,573	441,573
Benefits and Perquisites:					
Disability Benefits	—	—	266,245	—	—
Total	**1,202,966**	**1,275,389**	**1,541,634**	**2,425,939**	**2,425,939**
Nicole A. Kivisto					
Compensation:					
Performance Shares	—	—	—	1,984,366	1,984,366
Restricted Stock Units	—	221,971	221,971	441,573	441,573
Benefits and Perquisites:					
Basic SISP	384,441	—	384,441	384,441	—
SISP Death Benefits	—	1,672,315	—	—	—
Disability Benefits	—	—	532,912	—	—
Total	**384,441**	**1,894,286**	**1,139,324**	**2,810,380**	**2,425,939**

[1] On February 16, 2023, the company announced that Mr. Barney would cease serving in his position as chief executive officer of Knife River Corporation, the company's construction materials and contracting segment, effective as of March 1, 2023.

CEO Pay Ratio Disclosure

As required by Section 953(b) of the Dodd-Frank Wall Street Reform and Consumer Protection Act and Item 402(u) of Regulation S-K, we are providing information regarding the relationship of the annual total compensation of David L. Goodin, our president and chief executive officer, to the annual total compensation of our median employee.

Our employee workforce fluctuates during the year largely depending on the seasonality, number, and size of construction project activity conducted by our businesses. Approximately 59% of our employee workforce is employed under union bargained labor contracts which define compensation and benefits for participants which may include payments made by the company associated with employee participation in union benefit and pension plans.

We identified the median employee by examining the 2022 taxable wage information for all individuals on the company's payroll records as of December 31, 2022, excluding Mr. Goodin. All of the company's employees are located in the United States. We made no adjustments to annualize compensation for individuals employed for only part of the year. We selected taxable wages as reported to the IRS on Form W-2 for 2022 to identify the median employee as it includes substantially all of the compensation for our median employee and provided a reasonably efficient and cost-effective manner for the identification of the median employee. Our median employee works for a subsidiary of our construction materials and contracting segment with compensation consisting of wages, bonus, company 401(k) matching contributions and profit sharing, life insurance premiums, car allowance, and per diem.

Once identified, we categorized the median employee's compensation using the same methodology as the compensation components reported in the Summary Compensation Table. For 2022, the total annual compensation of Mr. Goodin as reported in the Summary Compensation Table included in this Proxy Statement was $5,257,289, and the total annual compensation of our median employee was $96,652. Based on this information, the 2022 ratio of annual total compensation of Mr. Goodin to the median employee was 54 to 1.

Pay Versus Performance

As required by Section 953(a) of the Dodd-Frank Wall Street Reform and Consumer Protection Act and Item 402(v) of Regulation S-K, we are providing information regarding the Compensation Actually Paid (CAP), as defined by SEC rules, to our executives versus company financial performance. The CAP amounts shown in the table below do not reflect the actual amount of compensation earned by or paid to our executives during the applicable year.

					Value of initial fixed $100 investment based on:			
Year[1]	Summary Compensation Table Total Compensation for Principal Executive Officer (PEO)[2] ($)	Compensation Actually Paid to PEO[3] ($)	Average Summary Compensation Table Total Compensation for Non-PEO Named Executive Officers[4] ($)	Average Compensation Actually Paid to non-PEO Named Executive Officers[5] ($)	Total Stockholder Return[6] ($)	Peer Group Total Stockholder Return[7] ($)	Net Income[8] (in thousands) ($)	Company Selected Measure - Earnings per Share[9] ($)
2022	5,257,289	5,644,274	1,901,639	1,998,863	111.98	123.90	367,489	1.81
2021	5,210,467	7,143,972	1,810,584	2,273,834	110.37	128.00	378,131	1.87
2020	6,423,410	5,664,783	2,042,921	1,901,274	91.69	101.04	390,205	1.95

[1] Our PEO for years 2020, 2021 and 2022 was David L. Goodin. Our non-PEO named executive officers (NEO) for 2020, 2021 and 2022 were Jason L. Vollmer, David C. Barney, Jeffrey S. Thiede and Nicole A. Kivisto.

[2] Represents Mr. Goodin's total compensation as shown in the Summary Compensation Table (SCT) for 2020, 2021 and 2022.

[3] To arrive at CAP for Mr. Goodin, total compensation as reported in the SCT was adjusted for the following:

	2022	2021	2020
SCT Total Compensation for the PEO	5,257,289	5,210,467	6,423,410
less: Reported Value of Stock Awards in the SCT[a]	3,247,775	3,222,639	2,974,497
plus: Stock Award Adjustments[a,b]	3,634,760	5,156,144	2,651,451
less: Change in Actuarial Present Value of Defined Benefit and Pension Plans as Reported in the SCT	—	—	435,581
plus: Aggregate Service Cost and Prior Service Costs on Defined Benefit and Pension Plans	—	—	—
CAP for the PEO	5,644,274	7,143,972	5,664,783

[a] Equity compensation grant date fair value for awards with a market condition performance measure are determined by Monte Carlo simulation. The blended volatility term structure ranges are comprised of 50 percent historical volatility and 50 percent implied volatility. Risk-free interest rates were based on U.S. Treasury security rates in effect as of the grant date. Year-end fair values for awards with a market condition performance measure were determined using the same assumptions. Equity compensation grant date and year-end fair value for time-vesting awards and awards with financial performance measures were determined by the closing stock price on the date of grant or year-end, as applicable.

[b] Stock Award Adjustments in determining CAP

Year	Year-end Fair Value of Equity Awards Granted in the Year which are Unvested	Year-over-Year Change in Fair Value of Equity Awards Granted in Prior Years that are Unvested	Fair Value as of Vesting Date of Equity Awards Granted and Vested in the Year	Year-over-Year Change in Fair Value of Equity Award Granted in Prior Years that Vested in the Year	Prior Year-end Fair Value of Equity Awards that Failed to Meet Vesting Conditions in the Year	Value of Dividends or Other Earnings Paid on Equity Awards not Otherwise Reflected in Fair Value or Total Compensation	Total Equity Award Adjustments
2022	3,665,234	(198,017)	—	167,543	—	—	3,634,760
2021	3,586,652	(90,005)	—	1,659,497	—	—	5,156,144
2020	2,402,446	(557,760)	—	806,765	—	—	2,651,451

[4] Represents the average total compensation of our non-PEO named executive officers as shown in the SCT for 2020, 2021 and 2022.

[5] To arrive at the Average CAP for our non-PEO named executive officers, total compensation as reported in the SCT was adjusted for the following:

	2022	2021	2020
Average of SCT Total Compensation for Non-PEO Named Executive Officers	1,901,639	1,810,584	2,042,921
less: Reported Value of Stock Awards in the SCT[a]	862,681	870,757	707,370
plus: Stock Award Adjustments[a,b]	959,905	1,334,007	634,637
less: Change in Actuarial Present Value of Defined Benefit and Pension Plans as Reported in the SCT	—	—	68,914
plus: Aggregate Service Cost and Prior Service Costs on Defined Benefit and Pension Plans	—	—	—
Average CAP for the Non-PEO Named Executive Officers	1,998,863	2,273,834	1,901,274

[a] Equity compensation grant date fair value for awards with a market condition performance measure are determined by Monte Carlo simulation. The blended volatility term structure ranges are comprised of 50 percent historical volatility and 50 percent implied volatility. Risk-free interest rates were based on U.S. Treasury security rates in effect as of the grant date. Year-end fair values for awards with a market condition performance measure were determined using the same assumptions. Equity compensation grant date and year-end fair value for time-vesting awards and awards with financial performance measures were determined by the closing stock price on the date of grant or year-end, as applicable.

[b] Stock Award Adjustments in determining CAP

Year	Year-end Fair Value of Equity Awards Granted in the Year which are Unvested	Year-over-Year Change in Fair Value of Equity Awards Granted in Prior Years that are Unvested	Fair Value as of Vesting Date of Equity Awards Granted and Vested in the Year	Year-over-Year Change in Fair Value of Equity Award Granted in Prior Years that Vested in the Year	Prior Year-end Fair Value of Equity Awards that Failed to Meet Vesting Conditions in the Year	Value of Dividends or Other Earnings Paid on Equity Awards not Otherwise Reflected in Fair Value or Total Compensation	Total Equity Award Adjustments
2022	973,569	(53,505)	—	39,841	—	—	959,905
2021	969,113	(21,403)	—	386,297	—	—	1,334,007
2020	571,330	(129,852)	—	193,159	—	—	634,637

[6] Represents value of $100 invested in company stock on December 31, 2019 as of December 31, 2020, December 31, 2021 and December 31, 2022 assuming dividends are reinvested in company stock at the frequency paid.

[7] Represents the value of $100 invested in the compensation peer group company stock on December 31, 2019 as of December 31.2020,

December 31, 2021 and December 31, 2022 assuming dividends are reinvested in the compensation peer group stock at the frequency paid. Returns of each peer group company are weighted according to the peer group company's market capitalization at the beginning of the period. Our compensation benchmarking peer group companies for 2020, 2021 and 2022 included:

2020	2021	2022
Alliant Energy	Alliant Energy	Alliant Energy
Ameren Corporation	Ameren Corporation	Ameren Corporation
Atmos Energy Corporation	Atmos Energy Corporation	Atmos Energy Corporation
Black Hills Corporation	Black Hills Corporation	Black Hills Corporation
CMS Energy Corporation	CMS Energy Corporation	CMS Energy Corporation
Dycom Industries, Inc.	Dycom Industries, Inc.	Dycom Industries, Inc.
EMCOR Group, Inc.	EMCOR Group, Inc.	EMCOR Group, Inc.
Evergy, Inc.	Evergy, Inc.	Evergy, Inc.
Granite Construction Incorporated	Granite Construction Incorporated	Granite Construction Incorporated
Jacobs Engineering Group Inc.	Jacobs Engineering Group Inc.*	KRB, Inc.
KRB, Inc.	KRB, Inc.	Martin Marietta Materials, Inc.
Martin Marietta Materials, Inc.	Martin Marietta Materials, Inc.	MasTec, Inc.
MasTec, Inc.	MasTec, Inc.	MYR Group, Inc.*
NiSource Inc.	NiSource Inc.	NiSource Inc.
Pinnacle West Capital Corporation	Pinnacle West Capital Corporation	Pinnacle West Capital Corporation
Portland General Electric Company	Portland General Electric Company	Portland General Electric Company
Quanta Services, Inc.	Quanta Services, Inc.	Quanta Services, Inc.
Southwest Gas Holdings, Inc.	Southwest Gas Holdings, Inc.	Southwest Gas Holdings, Inc.
Summit Materials, Inc.	Summit Materials, Inc.	Summit Materials, Inc.
Vulcan Materials Company	Vulcan Materials Company	Vulcan Materials Company
WEC Energy Group, Inc.	WEC Energy Group, Inc.	WEC Energy Group, Inc.

* Jacobs Engineering Group, Inc. was replaced with MYR Group Inc. in 2022 due to size. Total stockholder return for the peer group companies for 12/31/2020, 12/31/2021 and 12/31/2022 were as follows

	12/31/2019	12/31/2020	12/31/2021	12/31/2022
Peer group with Jacobs Engineering Group Inc.	$ 100.00	$ 101.04	$ 128.00	$ 124.22
Peer group with MYR Group, Inc.	$ 100.00	$ 100.01	$ 126.85	$ 123.90

[8] Represents GAAP Net Income reported for the company in 2020, 2021 and 2022.

[9] Earnings per share (EPS) is the performance measure shared by the PEO and non-PEO named executive officers in the annual incentive program. EPS results represent 100% of the PEO and CFO's annual incentive and 20% of the remaining non-PEO named executive officers annual incentive.

2022 Most Important Financial Measures

The financial performance measures identified as the most important measures used by the company to link PEO and non-PEO named executive officer 2022 CAP to company performance are listed below in unranked order each of which is described in more detail in the "Compensation Discussion and Analysis".

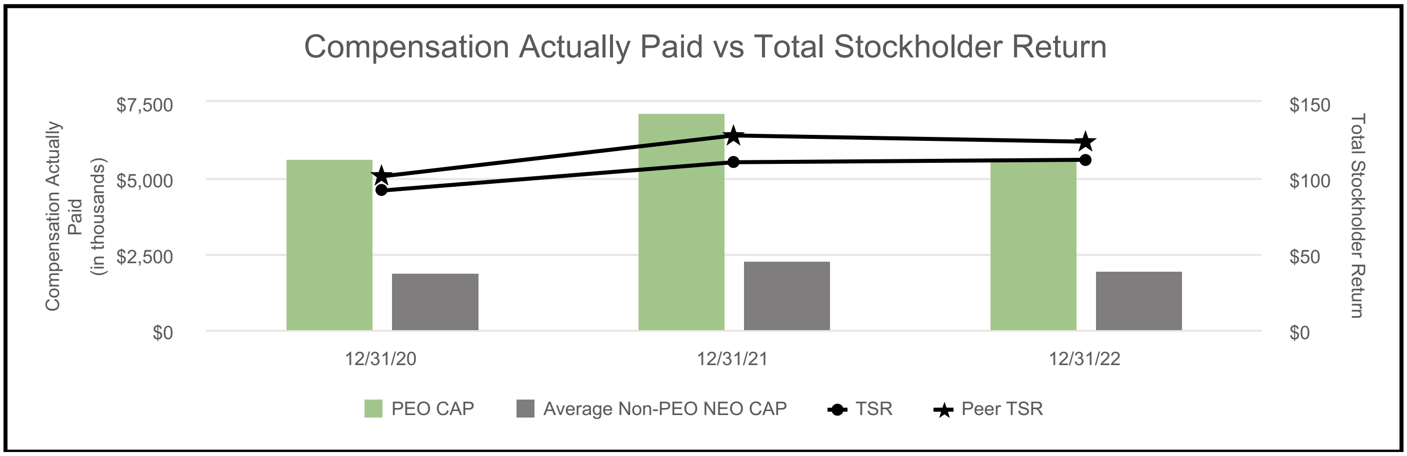
Performance Metrics Most Closely Linked to CAP for 2022
Earnings per Share
Earnings Growth from Continuing Operations
Relative Total Stockholder Return

Descriptions of the Information Presented in the Pay Versus Performance Table

We are providing the following graphics to illustrate the relationship between our PEO CAP and our non-PEO named executive officers' CAP as a group and company performance, as set forth and described in and under the "Pay Versus Performance" table, including the company's cumulative total stockholder return (TSR), net income and EPS. In addition, we are providing a graphic to illustrate the relationship between the company's cumulative TSR and our compensation benchmarking peer group's cumulative TSR.

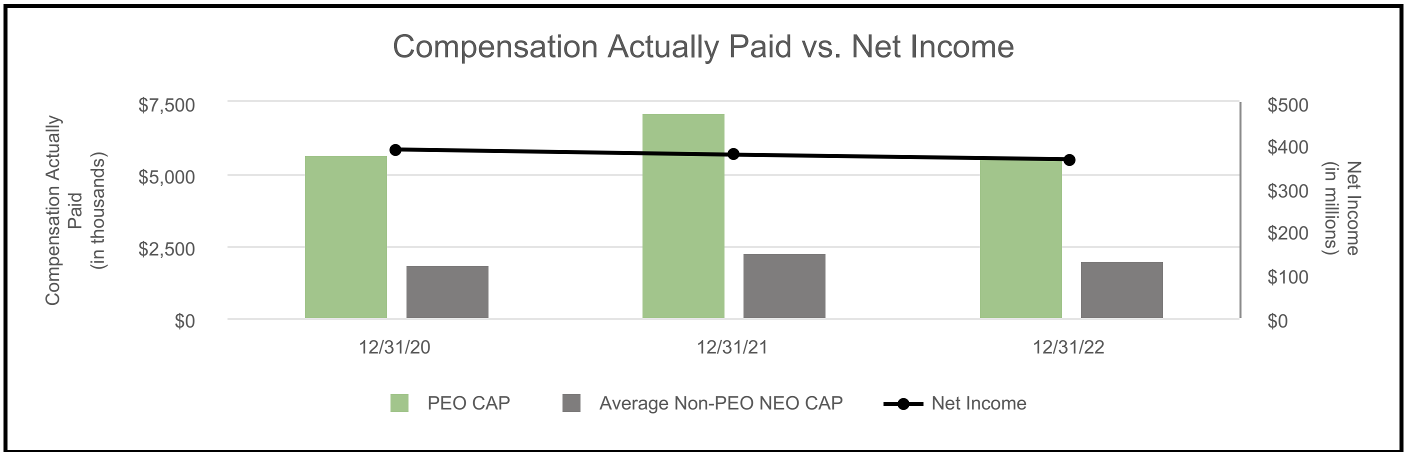
CAP vs. TSR

Our TSR is a reflection of our stock price and dividends paid over a period of time and is important to stockholders as it measures the performance of an investment in our company stock in the marketplace. The following charts depicts the PEO and average non-PEO named executive officer CAP compared to the value of $100 invested in company and peer company stock on December 31, 2019 as of December 31, 2020, December 31, 2021 and December 31, 2022 assuming dividends are reinvested in company stock at the frequency paid.



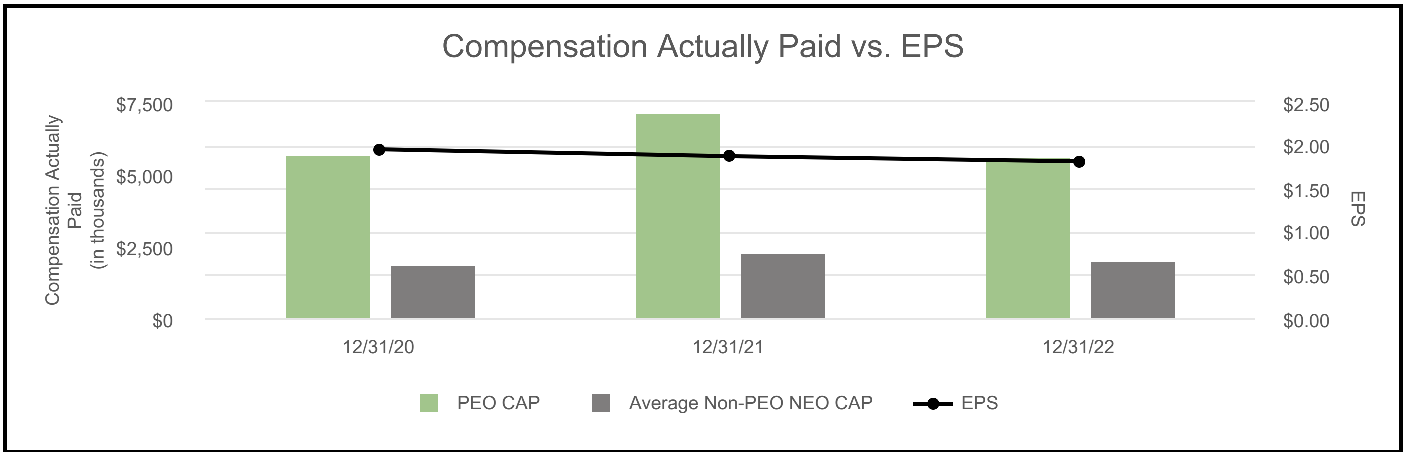
CAP vs. Net Income

The following charts depicts the PEO and average non-PEO NEO CAP compared to the company's net income for 2020, 2021 and 2022.



CAP vs. EPS

The following charts depicts the PEO and average non-PEO named executive officer CAP compared to the company's EPS for 2020, 2021 and 2022.



AUDIT MATTERS

ITEM 4: RATIFICATION OF THE APPOINTMENT OF DELOITTE & TOUCHE LLP AS THE COMPANY'S INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM FOR 2023

The audit committee at its February 2023 meeting appointed Deloitte & Touche LLP as our independent registered public accounting firm for fiscal year 2023. The board of directors concurred with the audit committee's decision. Deloitte & Touche LLP has served as our independent registered public accounting firm since fiscal year 2002.

Although your ratification vote will not affect the appointment or retention of Deloitte & Touche LLP for 2023, the audit committee will consider your vote in determining its appointment of our independent registered public accounting firm for the next fiscal year. The audit committee, in appointing our independent registered public accounting firm, reserves the right, in its sole discretion, to change an appointment at any time during a fiscal year if it determines that such a change would be in our best interests.

A representative of Deloitte & Touche LLP will be present at the annual meeting and will be available to respond to appropriate questions. We do not anticipate that the representative will make a prepared statement at the annual meeting; however, he or she will be free to do so if he or she chooses.

The board of directors recommends a vote "for" the ratification of the appointment of Deloitte & Touche LLP as our independent registered public accounting firm for fiscal year 2023.

Ratification of the appointment of Deloitte & Touche LLP as our independent registered public accounting firm for 2023 requires the affirmative vote of a majority of our common stock present in person or represented by proxy at the annual meeting and entitled to vote on the proposal. Abstentions will count as votes against this proposal.

Annual Evaluation and Selection of Deloitte & Touche LLP

The audit committee annually evaluates the performance of its independent registered public accounting firm, including the senior audit engagement team, and determines whether to re-engage the current independent accounting firm or consider other firms. Factors considered by the audit committee in deciding whether to retain the current independent accounting firm include:

- Deloitte & Touche LLP's capabilities considering the complexity of our business and the resulting demands placed on Deloitte & Touche LLP in terms of technical expertise and knowledge of our industry and business;
- the quality and candor of Deloitte & Touche LLP's communications with the audit committee and management;
- Deloitte & Touche LLP's independence;
- the quality and efficiency of the services provided by Deloitte & Touche LLP, including input from management on Deloitte & Touche LLP's performance and how effectively Deloitte & Touche LLP demonstrated its independent judgment, objectivity, and professional skepticism;
- the workload capacity and resources of Deloitte & Touche LLP's senior audit engagement team;
- external data on audit quality and performance, including recent Public Company Accounting Oversight Board reports on Deloitte & Touche LLP and its peer firms; and
- the appropriateness of Deloitte & Touche LLP's fees, tenure as our independent auditor, including the benefits of a longer tenure, and the controls and processes in place that help ensure Deloitte & Touche LLP's continued independence.

Based on this evaluation, the audit committee and the board believe that retaining Deloitte & Touche LLP to serve as our independent registered public accounting firm for the fiscal year ending December 31, 2023, is in the best interests of our company and its stockholders.

In accordance with rules applicable to mandatory partner rotation, Deloitte & Touche LLP's lead engagement partner for our audit was changed in 2022. The audit committee oversees the process for, and ultimately approves, the selection of the lead engagement partner.

Audit Fees and Non-Audit Fees

The following table summarizes the aggregate fees that our independent registered public accounting firm, Deloitte & Touche LLP, billed or is expected to bill us for professional services rendered for 2021 and 2022:

	2021	2022
Audit Fees [1]	$ 2,910,640	$ 3,160,291
Audit-Related Fees	—	$ 1,319,159 [2]
Tax Fees	—	—
All Other Fees	—	—
Total Fees [3]	$ 2,910,640	$ 4,479,450
Ratio of Tax and All Other Fees to Audit and Audit-Related Fees	0 %	0 %

[1] Audit fees for 2021 and 2022 consisted of fees for the annual audit of our consolidated financial statements and internal control over financial reporting, statutory and regulatory audits, reviews of quarterly financial statements, comfort letters in connection with securities offerings, and other filings with the SEC.

[2] Fees for Knife River Corporation audit in connection with the company's intent to separate Knife River Corporation pursuant to a tax-free spinoff, and other filings with the SEC.

[3] Total fees reported above include out-of-pocket expenses related to the services provided of $100,000 for 2021 and $181,026 for 2022.

Policy on Audit Committee Pre-Approval of Audit and Permissible Non-Audit Services of the Independent Registered Public Accounting Firm

The audit committee pre-approved all services Deloitte & Touche LLP performed in 2022 in accordance with the pre-approval policy and procedures the audit committee adopted in 2003. This policy is designed to achieve the continued independence of Deloitte & Touche LLP and to assist in our compliance with Sections 201 and 202 of the Sarbanes-Oxley Act of 2002 and related rules of the SEC.

The policy defines the permitted services in each of the audit, audit-related, tax, and all other services categories, as well as prohibited services. The pre-approval policy requires management to submit annually for approval to the audit committee a service plan describing the scope of work and anticipated cost associated with each category of service. At each regular audit committee meeting, management reports on services performed by Deloitte & Touche LLP and the fees paid or accrued through the end of the quarter preceding the meeting. Management may submit requests for additional permitted services before the next scheduled audit committee meeting to the designated member of the audit committee, currently David M. Sparby, for approval. The designated member updates the audit committee at the next regularly scheduled meeting regarding any services approved during the interim period. At each regular audit committee meeting, management may submit to the audit committee for approval a supplement to the service plan containing any request for additional permitted services.

In addition, prior to approving any request for audit-related, tax, or all other services of more than $50,000, Deloitte & Touche LLP are required to provide a statement setting forth the reasons why rendering of the proposed services does not compromise Deloitte & Touche LLP's independence. This description and statement by Deloitte & Touche LLP may be incorporated into the service plan or included as an exhibit thereto or may be delivered in a separate written statement.

AUDIT COMMITTEE REPORT

The audit committee assists the board in fulfilling its oversight responsibilities and serves as a communication link among the board, management, the independent auditors, and the internal auditors. The audit committee (a) assists the board's oversight of (i) the integrity of the company's financial reporting process and system of internal controls, (ii) the company's compliance with legal and regulatory requirements and the code of conduct, (iii) the independent auditors' qualifications and independence, (iv) the performance of the company's internal audit function and independent auditors, and (v) the company's management of risks in the audit committee's areas of responsibility; (b) arranges for the preparation of and approves the report that SEC rules require be included in the company's annual proxy statement; and (c) is also responsible for the appointment, compensation, retention, and oversight of the independent auditors including pre-approval of all audit and non-audit services by the independent auditors. The audit committee acts under a written charter which it reviews at least annually and a copy of which is available on our website.

Management has primary responsibility for the company's financial statements and the reporting process, including the systems of internal control over financial reporting. The independent auditors are responsible for performing an independent audit of the company's consolidated financial statements, issuing an opinion on the conformity of those audited financial statements with generally accepted accounting principles, and assessing the effectiveness of the company's internal controls over financial reporting. The audit committee oversees the company's financial reporting process and internal controls on behalf of the board.

In performing its oversight responsibilities in connection with our financial statements for the year ended December 31, 2022, the audit committee:

- reviewed and discussed the audited financial statements with management;
- discussed with the independent auditors the matters required to be discussed by the applicable requirements of the Public Company Accounting Oversight Board and the SEC; and
- received the written disclosures and the letter from the independent auditors required by applicable requirements of the Public Company Accounting Oversight Board regarding the independent auditors' communications with the audit committee concerning independence and discussed with the independent auditors their independence.

Based on the review and discussions referred to above, the audit committee recommended to the board of directors, and the board of directors has approved, that the audited financial statements be included in our Annual Report on Form 10-K for the year ended December 31, 2022, for filing with the SEC. The audit committee has appointed Deloitte & Touche LLP as the company's independent auditors for 2023. Stockholder ratification of this appointment is included as Item 4 in these proxy materials.

David M. Sparby, Chair

Dale S. Rosenthal

Edward A. Ryan

Chenxi Wang

INFORMATION ABOUT THE ANNUAL MEETING

Who Can Vote?

Stockholders of record at the close of business on March 10, 2023, are entitled to vote each share they owned on that date on each matter presented at the meeting and any adjournment(s) thereof. As of March 10, 2023, we had 203,623,893 shares of common stock outstanding each entitled to one vote per share.

Distribution of Our Proxy Materials Using Notice and Access

We distributed proxy materials to certain of our stockholders via the Internet under the SEC's "Notice and Access" rules to reduce our costs and decrease the environmental impact of our proxy materials. Using this method of distribution, on or about March 24, 2023, we mailed a Notice Regarding the Availability of Proxy Materials (Notice) that contains basic information about our 2023 annual meeting and instructions on how to view all proxy materials, and vote electronically, on the Internet. If you received the Notice and prefer to receive a paper copy of the proxy materials, follow the instructions in the Notice for making this request and the materials will be sent promptly to you via your preferred method.

How to Vote

You are encouraged to vote in advance of the meeting using one of the following voting methods, even if you are planning to attend the 2023 Annual Meeting of Stockholders.

Registered Stockholders: Stockholders of record who hold their shares directly with our stock registrar can vote any one of four ways:

By Internet: Go to the website shown on the Notice or Proxy Card, if you received one, and follow the instructions.

By Telephone: Call the telephone number shown on the Notice or Proxy Card, if you received one, and follow the instructions given by the voice prompts.

Voting via the Internet or by telephone authorizes the named proxies to vote your shares in the same manner as if you marked, signed, dated, and returned the Proxy Card by mail. Your voting instructions may be transmitted up until 11:59 p.m. Eastern Time on May 8, 2023.

By Mail: If you received a paper copy of the Proxy Statement, Annual Report, and Proxy Card, mark, sign, date, and return the Proxy Card in the postage-paid envelope provided.

In Person: Attend the annual meeting, or send a personal representative with an appropriate proxy, to vote by ballot at the meeting.

Beneficial Stockholders: Stockholders whose shares are held beneficially in the name of a bank, broker, or other holder of record (sometimes referred to as holding shares "in street name"), will receive voting instructions from said bank, broker, or other holder of record. **If you wish to vote in person at the meeting, you must obtain a legal proxy from your bank, broker, or other holder of record of your shares and present it at the meeting.**

See discussion below regarding the MDU Resources Group, Inc. 401(k) Plan for voting instructions for shares held under our 401(k) plan.

Revoking Your Proxy or Changing Your Vote

You may change your vote at any time before the proxy is exercised.

Registered Stockholders:

- *If you voted by mail*: you may revoke your proxy by executing and delivering a timely and valid later dated proxy, by voting by ballot at the meeting, or by giving written notice of revocation to the corporate secretary.
- *If you voted via the Internet or by telephone*: you may change your vote with a timely and valid later Internet or telephone vote, as the case may be, or by voting by ballot at the meeting.
- Attendance at the meeting will not have the effect of revoking a proxy unless (1) you give proper written notice of revocation to the corporate secretary before the proxy is exercised, or (2) you vote by ballot at the meeting.

Beneficial Stockholders: Follow the specific directions provided by your bank, broker, or other holder of record to change or revoke any voting instructions you have already provided. Alternatively, you may vote your shares by ballot at the meeting if you obtain a legal proxy from your bank, broker, or other holder of record and present it at the meeting.

Discretionary Voting Authority

If you complete and submit your proxy voting instructions, the individuals named as proxies will follow your instructions. If you are a stockholder of record and you submit proxy voting instructions but do not direct how to vote on each item, the individuals named as proxies will vote as the board recommends on each proposal. The individuals named as proxies will vote on any other matters properly presented at the annual meeting in accordance with their discretion. Our bylaws set forth requirements for advance notice of any nominations or agenda items to be brought up for voting at the annual meeting, and we have not received timely notice of any such matters, other than the items from the board of directors described in this Proxy Statement.

Voting Standards

A majority of outstanding shares of stock entitled to vote must be present in person or represented by proxy to hold the meeting. Abstentions and broker non-votes are counted for purposes of determining whether a quorum is present at the annual meeting.

If you are a beneficial holder and do not provide specific voting instruction to your broker, the organization that holds your shares will not be authorized to vote your shares, which would result in broker non-votes, on proposals other than the ratification of the selection of our independent registered public accounting firm for 2023.

The following chart describes the proposals to be considered at the annual meeting, the vote required to elect directors and to adopt each other proposal, and the manner in which votes will be counted:

Item No.	Proposal	Voting Options	Vote Required to Adopt the Proposal	Effect of Abstentions	Effect of "Broker Non-Votes"
1	Election of Directors	For, against, or abstain on each nominee	A nominee for director will be elected if the votes cast for such nominee exceed the votes cast against such nominee.	No effect	No effect
2	Advisory Vote to Approve the Frequency of Future Advisory Votes to Approve the Compensation Paid to the Company's Named Executive Officers	1 year, 2 years, 3 years, or abstain	The frequency that receives the most votes will be deemed the frequency recommended by our stockholders	No effect	No effect
3	Advisory Vote to Approve the Compensation Paid to the Company's Named Executive Officers	For, against, or abstain	The affirmative vote of a majority of the shares of common stock represented at the annual meeting and entitled to vote thereon	Same effect as votes against	No effect
4	Ratification of the Appointment of Deloitte & Touche LLP as the Company's Independent Registered Public Accounting Firm for 2023	For, against, or abstain	The affirmative vote of a majority of the shares of common stock represented at the annual meeting and entitled to vote thereon	Same effect as votes against	Brokers have discretion to vote

Proxy Solicitation

The board of directors is furnishing proxy materials to solicit proxies for use at the Annual Meeting of Stockholders on May 9, 2023, and any adjournment(s) thereof. Proxies are solicited principally by mail, but directors, officers, and employees of MDU Resources Group, Inc. or its subsidiaries may solicit proxies personally, by telephone, or by electronic media, without compensation other than their regular compensation. Okapi Partners, LLC, additionally will solicit proxies for approximately $9,500 plus out-of-pocket expenses. We will pay the cost of soliciting proxies and will reimburse brokers and others for forwarding proxy materials to stockholders.

Electronic Delivery of Proxy Statement and Annual Report Documents

For stockholders receiving proxy materials by mail, you can elect to receive an email in the future that will provide electronic links to these documents. Opting to receive your proxy materials online will save the company the cost of producing and mailing documents to your home or business and will also give you an electronic link to the proxy voting site.

- **Registered Stockholders:** If you vote on the Internet, simply follow the prompts for enrolling in the electronic proxy delivery service. You may also enroll in the electronic proxy delivery service at any time in the future by going directly to http://enroll.icsdelivery.com/mdu to request electronic delivery. You may revoke an electronic delivery election at this site at any time.
- **Beneficial Stockholders:** If you hold your shares in a brokerage account, you may also have the opportunity to receive copies of the proxy materials electronically. You may enroll in the electronic proxy delivery service at any time by going directly to http://enroll.icsdelivery.com/mdu to request electronic delivery. You may also revoke an electronic delivery election at this site at any time. In addition, you may also check the information provided in the proxy materials mailed to you by your bank or broker regarding the availability of this service or contact your bank or broker to request electronic delivery.

Householding of Proxy Materials

In accordance with a Notice sent to eligible stockholders who share a single address, we are sending only one Annual Report to Stockholders and one Proxy Statement to that address unless we received instructions to the contrary from any stockholder at that address. This practice, known as “householding,” is designed to reduce our printing and postage costs. However, if a stockholder of record wishes to receive a separate Annual Report to Stockholders and Proxy Statement in the future, he or she may contact the Office of the Treasurer at MDU Resources Group, Inc., P.O. Box 5650, Bismarck, ND 58506-5650, Telephone Number: (701) 530-1000. Eligible stockholders of record who receive multiple copies of our Annual Report to Stockholders and Proxy Statement can request householding by contacting us in the same manner. Stockholders who own shares through a bank, broker, or other nominee can request householding by contacting the nominee.

We will promptly deliver, upon written or oral request, a separate copy of the Annual Report to Stockholders and Proxy Statement to a stockholder at a shared address to which a single copy of the document was delivered.

MDU Resources Group, Inc. 401(k) Plan

This Proxy Statement is being used to solicit voting instructions from participants in the MDU Resources Group, Inc. 401(k) Plan with respect to shares of our common stock that are held by the trustee of the plan for the benefit of plan participants. If you are a plan participant and also own other shares as a registered stockholder or beneficial owner, you will separately receive a Notice or proxy materials to vote those other shares you hold outside of the MDU Resources Group, Inc. 401(k) Plan. If you are a plan participant, you must instruct the plan trustee to vote your shares by utilizing one of the methods described on the voting instruction form that you receive in connection with shares held in the plan. If you do not give voting instructions, the trustee generally will vote the shares allocated to your personal account in accordance with the recommendations of the board of directors. Your voting instructions may be transmitted up until 11:59 p.m. Eastern Time on May 4, 2023.

Annual Meeting Admission and Guidelines

Admission: All stockholders as of the record date of March 10, 2023, are cordially invited to attend the annual meeting. **You must request an admission ticket to attend.** If you are a stockholder of record and plan to attend the meeting, please contact MDU Resources by email at CorporateSecretary@mduresources.com or by telephone at 701-530-1010 to request an admission ticket. A ticket will be sent to you by mail.

If your shares are held beneficially in the name of a bank, broker, or other holder of record, and you plan to attend the annual meeting, you will need to submit a written request for an admission ticket by mail to: Investor Relations, MDU Resources Group, Inc., P.O. Box 5650, Bismarck, ND 58506 or email at CorporateSecretary@mduresources.com. The request must include proof of stock ownership as of March 10, 2023, such as a bank or brokerage firm account statement or a legal proxy from the bank, broker, or other holder of record confirming ownership. A ticket will be sent to you by mail.

Requests for admission tickets must be received no later than May 2, 2023. You must present your admission ticket and state-issued photo identification, such as a driver’s license, to gain admittance to the meeting.

Guidelines: The use of cameras or sound recording equipment is prohibited except by the media or those employed by the company to provide a record of the proceedings. The use of cell phones and other personal communication devices is also prohibited during the meeting. All devices must be turned off or muted. No firearms or weapons, banners, packages, or signs will be allowed in the meeting room. MDU Resources Group, Inc. reserves the right to inspect all items, including handbags and briefcases, that enter the meeting room.

Conduct of the Meeting

Neither the board of directors nor management intends to bring before the meeting any business other than the matters referred to in the Notice of Annual Meeting and this Proxy Statement. We have not been informed that any other matter will be presented at the meeting by others. However, if any other matters are properly brought before the annual meeting, or any adjournment(s) thereof, your proxies include discretionary authority for the persons named in the proxy to vote or act on such matters in their discretion.

Stockholder Proposals, Director Nominations, and Other Items of Business for 2024 Annual Meeting

Stockholder Proposals for Inclusion in Next Year's Proxy Statement: To be included in the proxy materials for our 2024 annual meeting, a stockholder proposal must be received by the corporate secretary no later than November 24, 2023, unless the date of the 2024 annual meeting is more than 30 days before or after May 9, 2024, in which case the proposal must be received a reasonable time before we begin to print and mail our proxy materials. The proposal must also comply with all applicable requirements of Rule 14a-8 under the Securities Exchange Act of 1934.

Director Nominations From Stockholders for Inclusion in Next Year's Proxy Statement: If a stockholder or group of stockholders wishes to nominate one or more director candidates to be included in our proxy statement for the 2024 annual meeting through our proxy access bylaw provision, we must receive proper written notice of the nomination not later than 120 days or earlier than 150 days before the anniversary date that the definitive proxy statement was first released to stockholders in connection with the annual meeting, or between October 26, 2023 and November 24, 2023. In the event that the 2024 annual meeting is more than 30 days before or after May 9, 2024, the notice must be delivered no earlier than the 150th day prior to such meeting and no later than the 120th day prior to such meeting or the 10th day following the date on which public announcement of the meeting date is first made. The requirements of such notice can be found in our bylaws, a copy of which is on our website, at https://investor.mdu.com/governance/governance-documents. In addition, Rule 14a-19 under the Exchange Act requires additional information be included in director nomination notices, including a statement that the stockholder intends to solicit the holders of shares representing at least 67% of the voting power of shares entitled to vote on the election of directors. If any change occurs with respect to such stockholder's intent to solicit the holders of shares representing at least 67% of such voting power, such stockholder must notify us promptly.

Director Nominations and Other Stockholder Proposals Raised From the Floor at the 2024 Annual Meeting of Stockholders: Under our bylaws, if a stockholder intends to nominate a person as a director, or present other items of business at an annual meeting, the stockholder must provide written notice of the director nomination or stockholder proposal not earlier than the 120th day prior to the first anniversary of the preceding year's annual meeting of stockholders and not later than the close of business of the 90th day prior to the first anniversary of the preceding year's annual meeting of stockholders. Notice of director nominations or stockholder proposals for our 2024 annual meeting must be received between January 10, 2024 and February 9, 2024, and meet all the requirements and contain all the information, including the completed questionnaire for director nominations, provided by our bylaws. The requirements for such notice can be found in our bylaws, a copy of which is on our website, at https://investor.mdu.com/governance/governance-documents.

We will make available to our stockholders to whom we furnish this Proxy Statement a copy of our Annual Report on Form 10-K, excluding exhibits, for the year ended December 31, 2022, which is required to be filed with the SEC. You may obtain a copy, without charge, upon written or oral request to the Office of the Treasurer of MDU Resources Group, Inc., 1200 West Century Avenue, Mailing Address: P.O. Box 5650, Bismarck, North Dakota 58506-5650, Telephone Number: (701) 530-1000. You may also access our Annual Report on Form 10-K through our website at www.mdu.com.

By order of the Board of Directors,

Karl A. Liepitz
Secretary
March 24, 2023

Stockholder Information

Corporate Headquarters

Street Address:
1200 W. Century Ave.
Bismarck, ND 58503

Mailing Address:
P.O. Box 5650
Bismarck, ND 58506-5650

Telephone: 701-530-1000
Toll-Free Telephone: 866-760-4852
www.mdu.com

The company has filed as exhibits to its Annual Report on Form 10-K the CEO and CFO certifications as required by Section 302 of the Sarbanes-Oxley Act.

Common Stock

MDU Resources' common stock is listed on the New York Stock Exchange under the symbol MDU. The stock began trading on the NYSE in 1948 and is included in the Standard & Poor's MidCap 400 and the S&P High-Yield Dividend Aristocrats indices. Average daily trading volume in 2022 was 1,295,188 shares.

Shareowner Service Plus Plan

The Shareowner Service Plus Plan provides interested investors the opportunity to purchase shares of MDU Resources' common stock and to reinvest all or a percentage of dividends without incurring brokerage commissions or service charges. The plan is sponsored and administered by Equiniti Trust Company, transfer agent and registrar for MDU Resources. For more information, contact Equiniti Trust Company at 877-536-3553 or visit www.shareowneronline.com.

2023 Key Dividend Dates

	Ex-Dividend Date	Record Date	Payment Date
First Quarter	March 8	March 9	April 1
Second Quarter	June 7	June 8	July 1
Third Quarter	September 13	September 14	October 1
Fourth Quarter	December 13	December 14	January 1, 2024

Key dividend dates are subject to the discretion of the Board of Directors.

Annual Meeting

11 a.m. CDT May 9, 2023
Montana-Dakota Utilities Co. Service Center
909 Airport Road
Bismarck, North Dakota

Shareholder Information and Inquiries

Registered shareholders have electronic access to their accounts by visiting www.shareowneronline.com. Shareowner Online allows shareholders to view their account balance, dividend information, reinvestment details and more. The stock transfer agent maintains stockholder account information.

Communications regarding stock transfer requirements, lost certificates, dividends or change of address should be directed to the stock transfer agent.

Company information, including financial reports, is available at www.mdu.com and investor.mdu.com.

Shareholder and Analyst Contact

Brent L. Miller
Telephone: 866-866-8919 or 701-530-1730
Email: Brent.Miller@MDUResources.com

Transfer Agent and Registrar for All Classes of Stock

Equiniti Trust Company
Stock Transfer Department
P.O. Box 64874
St. Paul, MN 55164-0874
Telephone: 877-536-3553
www.shareowneronline.com

Independent Registered Public Accounting Firm

Deloitte & Touche LLP
50 S. Sixth St., Suite 2800
Minneapolis, MN 55402-1538

Note: This information is not given in connection with any sale or offer for sale or offer to buy any security.

Design: MDU Resources
Printing: AFPI

Trading Symbol: MDU
www.mdu.com

MDU
LISTED
NYSE

Street Address
1200 W. Century Ave.
Bismarck, ND 58503

Mailing Address
P.O. Box 5650
Bismarck, ND 58506-5650

701-530-1000
866-760-4852

Wolfe Research Conference

MDU RESOURCES
GROUP, INC.

December 2023

MDU
LISTED
NYSE

FORWARD-LOOKING STATEMENTS

During the course of this presentation, we will make certain "forward-looking statements" within the meaning of Section 21E of the Securities Exchange Act of 1934. Although the company believes that its expectations and beliefs are based on reasonable assumptions, actual results may differ materially.

For a discussion of factors that may cause actual results to differ, refer to Item 1A – Risk Factors in the company's most recent Form 10-K and Form 10-Q.

MDU RESOURCES GROUP, INC.

Our Vision: With integrity, Building a Strong America® while being a great and safe place to work.

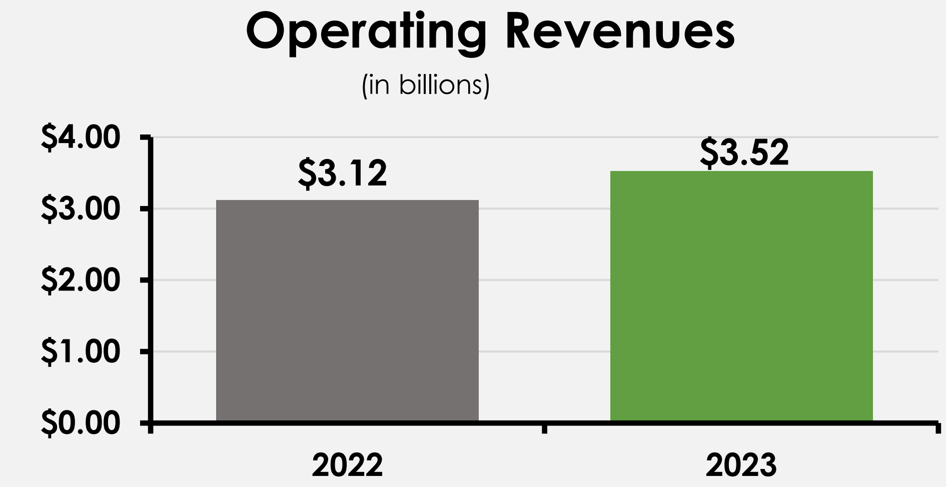
Our Mission: Deliver superior value to stakeholders by providing essential infrastructure and services to America.

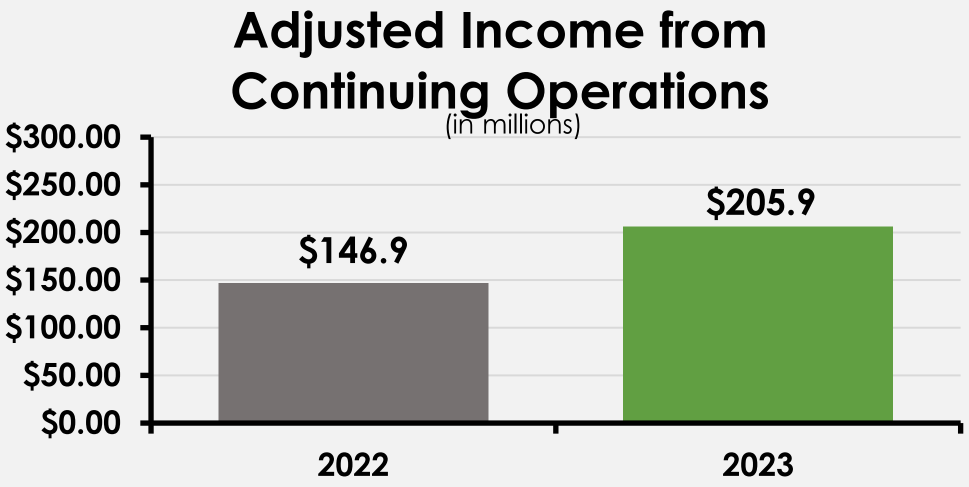
Our Values:

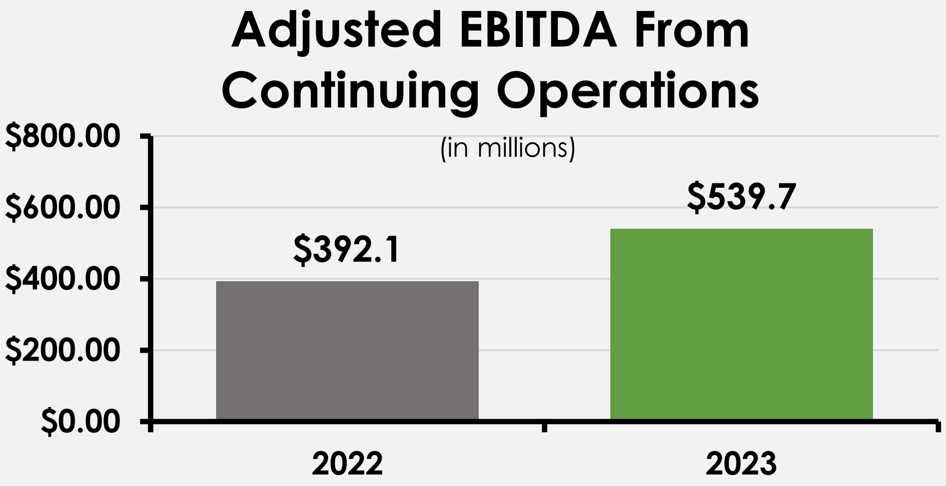
- INTEGRITY
- DIVERSITY
- SAFETY
- INCLUSION
- INNOVATION
- RESPECT
- EXCELLENCE
- STEWARDSHIP

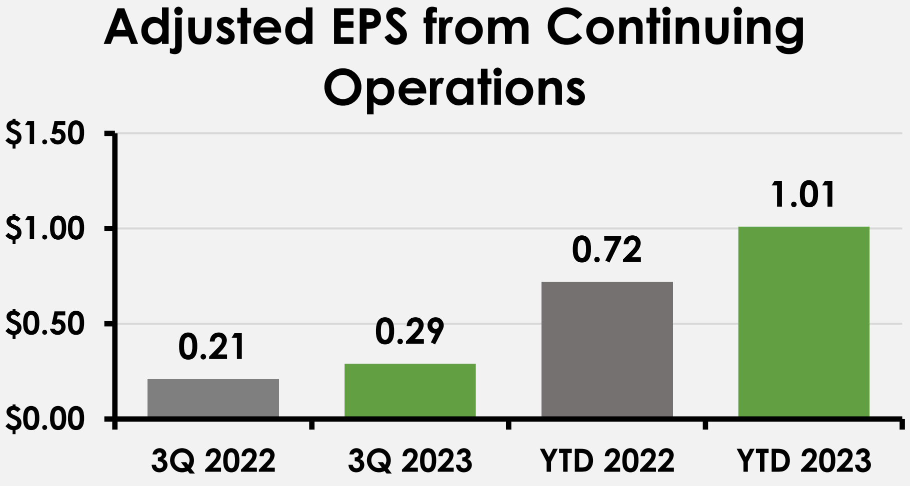
KEY PERFORMANCE INDICATORS

YTD AS OF SEPTEMBER 30, 2023









2023 GUIDANCE

❑ Regulated Energy Delivery Businesses

- ❖ Earnings in the range of $155 million to $165 million

❑ Construction Services

- ❖ Revenues expected to be in the range of $2.80 billion to $3.00 billion in 2023, with slightly higher margins compared to 2022

- ❖ EBITDA in the range of $210 million to $230 million

Guidance as of November 2, 2023

2024-2028 CAPITAL INVESTMENT PLAN

($ in millions)

	Capital Expenditures					
	Forecast				Actual + 2023 Forecast	Forecast
	2023	2024	2025	2026	2019-2023	2024-2028
Regulated Energy Delivery						
Electric	$102	$113	$154	$199	$532	$880
Natural Gas Distribution	$256	$337	$301	$288	$1,066	$1,423
Pipeline	$134	$107	$77	$42	$564	$405
	$492	$557	$532	$529	$2,162	$2,708
Construction Services[1]	$38	$52	$0	$0	$248	$52
Total[2]	**$530**	**$609**	**$532**	**$529**	**$2,410**	**$2,760**

1. Assumes proposed tax-free spinoff completed in late 2024
2. Excludes "Other" category, as well as assumed net proceeds from the sale or disposition of property

LEADERSHIP TRANSITION

DAVID GOODIN

- Has been with MDU Resources for 40 years and has served as CEO for 10 years
- Previously served as President and CEO for Cascade Natural Gas, Great Plains Natural Gas, Intermountain Gas and Montana-Dakota Utilities
- Announced intent to retire, effective Jan. 5, 2024

NICOLE KIVISTO

- Has been with MDU Resources for 28 years and has served as CEO of the utility business for 8 years
- Previously served as Vice President of operations of Great Plains Natural Gas and Montana-Dakota Utilities
- Will succeed Goodin as president and CEO of MDU Resources Group, Inc. effective Jan. 6, 2024

Spinoff Overview

MDU RESOURCES
GROUP, INC.

MDU
LISTED
NYSE

ANNOUNCED PLAN TO SPIN OFF CONSTRUCTION SERVICES BUSINESS

- MDU Resources' Board of Directors approved a plan to spin off MDU Construction Services Group from the Company
  - Spinoff will result in two independent, publicly traded companies
  - Expected to be effected as a tax-free spinoff to MDU shareholders
  - Completion expected in late 2024

STRATEGIC RATIONALE

Heightened strategic focus to pursue individualized strategies specific to the industries in which each company operates

Optimized capital structures and distinct financial policies tailored to their separate business profiles and needs

Tailored capital allocation strategies with enhanced flexibility to deploy capital toward its specific growth opportunities

Distinct investment opportunities that allow investors the ability to better assess the value of the two companies based on their respective operational and financial characteristics

CREATING TWO PUBLICLY TRADED COMPANIES

MDU RESOURCES
GROUP, INC.

MDU®
CONSTRUCTION SERVICES GROUP

- **1.2M** utility customers across **eight states**.
- **3,800 miles** of regulated natural gas transmission pipeline with capacity of **2.5 billion cubic feet per day**.
- **30,100 miles** of electric and natural gas utility transmission and distribution lines.
- **648 MW** of generating capacity.
- Expected earnings of **$155 million** to **$165 million** in 2023.
- **Highest J.D. Power customer satisfaction ranking** among residential natural gas customers in the West Region midsize utilites segment.

- **4th largest** electrical construction contractor in the U.S. (EC&M 2023 Top 50 list).
- **10th largest** specialty contractor in the U.S. (ENR 2023 Top 600 Specialty Contractors list).
- **9,000+ employees** at peak construction season.
- Locations in **19 states**.
- Authorized to work in **43 states** and the **District of Columbia**.
- Expecting revenue of **$2.8 billion** to **$3.0 billion** in 2023, with higher margins compared to 2022.
- Expecting EBITDA of **$210 million** to **$230 million** in 2023.

TRANSACTION DETAILS

Transaction Structure

- Planned as a spinoff that is tax-free to MDU Resources shareholders
- Upon completion of the spinoff, MDU Resources shareholders will retain current shares of MDU Resources stock and receive a pro-rata distribution of shares of MDU Construction Services Group stock

Timing

Expected to be completed in late 2024, subject to customary conditions, including:

- Final approval by the Company's Board of Directors
- Receipt of a tax opinion and, if determined advisable, private letter ruling from the IRS
- Filing and effectiveness of a Form 10 registration statement with the SEC

Commitments

- Establishing strong capital allocation strategies for each business that align with each business's long-term goals
- Post-spinoff, MDU Resources intends to maintain a long-term dividend payout ratio target of 60-70% of regulated energy delivery earnings; MDU Construction Services Group's dividend policy will be determined in the future in a manner consistent with its stated capital allocation strategies

SEGMENT OVERVIEW

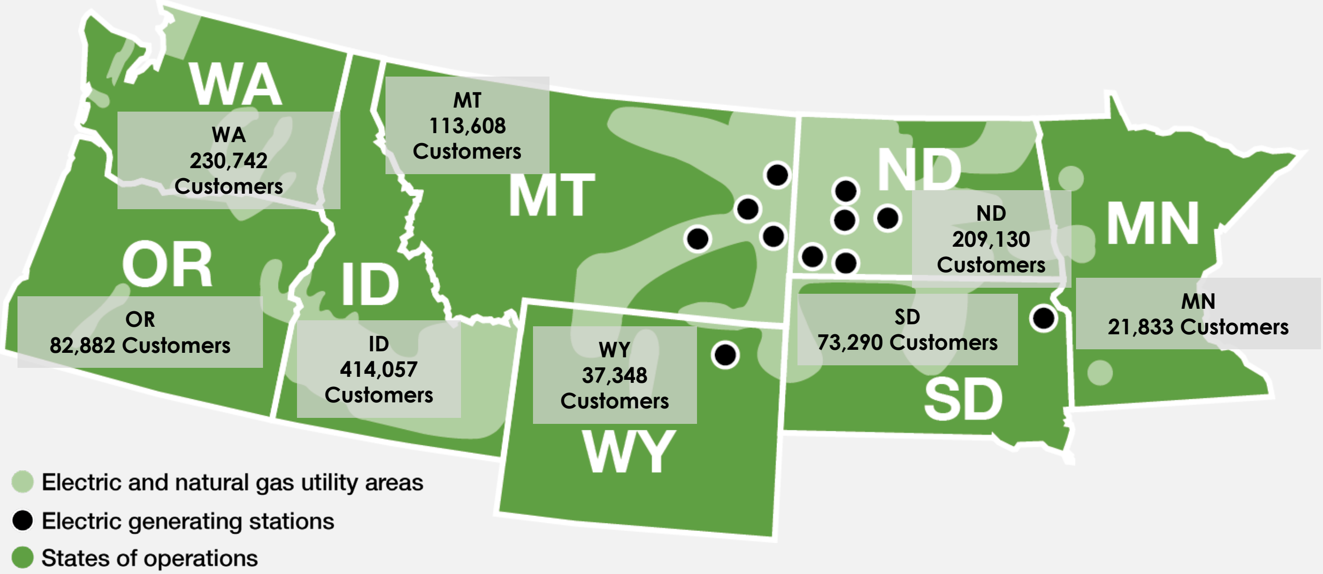
ELECTRIC AND NATURAL GAS SNAPSHOT

1,182,890
(Electric–145,166, Gas – 1,037,724)
Customers
As of 9.30.23

648 MW
Owned Generation

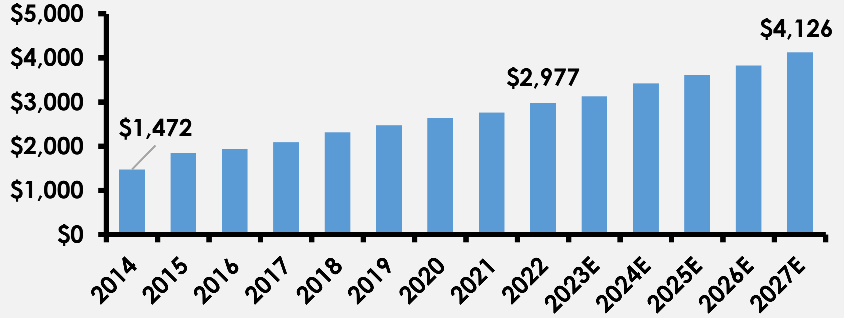
30,100
Miles of Electric and Gas Transmission and Distribution Lines

1,600
Skilled Employees

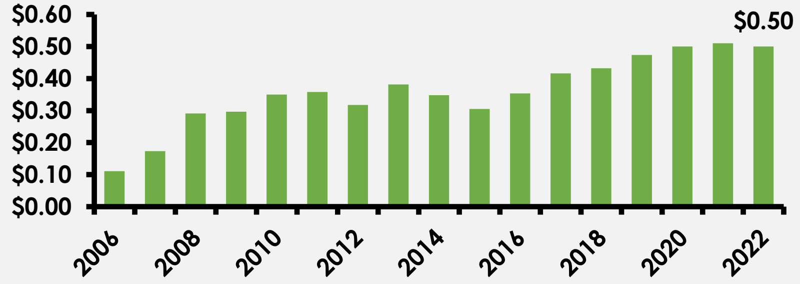


Rate Base[1]

($ in millions)



Segment EPS

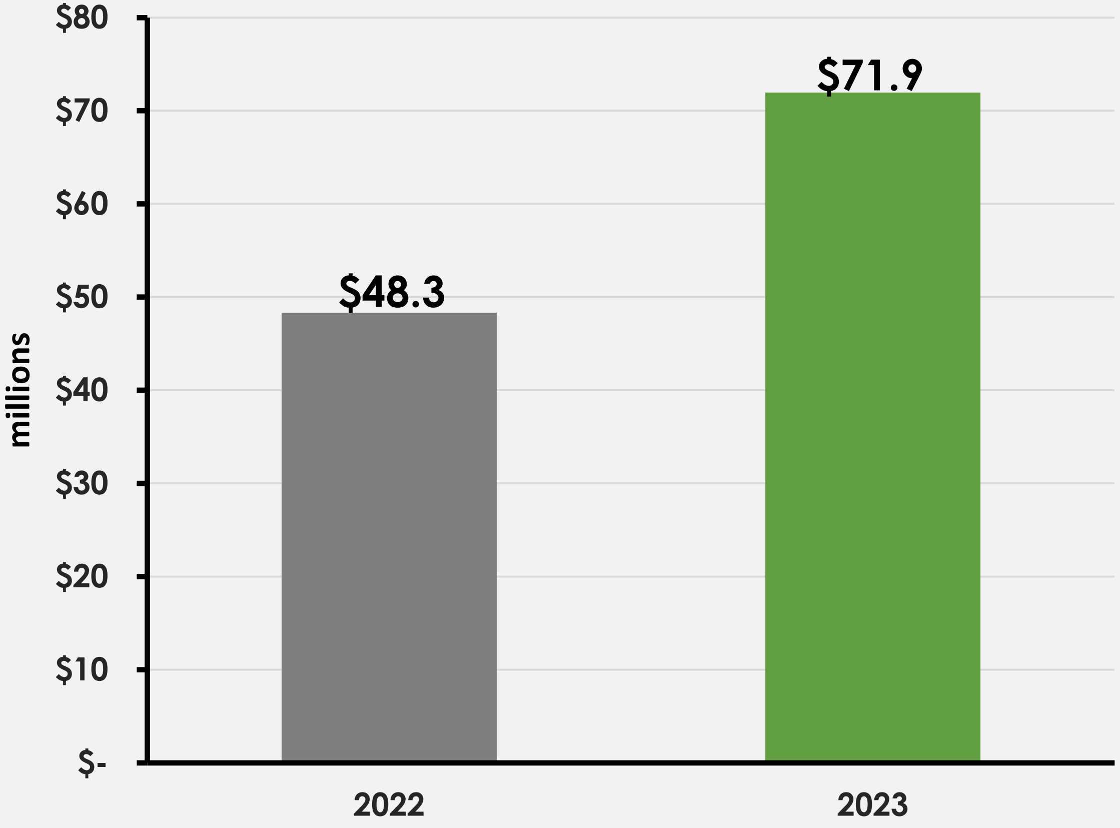


[1] Including CWIP.

ELECTRIC & NATURAL GAS UTILITY
YTD EARNINGS

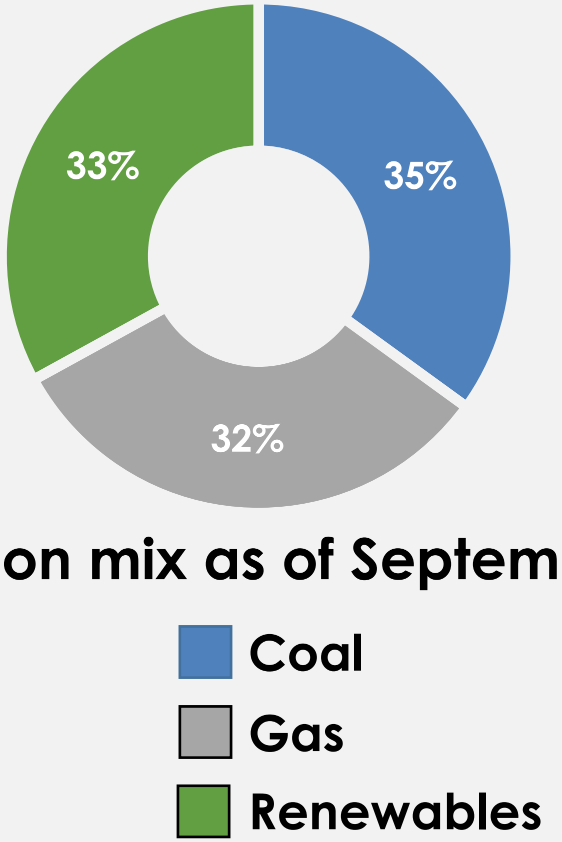
- Earnings of $71.9 million
  - Higher total electric retail sales volumes, largely due to a new large-volume commercial customer
  - Higher rate relief in certain electric and natural gas jurisdictions
  - Higher investment returns on nonqualified benefit plans

GAAP YTD EARNINGS



GENERATION MIX

- Increased renewable generation from 11% of portfolio to 33% since 2010
- Retired three coal-fired units in 2021-2022 totaling 130-megawatts
- Constructing an 88-megawatt gas fired plant as a replacement; expected to be fully operational before year-end
- Coal trending down to 31% over the next year from 69% in 2013 – mix shifting toward renewables and natural gas



Generation mix as of September 30, 2023

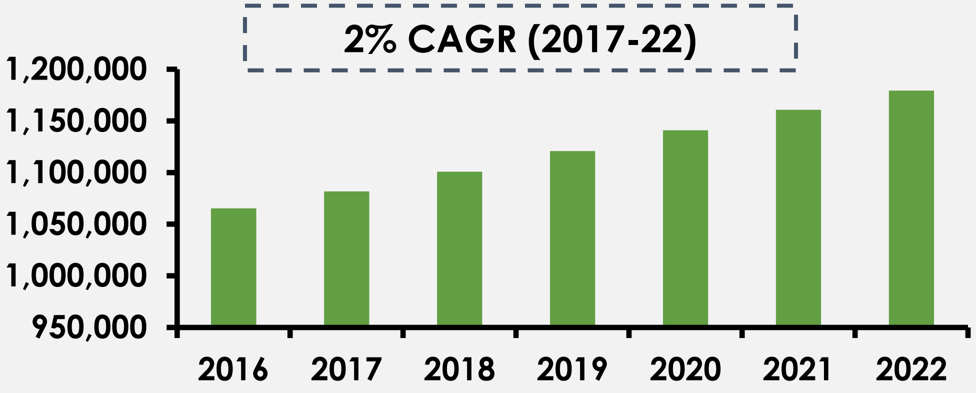
Note: Based on nameplate rating

RATE BASE ORGANIC GROWTH DRIVERS

Continuous Rate Base growth supported by strong customer growth and system investments

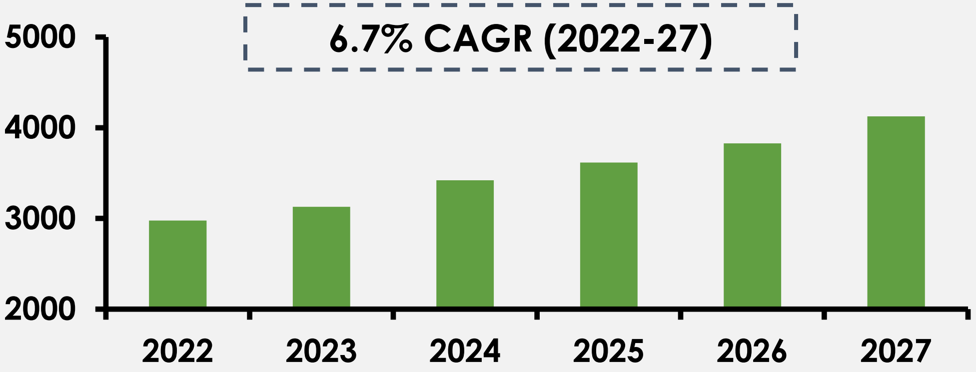
- Utility earnings growth is driven by capital deployment, resulting in growth in Rate Base
- Organic growth is driven in part by positive demographics
  - 2% annual customer growth rate since 2017 and 1-2% continued projected growth
  - Compares favorably to other utilities
- MDU Utilities Group expected to deploy $2.3 billion in capex over the next 5 years
  - Focused on meeting service needs related to customer growth as well as replacing, expanding, and modernizing infrastructure within the electric and natural gas distribution systems

Historical MDU Utilities Group Customer Base



Projected MDU Utilities Group Rate Base[1]

($ in millions)



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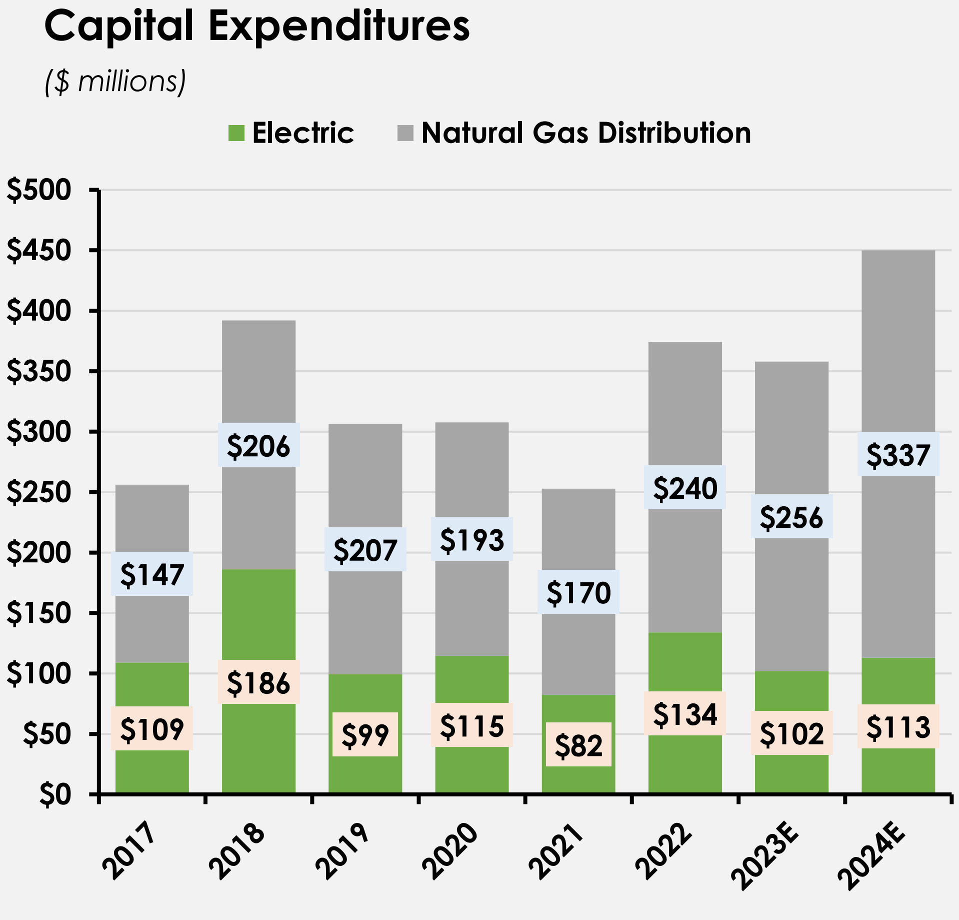
1. Including CWIP.

CAPITAL EXPENDITURES

Balanced CapEx investments support growth

- Investments will be deployed for:
  - – System upgrades and replacements needed to supply safe and reliable service
  - – Supporting customer growth
- Capital expenditures forecast also includes:
  - – Construction of 88-megawatt simple-cycle, natural gas-fired combustion turbine near Mandan, North Dakota

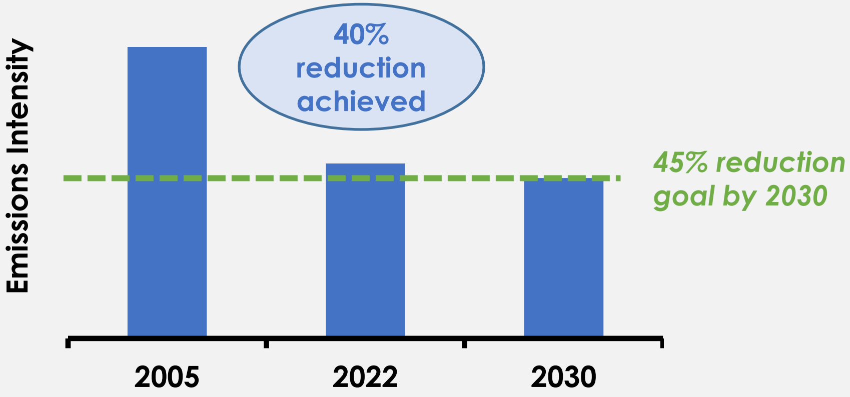


ENVIRONMENTAL FOCUS

Focused on operating our business with a decreasing environmental footprint

GHG Emissions Reduction Targets

- Target to **reduce electric utility GHG emissions by 45% by 2030** vs. 2005 levels
- Reduction to be achieved primarily through the continued diversification of our electric generating fleet, helping drive rate base / earnings growth



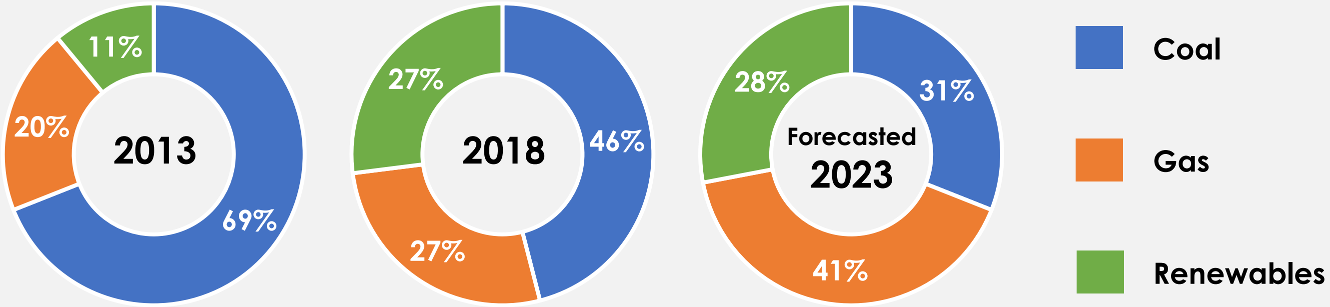
Sustainable Operations

Retirement of Coal Facilities
- Ceased operations at Lewis & Clark Station in Sydney, MT in March 2021
- Ceased operations at Heskett I & II in Mandan, ND in February 2022
- Company no longer wholly owns any coal fired units

Water Use. Facilities safely utilize water from rivers, lakes, and wells for various processes and cleanly discharge them back to the water bodies

Renewable Energy. As of December 31, 2022, approximately 33% of electric generation nameplate capacity was from renewable resources

Transitioning Our Electric Resources (Based on Nameplate Rating)



WBI ENERGY
An MDU Resources Group company

PIPELINE SNAPSHOT

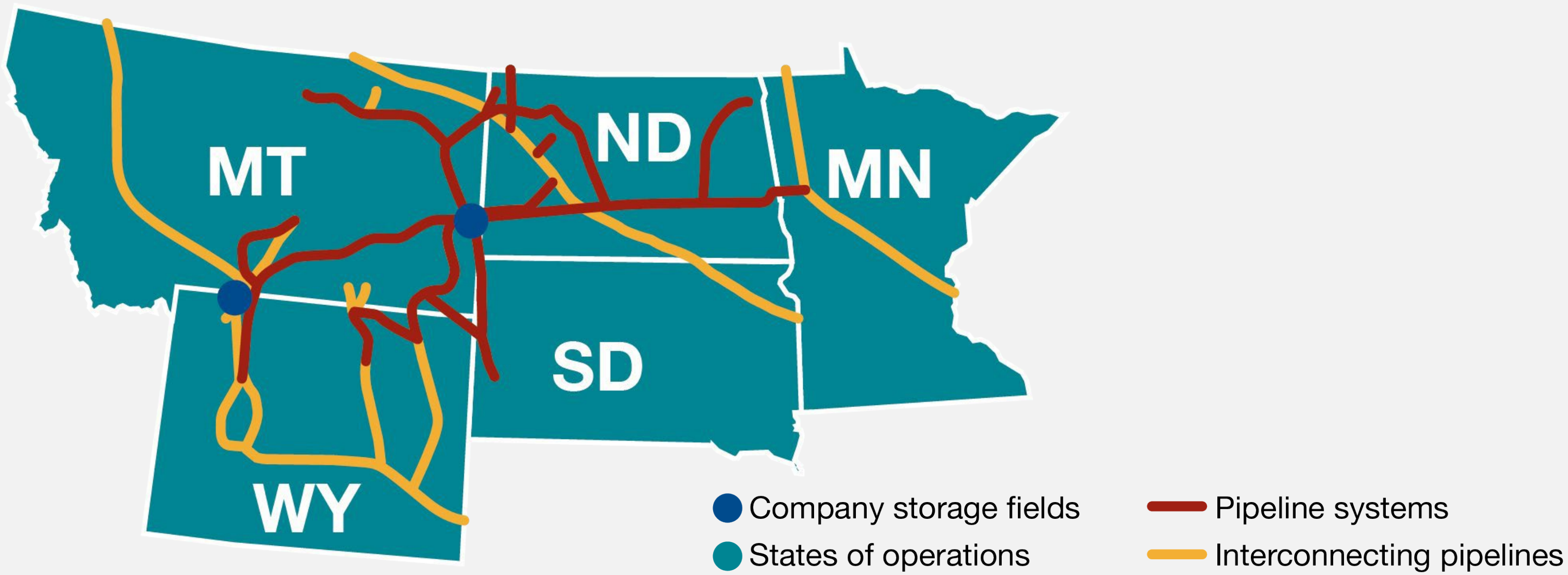
3,800
Miles of Pipe

OVER 2.4 BCF/D
System Capacity

14
Interconnecting Points

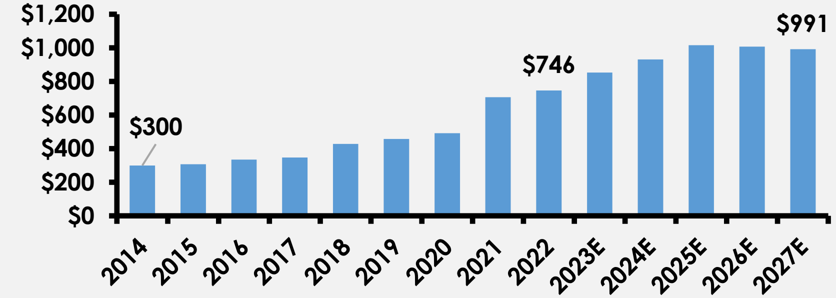
328
Employees

LARGEST
Storage Field in N. America

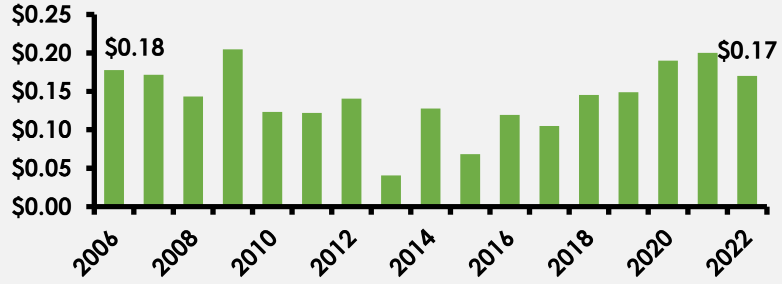


Rate Base[1]

($ in millions)



Segment EPS



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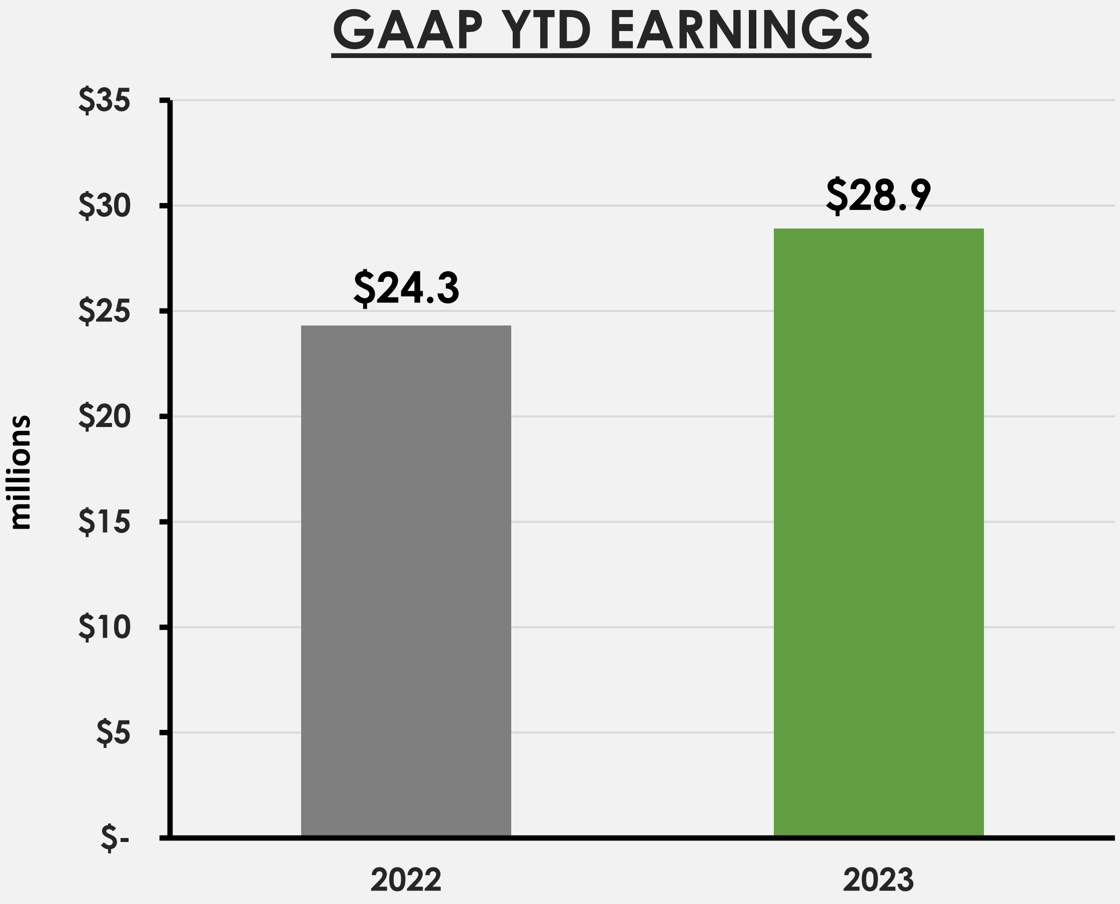
1. Including CWIP.

PIPELINE
YTD EARNINGS

WBI ENERGY
An MDU Resources Group company

- Record earnings of $28.9 million
  - Record transportation volumes, largely due to increased contracted volume commitments from the North Bakken Expansion project
  - Higher transportation and storage related revenue
  - Higher investment returns on nonqualified benefit plans



CAPITAL EXPENDITURES

Balanced CapEx investments support growth

Pipeline Capital Expenditures

($ millions)

2021 CapEx increase largely driven by North Bakken Expansion project construction

2023 CapEx increase largely driven by several organic growth projects, including the Wahpeton Expansion project

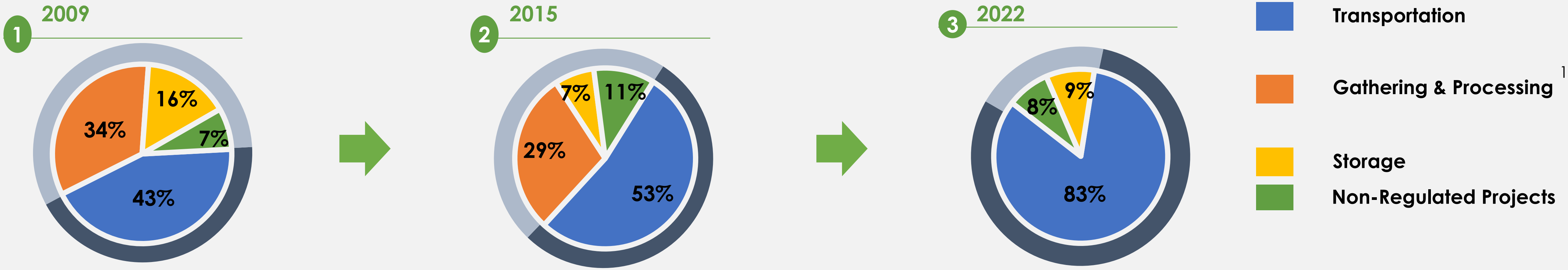
BUSINESS EVOLUTION: INCREASING STABILITY

Fundamentally enhanced business mix since 2008

- Continue to increase regulated transportation mix, providing **low-risk, stable returns**
- Pipeline expansion projects based on long-term customer commitments **increase demand revenue**
- Filed a rate case with the Federal Energy Regulatory Commission on Jan 27, 2023, seeking rate increases for transportation and storage services.

WBI Energy Revenue Mix (2009–2021)

(Percent contribution)



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1. All Gathering & Processing services exited as of December 2020.

PIPELINE EXPANSION & REGULATORY UPDATE

WBI Energy is actively expanding its pipeline system through key projects

- North Bakken Expansion was placed in service in early 2022. Revenues in 2023 are expected to increase by approximately $10 million, largely due to contracted volume commitment increases of approximately 70%, to 215 million cubic feet per day.
- The company began construction in the second quarter on three pipeline projects.
    - Two of these projects were placed in service on Nov. 1, and will add natural gas transportation capacity of 119 million cubic feet per day.
    - The third project is expected to be completed in early 2024, adding natural gas transportation capacity of 175 million cubic feet per day.
- In August 2023, WBI Energy reached a rate case settlement agreement with its customers and FERC staff. On August 24, 2023, the FERC granted a motion to place the agreed-upon settlement rates into effect as of August 1, 2023 on an interim basis, pending final approval of the settlement agreement.

OUR COMMITMENTS
SUSTAINABILITY & COMMUNITY

WBI ENERGY
An MDU Resources Group company

WBI Energy operates sustainably to protect the environment and our communities

WBI ENERGY'S SUSTAINABILITY efforts are closely integrated into our business strategy and help increase efficiency and mitigate risk, all while keeping our communities safe

Environmental investments. Replaced legacy facilities with lower-emitting equipment and installed electric-driven compression where feasible at new facilities, resulting in reductions and savings of potential greenhouse gas emissions of approximately 14,000 and 10,500 metric tons of carbon dioxide equivalent at legacy facilities and new facilities, respectively

Quantifying our impact. Discloses AGA Voluntary Sustainability Metrics, is voluntarily working towards participation in the EPA's Natural Gas STAR Methane Challenge Program, and joined ONE Future Coalition, all while working with peers to develop best practices and adopt cost-saving technologies

Fuel efficiency. Through innovative projects, WBI has already reduced the amount of natural gas consumed by more than 250 million cubic feet per year

Methane. Committed to improving practices to minimize methane emissions by implementing methane control technologies and quantifying emission reductions from these efforts

Employees

- Our focus on safety and training drives the recruitment and retention of top talent
- Strong commitment to a safe work environment providing employees with necessary training and resources
- Regularly surveys employees on a variety of topics to drive internal workforce initiatives

Community

- Safety and reliability are key to maintaining trust with customers and the community, as well as winning repeat business
- Operates a safe natural gas pipeline system through a variety of tools, precautions, and frequent dialogue with our communities
- Pipeline Safety Management System program supports a culture dedicated to public and employee safety and environmental protection

CONSTRUCTION SERVICES SNAPSHOT

MDU CONSTRUCTION SERVICES GROUP

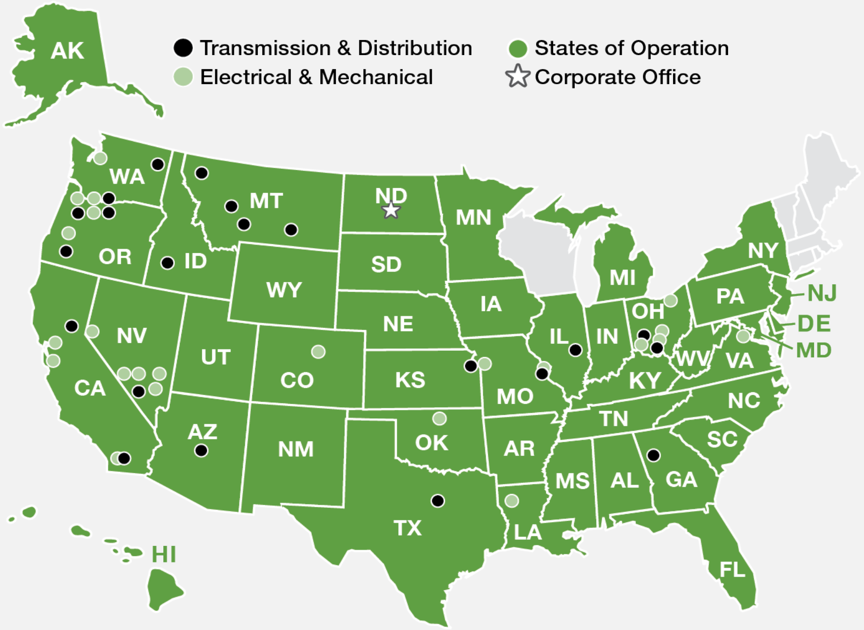
8,000+
Skilled Employees at Peak

43
States of Operation

6
Transmission and Distribution Construction Companies

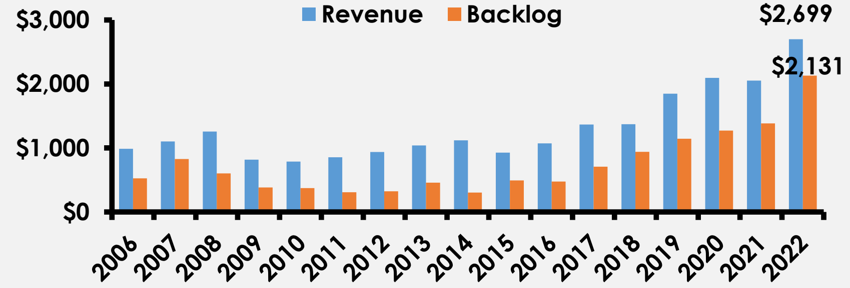
10
Electrical & Mechanical Construction Companies

Ranked 10th
on ENR's Top 600 Specialty Contractors List



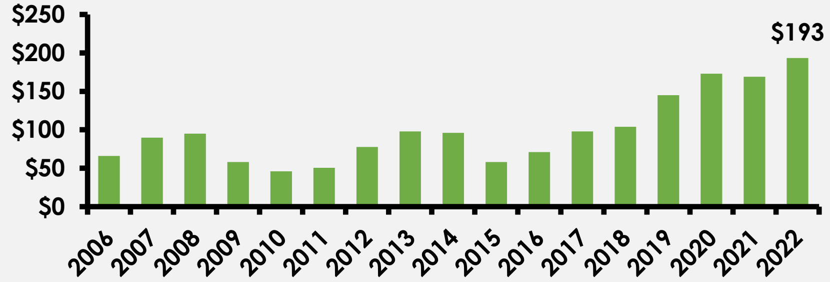
Segment Revenue and Year-End Backlog

($ in millions)



Segment EBITDA[1]

($ in millions)

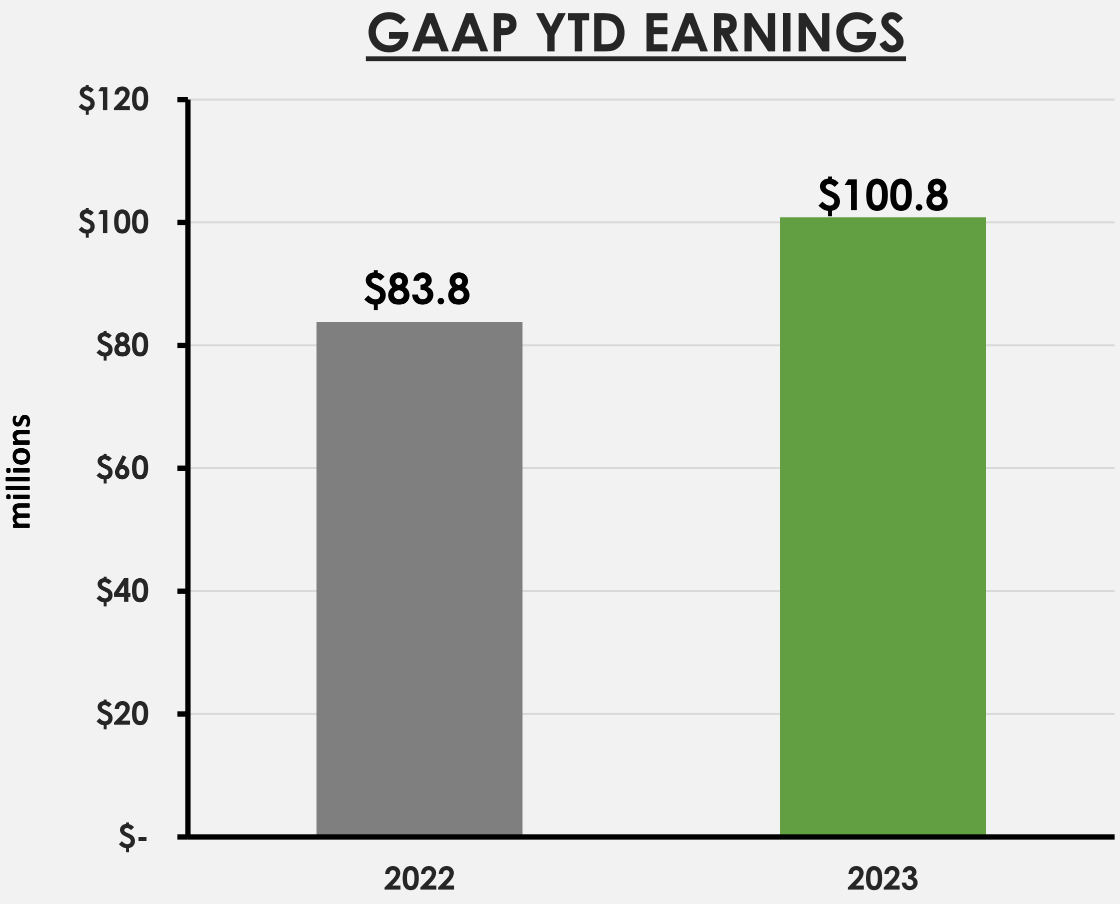


1. Note: EBITDA is considered a non-GAAP financial measure.

CONSTRUCTION SERVICES

YTD EARNINGS

- All-time record earnings of $100.8 million
  - Strong demand for institutional work, particularly heath care and government clients
  - Higher demand for utility-related transmission and distribution work
- All-time record revenue of $2,218.7 million, compared to $1,975.1 million in 2022
- All-time record EBITDA of $164.4 million, compared to $131.2 million in 2022



MARKET LEADER

Leading local presence in Transmission & Distribution and Electrical & Mechanical specialty contracting

- Local brands showcasing national strength across Transmission & Distribution and Electrical & Mechanical contracting
- Trusted brand and reputation; working on high-value projects for the government and the largest U.S. companies across utilities, manufacturing, industrials, transportation, e-commerce and data infrastructure
- Continued growth through organic expansion as well as mergers and acquisitions

High-Value Projects

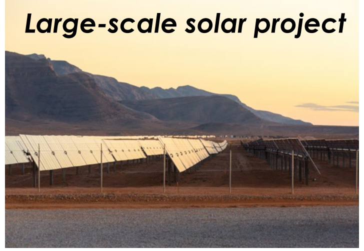


*Image courtesy of McCarthy Holdings, Inc.

Local Brands, National Strength

Bell Electrical Contractors
Bombard Electric, LLC
Bombard Mechanical
Capital Electric
Capital Electric Line Builders, Inc.
Desert Fire Protection
Duro Electric
ESI Electrical Contractors
ILB International Line Builders Inc
Lone Mountain Excavation & Utilities, LLC
Loy Clark Construction Est. 1957
OEG Power On
PerLectric
Rocky Mountain Contractors, Inc.
US Industrial Services, Inc.
Wagner Smith Equipment Co.

QUESTIONS

Appendix

RECONCILIATION OF EBITDA GUIDANCE

($ in millions)

	As of November 2, 2023	
	Construction Services	
	Low	High
Income from continuing operations	$125.0	$140.0
Adjustments:		
Interest expense	20.0	20.0
Income taxes	40.0	45.0
Depreciation, depletion and amortization	25.0	25.0
EBITDA from continuing operations[1]	$210.0	$230.0

1. Note: EBITDA is considered a non-GAAP financial measure.
2. EBITDA calculations do not include "other".

RECONCILIATION OF EBITDA

($ in millions)

	As of September 30, 2023			
	Utility	**Pipeline**	**Construction Services**	**Total**
Income from Continuing Ops.	$71.9	$28.9	$100.8	$201.6
Adjustments:				
Interest Expense	$62.7	$10.0	$11.8	$84.5
Income Taxes	$0.4	$8.1	$34.5	$43.0
Depreciation, Depletion & Amort.	$118.4	$20.0	$17.3	$155.7
EBITDA from continuing ops.[1]	**$253.4**	**$67.0**	**$164.4**	**$484.8**

1. Note: EBITDA is considered a non-GAAP financial measure.
2. EBITDA calculations do not include "other".

RECONCILIATION OF EBITDA

($ in millions)

	For the year ended December 31, 2022				
	Utility	**Pipeline**	**Construction Services**	**Construction Materials**	**Total**
Income from Continuing Ops.	$102.3	$35.3	$124.8	$116.2	$378.6
Adjustments:					
Interest Expense	$70.7	$11.3	$6.3	$30.1	$118.4
Income Taxes	$2.4	$10.2	$40.8	$42.6	$96.0
Depreciation, Depletion & Amort.	$157.2	$26.9	$21.5	$117.8	$323.4
EBITDA from continuing ops.[1]	**$332.6**	**$83.7**	**$193.4**	**$306.7**	**$916.4**

1. Note: EBITDA is considered a non-GAAP financial measure.
2. EBITDA calculations do not include “other”.

ABOUT US

Until the early 1950s, Pacific Northwest communities outside the larger metropolitan areas were passed ov
service. In 1953, Pacific Northwest businessmen Lester Pettit, Spencer Clark, and Stewart Matthews forme
Gas Corporation to serve these communities with clean, affordable natural gas.

In those early days, the founders faced many financial, engineering and operational challenges as they strive
service and enhance their operations. The company grew steadily to become one of the fastest growing natu
the nation.

Today, Cascade serves more than 314,500 customers in 95 communities – 67 of which are in Washington ar
Cascade's service areas are concentrated in western and central Washington and central and eastern Orego

Cascade serves a diverse territory covering more than 32,000 square miles and 700 highway miles from one
to the other. Interstate pipelines transmit Cascade's natural gas from production areas in the Rocky Mounta
Canada.

Customers are served from three operational regions:

Communities Served in Washington

- Aberdeen
- Acme
- Anacortes
- Arlington
- Belfair
- Bellingham
- Blaine
- Bremerton
- Burbank Heights
- Burlington
- Camano Island
- Castle Rock
- Chico
- College Place
- Deming
- East Wenatchee
- Everson
- Elma
- Ferndale
- Finley
- Grandview
- Granger
- Gorst
- Hoquiam
- Kalama
- Kelso
- Kennewick
- Keyport
- La Conner
- Lawrence
- Longview
- Lynden
- Marysville
- Manchester
- McCleary
- Montesano
- Moses Lake
- Mount Vernon
- Moxee
- Nooksack
- Oak Harbor
- Othello
- Pasco
- Paterson/Plymouth

Echo	Nyssa
Gilchrist	Ontario
Hermiston	Pendleton
Huntington	Pilot Rock

English

Equity and the small-stock effect
Annin, Michael
Public Utilities Fortnightly; Oct 15, 1995; 133, 19; ABI/INFORM Global
pg. 42

By Michael Annin

Equity and the Small-Stock Effect

The capital asset pricing model shows risk inherent in return on equity. But something goes wrong when it's used for small-sized companies.

Does the size of a company affect the rate of return it should earn? If smaller companies should earn a higher return than larger firms, then small utilities, because of their size, should be allowed to adjust the rates they charge to customers.

By far the most notable and well-documented apparent anomaly in the stock market is the effect of company size on equity returns. The first study focusing on the impact that company size exerts on security returns was performed by Rolf W. Banz. Banz sorted New York Stock Exchange (NYSE) stocks into quintiles based on their market capitalization (price per share times number of shares outstanding), and calculated total returns for a value-weighted portfolio of the stocks in each quintile. His results indicate that returns for companies from the smallest quintile surpassed all other quintiles, as well as the Standard & Poor's 500 and other large stock indices. A number of other researchers have replicated Banz's work in other countries; nevertheless, a consensus has not yet been formed on why small stocks behave as they do.

One explanation for the higher returns is the lack of information on small companies. Investors must search more diligently for data. For small utilities, investors face additional obstacles, such as a smaller customer base, limited financial resources, and a lack of diversification across customers, energy sources, and geography. These obstacles imply a higher investor return.

The Flaw in CAPM

One of the more common cost of equity models used in practice today is the capital asset pricing model (CAPM). The CAPM describes the expected return on any company's stock as proportional to the amount of systematic risk an investor assumes. The traditional CAPM formula can be stated as:

$$R_s = [\beta_s \times RP] + R_f$$

where:

R_s = expected return or cost of equity on the stock of company "s"
β = the *beta* of the stock of company "s"
RP = the expected equity risk premium
R_f = expected return on a riskless asset.

Table 1: The Size Premium in CAPM
(By Decile Portfolio in NYSE, 1926-94)

Decile	*Beta*	Arithmetic Mean Return	Actual Return in Excess of Riskless Rate**	CAPM Return in Excess of Riskless Rate**	Size Premium (Return in Excess CAPM)
1	0.90	11.01%	5.88%	6.33%	–0.44%
2	1.04	13.09	7.97	7.34	0.63
3	1.09	13.83	8.71	7.70	1.01
4	1.13	14.44	9.32	7.98	1.33
5	1.17	15.50	10.38	8.22	2.16
6	1.19	15.45	10.33	8.38	1.95
7	1.24	15.92	10.79	8.75	2.05
8	1.29	16.84	11.72	9.05	2.67
9	1.36	17.83	12.71	9.57	3.14
10	1.47	21.98	16.86	10.33	6.53

**Betas* are estimated from monthly returns in excess of the 20-year government bond income return, January 1926-December 1994.
**Historical riskless rate measured by the 69-year arithmetic mean income return component of 20-year government bonds.
Source: SBBI 1995 Yearbook

Table 2: CAPM vs. CAPM w/ Size Premium

(By Percentile for Electric, Gas, and Sanitary Services Utilities)

	CAPM	CAPM with Size Premium
90th Percentile	16.42%	18.92%
75th Percentile	12.56%	14.72%
Median	10.89%	12.58%
25th Percentile	9.86%	11.39%
10th Percentile	8.63%	10.65%

(Weighted by Market Capitalization)

	CAPM	CAPM with Size Premium
Industry Composite	11.76%	12.33%
Large Company Composite	12.05%	12.07%
Small Company Composite	13.93%	17.95%

Source: Cost of Capital Quarterly '95 Yearbook by Ibbotson Associates
Note: Public utilities include electric, gas, and sanitary services companies.

Table 1 shows *beta* and risk premiums over the past 69 years for each decile of the NYSE. It shows that a hypothetical risk premium calculated under the CAPM fails to match the actual risk premium, shown by actual market returns. The shortfall in the CAPM return rises as company size decreases, suggesting a need to revise the CAPM.

The risk premium component in the actual returns (realized equity risk premium) is the return that compensates investors for taking on risk equal to the risk of the market as a whole (estimated by the 69-year arithmetic mean return on large company stocks, 12.2 percent, less the historical riskless rate). The risk premium in the CAPM returns is *beta* multiplied by the realized equity risk premium.

The smaller deciles show returns not fully explainable by the CAPM. The difference in risk premiums (realized versus CAPM) grows larger as one moves from the largest companies in decile 1 to the smallest in decile 10. The difference is especially pronounced for deciles 9 and 10, which contain the smallest companies.

Based on this analysis, we modify the CAPM formula to include a small-stock premium. The modified CAPM formula can be stated as follows:

$$R_s = [\beta_s \times RP] + R_f + SP$$

where:

SP = small-stock premium.

Because the small-stock premium can be identified by company size, the appropriate premium to add for any particular company will depend on its equity capitalization. For instance, a utility with a market capitalization of $1 billion would require a small capitalization adjustment of approximately 1.3 percent over the traditional CAPM; at $400 million, approximately 2.1 percent, and at only $100 million, approximately 4 percent.

Again, these additions to the traditional CAPM represent an adjustment over and above any increase already provided to these smaller companies by having higher *betas*.

Implications for Smaller Utilities

These findings carry important ramifications for relatively small public utilities. Boosting the traditional CAPM return by a full 400 basis points for small utilities translates into a substantial premium over larger utilities.

Table 2 shows the results of an analysis of 202 utility companies that calculated cost of equity figures. Composites (arithmetic means) weighted by equity capitalization were also calculated for the largest and smallest 20 companies. The results show the impact size has on cost of equity.

For the traditional CAPM, the large-company composite shows a cost of equity of 12.05 percent; the small company composite, 13.93 percent. However, once the respective small capitalization premium is added in, the spread increases dramatically, to 12.07 and 17.95 percent, respectively. Clearly, the smaller the utility (in terms of equity capitalization), the larger the impact that size exerts on the expected return of that security. ▼

Michael Annin, CFA, is a senior consultant with Ibbotson Associates, specializing in business valuation and cost of capital analysis. He oversees the Cost of Capital Quarterly, *a reference work on using cost of capital for company valuations.*

United States Court of Appeals
FOR THE DISTRICT OF COLUMBIA CIRCUIT

Argued November 18, 2021 Decided August 9, 2022

No. 16-1325

MISO TRANSMISSION OWNERS, ET AL.,
PETITIONERS

v.

FEDERAL ENERGY REGULATORY COMMISSION,
RESPONDENT

MIDCONTINENT INDEPENDENT SYSTEM OPERATOR, INC., ET AL.,
INTERVENORS

Consolidated with 16-1326, 20-1182, 20-1240, 20-1241,
20-1248, 20-1251, 20-1267, 20-1513

On Petitions for Review of Orders of the
Federal Energy Regulatory Commission

Christopher R. Jones and *Matthew J. Binette* argued the causes for petitioner MISO Transmission Owners, et al. With them on the joint briefs were *Miles H. Kiger, Wendy N. Reed, Michael J. Thompson, Victoria M. Lauterbach, Ryan J. Collins,* *Steven J. Ross*, and *Stacey L. Burbure*. *David S. Berman* entered an appearance.

David E. Pomper argued the cause for petitioners on Return Issues. With him on the briefs were *Robert A. Weishaar, Jr.*, *Omar Bustami*, *Vasiliki Karandrikas*, *Gerit F. Hull*, *Matthew R. Rudolphi*, *Michael Postar*, *Bhaveeta K. Mody*, *Sean T. Beeny*, *Barry Cohen*, *Andrea I. Sarmentero Garzon*, *John Michael Adragna*, *James H. Holt*, *David Eugene Crawford*, and *Benjamin Sloan*.

Eric B. Wolff argued the cause for petitioners on Refund Issues. With him on the briefs were *Jane E. Rueger*, *Robert A. Weishaar, Jr.*, *Alison R. Caditz*, *Vasiliki Karandrikas*, *Omar Bustami*, *Matthew R. Rudolphi*, *David E. Pomper*, *Gerit F. Hull*, *Sean T. Beeny*, *Barry Cohen*, *Andrea I. Sarmentero Garzon*, *Michael Postar*, *Bhaveeta K. Mody*, *James H. Holt*, *David Eugene Crawford*, *John Michael Adragna*, and *Benjamin Sloan*. *James K. Mitchell* entered an appearance.

Jason T. Gray, *Michael R. Fontham*, *Dana M. Shelton*, and *Justin A. Swaim* were on the briefs for intervenors supporting Consumer-Side petitioners. *Arthur W. Iler* entered an appearance.

Catherine P. McCarthy, *Blake R. Urban*, *Nicholas J. Cicale*, *Gary Epler*, *Phyllis E. Lemell*, *Lisa B. Luftig*, *Mary E. Grover*, *Sean A. Atkins*, *David M. Gossett*, *S. Mark Sciarrotta*, *Jeffrey M. Jakubiak*, and *Jennifer C. Mansh* were on the brief for *amici curiae* in support of Transmission Owning petitioners.

Lona T. Perry, Deputy Solicitor, Federal Energy Regulatory Commission, argued the cause for respondent.

With her on the brief were *Matthew R. Christiansen*, General Counsel, and *Robert H. Solomon*, Solicitor.

Michael R. Fontham argued the cause for intervenors in support of respondent aligned with remaining petitioners. With him on the brief were *Andrea I. Sarmentero Garzon, Matthew R. Rudolphi, Sean T. Beeny, Barry Cohen, Benjamin Sloan, Joshua E. Adrian, Gerit F. Hull, James H. Holt, David Eugene Crawford, Robert A. Weishaar, Jr., David E. Pomper, Vasiliki Karandrikas, Omar Bustami, Michael Postar, Bhaveeta K. Mody, Dana M. Shelton, Justin A. Swaim, Deborah A. Moss, Jason T. Gray*, and *Emerson J. Hilton. Arthur W. Iler* entered an appearance.

Matthew J. Binette argued the cause for intervenors in support of respondent. With him on the joint brief were *Steven J. Ross, Stacey L. Burbure, Wendy N. Reed, Michael J. Thompson, Victoria M. Lauterbach, Ryan J. Collins, Christopher R. Jones*, and *Miles H. Kiger. David S. Berman* entered an appearance.

Before: SRINIVASAN, *Chief Judge*, KATSAS and WALKER, *Circuit Judges*.

Opinion for the Court filed by *Circuit Judge* WALKER.

WALKER, *Circuit Judge*: The Federal Energy Regulatory Commission is responsible for ensuring that interstate electricity rates are "just and reasonable." 16 U.S.C. §§ 824d(a), 824e(a). To do so, it approves electricity providers' proposed rate changes, and it can require them to change their rates if the rates become unreasonable. This case is about one of FERC's rate determinations.

Midcontinent Independent System Operator, Inc. administers the electric grid on behalf of the companies that own transmission lines. Those transmission owners invested money to build their transmission lines, and MISO must charge customers electricity-transmission rates that provide those companies an appropriate return on their investment. That return-on-equity component of the transmission rates, which we'll just call the Return, is at issue in this case.

In this case, a group of customers thought MISO provided transmission owners a too-generous Return. They asked FERC to reduce that aspect of MISO's rates. FERC did. In the process, it completely overhauled its approach to setting an appropriate Return.

Both the customers and transmission owners now challenge several aspects of the FERC proceedings as unlawful or arbitrary and capricious.

We agree with the customers that FERC's development of the new Return methodology was arbitrary and capricious, so we vacate its rate-determination orders and remand for further proceedings. Because the other challenged aspects of FERC's orders flow from FERC's rate determination, we do not reach them.

I

We start this section with some background on the general regulatory framework for electricity-transmission rates. Then we describe the history of FERC's approach to Return determinations. Finally, we explain what happened in these proceedings.

A

For most of the twentieth century, vertically integrated state and local utilities monopolized electricity markets. *See Atlantic City Electric Co. v. FERC*, 295 F.3d 1, 4 (D.C. Cir. 2002). When technological progress enabled competitors to offer lower prices for electricity, the incumbent utilities used their control of transmission lines to keep competitors out of the market. *Id.* That exclusion caused higher prices. So in 1996, FERC required utilities to provide open access to transmission lines. *Id.* To help achieve its open-access goals, FERC created a framework for independent companies, called independent system operators, that would impartially operate transmission lines. *Id.* at 5.

MISO performs that service for fifteen states in the middle of the country from Louisiana up to Minnesota (and beyond to Manitoba). In exchange for its services, it charges transmission rates that approximate the costs it incurs plus an appropriate return on equity for the transmission owners' original investment in building the lines. *See* FERC, Energy Primer: A Handbook of Energy Market Basics 59-60 (2020).

Like all public utilities, MISO must file its proposed rates with FERC for approval. As part of its review, FERC ensures that the Return portion of the rates is appropriate to compensate transmission owners for the risks they took and to attract future investment in transmission lines. *Emera Maine v. FERC*, 854 F.3d 9, 20 (D.C. Cir. 2017).

There are two ways that MISO's rates can change.

One, called a Section 205 proceeding, is utility-initiated. If MISO wishes to change its rates, it can file a new set of proposed rates with FERC. 16 U.S.C. § 824d(d). FERC then reviews the proposed rates to determine whether they are just and reasonable. *Id.* § 824d(e). If they are, MISO can charge them. *NRG Power Marketing, LLC v. FERC*, 862 F.3d 108, 114 (D.C. Cir. 2017). If not, FERC rejects them. *Id.*

The other, called a Section 206 proceeding, is customer- or FERC-initiated. A customer can file a complaint alleging that a current rate is unjust and unreasonable, or FERC can set a hearing on its own motion. 16 U.S.C. § 824e(a). At step one, FERC decides if the old rate is unjust and unreasonable. *Id.* If so, then FERC proceeds to step two and sets a new rate. *Id.*

Until FERC sets a new rate in a Section 206 proceeding, customers continue to pay the challenged rates. *See City of Anaheim v. FERC*, 558 F.3d 521, 525 (D.C. Cir. 2009). So Congress gave FERC limited refund authority. At the beginning of the proceeding, FERC sets "a refund effective date." 16 U.S.C. § 824e(b). It can then give refunds of any excess payments for fifteen months after that refund effective date. *Id.* Those excess payments are calculated as the difference between the old, challenged rate and the new rate ordered by FERC. *Id.*

This case is about a Section 206 proceeding.

B

To understand what FERC did in this proceeding, it helps to have some historical background on FERC's methodology for assessing the reasonableness of the existing Return and, if necessary, setting a new one.

Since the 1980s, FERC calculated the Return with the aid of a financial tool called the discounted-cash-flow model. That model uses a company's stock price to represent the company's value to investors. *Canadian Association of Petroleum Producers v. FERC*, 254 F.3d 289, 293 (D.C. Cir. 2001). It assumes that the stock price is equal to all the dividends the company will pay out in the future "discounted at a market rate commensurate with the stock's risk." *Id.* A simplified version of that baseline formula is $P = D/(r\text{-}g)$, "where P is the price of the stock at the relevant time, D is the dividend to be paid at the end of the first year, r is the rate of return and g is the expected growth rate of the firm." *Id.* That is the version investors use to try to calculate a company's stock price. But to calculate an appropriate Return for transmission owners, FERC rearranges the equation to be:

$$r = D/P + g.$$[1]

For publicly traded companies, calculating an appropriate Return with the discounted-cash-flow model is relatively easy because of its publicly traded stock price. But for privately held companies like the transmission owners, which have no public stock price, FERC uses a proxy group of comparable, publicly traded companies. *Id.* at 293-94. With that proxy group of public companies, FERC can approximate what a discounted-cash-flow analysis should look like for the privately held companies at issue. *Id.*

When FERC chooses a proxy group and conducts a discounted-cash-flow analysis for each company in the group, it gets a range of possible Returns that FERC calls the "zone of reasonableness." *Emera Maine v. FERC*, 854 F.3d 9, 15 (D.C.

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[1] As we said, $r = D/P + g$ is a simplified version of FERC's formula. The actual, more complicated formula includes a dividend multiplier, which accounts "for the fact that dividends are paid on a quarterly basis." JA 514. It is $r = D/P(1 + .5g) + g$. But because the dividend multiplier affects none of the analysis in this case, we'll use the simplified formula when discussing the discounted-cash-flow model.

Cir. 2017). A Return must be a single value, so FERC then needs to choose a point within the zone. It typically uses the midpoint, at least for independent system operators like MISO. *See Southern California Edison Co. v. FERC*, 717 F.3d 177, 186 (D.C. Cir. 2013).

That was the state of play until 2014: FERC would produce a zone of reasonableness using a discounted-cash-flow analysis of proxy group companies, then set the Return at the midpoint.

Then FERC changed things up. In a rate-review proceeding for New England's independent system operator, FERC found that anomalous market conditions required a higher Return than the one provided by the midpoint of the discounted-cash-flow model's zone of reasonableness. *Emera Maine*, 854 F.3d at 18. It looked at several other models to determine how much higher the Return should go and ultimately set the Return at the midpoint of the upper half of the zone of reasonableness. *Id.*

That brings us to this case.

C

This case started with two separate Section 206 complaints against MISO's rates.

In 2013, a group of customers believed the Return component of MISO's existing rate was too high. They filed a Section 206 complaint asking FERC to lower it. That was this case's first complaint.

FERC set a refund effective date of November 12, 2013, which meant that customers could only get refunds for overpayments through February 11, 2015. But FERC did not resolve the first complaint by February 11, 2015. The following day, a different group of customers filed a complaint challenging the same MISO rate. That was this case's second complaint.

Finally, on September 28, 2016, FERC resolved the first complaint in Opinion No. 551. It agreed with the customers and reduced the Return from 12.38% to 10.32%. In doing so, it used the same Return-setting methodology that it had developed in the New England proceeding.

The next year, in *Emera Maine v. FERC*, we vacated FERC's orders from the New England proceeding. 854 F.3d at 30. We identified two infirmities in FERC's analysis. First, as the transmission owners had argued, FERC "never actually explained how" the New England transmission owners' existing Return "was unjust and unreasonable." *Id.* at 26. And second, as the customers had argued, FERC failed to justify its decision to set the Return at the three-quarters point of the zone of reasonableness. *Id.* at 28-29.

Because FERC had relied so heavily in this proceeding on the orders that we vacated in *Emera Maine*, FERC chose to revisit Opinion 551. It set the first complaint for rehearing and informed the parties that it planned to resolve the second complaint in the same rehearing proceeding.

In its rehearing order, FERC proposed an entirely new methodology for calculating a just and reasonable Return. The proposal used four different financial models, giving each equal weight:

- Model 1, discounted cash flow (as described three pages ago);

- Model 2, capital-asset pricing;[2]
- Model 3, expected earnings;[3] and
- Model 4, risk premium.[4]

FERC planned to use the first three models, each of which produce a zone of reasonableness, to answer the threshold question whether an existing rate is unjust and unreasonable. Because risk premium (Model 4) produces only a single point, FERC intended to leave it out of that first step. It planned to create a composite zone produced by the average of the first three models' zones of reasonableness, then divide the composite zone to create presumptively just and reasonable ranges for utilities based on their risk profiles, as this image shows:

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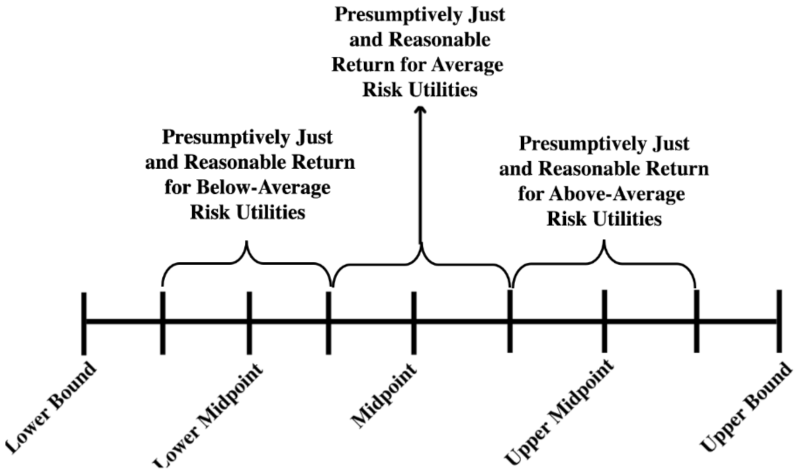
[2] The Return for this model depends on, among other things, a risk-free rate like the Treasury-bond rate, an analysis of the returns in the market, and an estimate of the company's riskiness. Part III.B of this opinion explains it in more detail.

[3] This model produces a Return based on the earnings investors in comparable stocks expect to receive based on those stocks' "book value," which measures the difference between a company's assets and liabilities. Spoiler alert: FERC will later drop this model from its methodology.

[4] This model subtracts past corporate-utility-bond rates from past Returns to calculate an average risk premium that FERC has given in the past. The new Return is that number added to the current Treasury-bond rate. We will explain more about this model in Part III.E.



Then, if FERC found an existing Return unjust and unreasonable, it would set a new Return by averaging the midpoint (or the one-quarter or three-quarters point for utilities of below-average and above-average risk respectively) of the first three models with the single point that the risk-premium model (Model 4) produces.

A year later, when FERC issued its second order in this proceeding — Opinion No. 569 — it abandoned expected earnings (Model 3) and risk premium (Model 4), and made other, more minor tweaks to its proposed Return methodology. It then applied the new methodology, again found the pre-complaint 12.38% Return unjust and unreasonable, and set a new Return of 9.88%. FERC backdated that new Return to make it effective as of September 28, 2016, requiring the transmission owners to refund — for the period between the first and second orders — the difference between the 10.32%

FERC had set in its first order and the 9.88% it had set in its second order.[5]

As it had promised, FERC also resolved the second complaint in Opinion 569. It determined that the currently effective Return was the new 9.88% Return that it had just imposed. Then it found that 9.88% was not unjust and unreasonable. It therefore did not order a new rate in response to the second complaint. And because it had not ordered a new rate, FERC concluded that it could not order a refund for the second complaint's fifteen-month refund period.

The customers and transmission owners alike found fault with Opinion 569, so both petitioned for rehearing on several grounds. FERC granted rehearing and, in its third order — Opinion 569-A — FERC again changed its Return methodology. It added risk-premium (Model 4) back into the mix and shifted the presumptively just and reasonable zones, among other things.

After explaining its changes, FERC applied the new Return methodology to, yet again, find the pre-complaint 12.38% Return unjust and unreasonable. FERC then set a new Return of 10.02%, which it again backdated to September 28, 2016. Finally, it used that 10.02% Return to again reject the second complaint.

The parties again sought rehearing before FERC. In response, FERC issued Opinion No. 569-B, which tweaked the Return methodology a bit without making any further major changes.

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[5] The MISO transmission owners' primary challenge focuses on the lawfulness of this backdating decision. Because we do not reach that question, we won't delve into the sides' conflicting positions.

This chart summarizes the relevant FERC proceedings.

<table>
<tr><td colspan="2">First Section 206 Complaint: **November 12, 2013**
(Refund period = November 12, 2013 – February 11, 2015)</td></tr>
<tr><td colspan="2">Second Section 206 Complaint: **February 12, 2015**
(Refund period = February 12, 2015 – May 11, 2016)</td></tr>
<tr><td>**September 28, 2016**
FERC Opinion No. 551
Only addresses first complaint</td><td>New Return = 10.32%
Orders refunds for November 12, 2013 – February 11, 2015
Return methodology: applies methodology from the New England ISO proceeding</td></tr>
<tr><td colspan="2">**April 14, 2017**: This Court issues *Emera Maine*, vacating the opinion on which Opinion 551 was based.</td></tr>
<tr><td>**November 21, 2019**
FERC Opinion No. 569
Addresses both complaints</td><td>New Return = 9.88%
Orders refunds for November 12, 2013 – February 11, 2015 and backdates the new rate's effective date to September 28, 2016, when it issued Opinion 551.
Dismisses second complaint.</td></tr>
</table>

	Return methodology: rejects the expected-earnings and risk-premium models; will use only the discounted-cash-flow and capital-asset models.
May 21, 2020 FERC Opinion No. 569-A Addresses both complaints	New Return = 10.02% Requires refunds for the same periods as Opinion 569. Still dismisses second complaint. Return methodology: will now use the risk-premium model in the Return analysis in addition to the discounted-cash-flow and capital-asset models.
November 19, 2020 FERC Opinion No. 569-B Addresses both complaints	Return still = 10.02% Requires refunds for the same periods as Opinion 569-A Still dismisses second complaint. Return methodology: corrected certain inputs to the risk-premium model but continued to reach the same result it reached in Opinion No. 569-A

II

Under the Administrative Procedure Act's arbitrary-and-capricious standard, our review of FERC's ratemaking choices is limited. 5 U.S.C. § 706(2)(A); *see also Emera Maine v. FERC*, 854 F.3d 9, 21-22 (D.C. Cir. 2017). We must deny the petitions for review as long as FERC "has made a principled and reasoned decision supported by the evidentiary record." *Id.* at 22 (quoting *Southern California Edison Co. v. FERC*, 717 F.3d 177, 181 (D.C. Cir. 2013)). That inquiry includes verifying that FERC had a reasoned basis for any changes of heart. *Verso Corp. v. FERC*, 898 F.3d 1, 7 (D.C. Cir. 2018).

III

The customers challenge FERC's new Return methodology on five grounds. First, they argue that FERC should not have altered its previous approach to balancing long-term and short-term growth rates in the discounted-cash-flow model (Model 1). Second, they challenge three aspects of FERC's approach to the capital-asset model (Model 2). Third, they argue that FERC's creation of presumptively just and reasonable ranges at step one of the Section 206 analysis was arbitrary and capricious. Fourth, they argue that FERC should have set the new Return based on the median of the zone of reasonableness rather than the midpoint. And fifth, they challenge FERC's decision to resuscitate the risk-premium model (Model 4) in its second rehearing order shortly after interring the model in its first rehearing order.

We find the first four of those arguments unpersuasive. But we agree with the customers' final argument. And that conclusion is alone enough to make FERC's rate orders arbitrary and capricious.

A

The customers take aim at a change that FERC made to its discounted-cash-flow analysis (Model 1). Remember, the simplified version of that is $r = D/P + g$, with the letters representing the **R**eturn, **d**ividend, stock **p**rice, and expected **g**rowth rate.

In conducting a discounted-cash-flow analysis for a company, FERC balances short-term and long-term expected growth to pick an expected growth rate. Before 1999, FERC used a fifty-fifty split. *Canadian Association of Petroleum Producers v. FERC*, 254 F.3d 289, 292, 297 (D.C. Cir. 2001). After 1999, FERC used a two-thirds-short-term versus one-third-long-term split. *Id.* at 297.

In this proceeding, FERC changed to a four-fifths-short-term versus one-fifth-long-term split. When we approved the 1999 change (from the pre-1999 fifty-fifty split), we noted that because this kind of weighting doesn't lend itself to "strict rules, it would likely be difficult to show that [FERC] abused its discretion in the weighting choice." *Id.*

That remains true. Short-term rates are more reliable projections; long-term rates just "normalize any distortions" in the short-term rates. *Id.* (cleaned up). Recently, the normalizing value of long-term rates has declined as the short-term and long-term projections have converged. So as the importance of long-term rates has declined, FERC decided that their role in the discounted-cash-flow analysis should too. That was not arbitrary and capricious.

B

The customers next challenge three aspects of FERC's application of the capital-asset model (Model 2). We reject each challenge.

That model begins with the following formula:

Return = risk-free rate + beta(expected return – risk-free rate).

Let's break down each term in that formula, as FERC applied it in this proceeding:

- The risk-free rate is the Treasury-bond rate.
- The "beta" is a company-specific value that industry experts assign to measure a company's riskiness as an investment. A beta value of one represents average risk, such that a beta below one represents a lower-risk company and a beta above one represents a higher-risk company.[6]

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[6] Specifically, the beta looks at risk as compared to the full market. So an investment that "fluctuates exactly in step with the market," which means that the investment's "rate of return increases on average by 1 percent when the market's return increases 1 percent," will have a beta of one. A. Lawrence Kolbe, James Read, Jr. & George Hall, *The Cost of Capital: Estimating the Rate of Return for Public Utilities* 70 (1984).

- The expected return is the result of a discounted-cash-flow analysis of all dividend-paying companies in the S&P 500.[7]

Although FERC's application of the model begins with that formula, it doesn't end with it. Before running the formula, FERC adjusts the beta towards 1.0 because some finance scholars believe that betas "converge to 1.0" in the long run. JA 611 (quotation marks omitted). Then, after running the formula, FERC takes the formula's Return result and applies a "size-premium adjustment" to that result. The adjustment is a value meant to ensure that the model adequately accounts for companies' sizes.

For this model, the customers challenge: (1) FERC's decision not to include long-term growth rates in its analysis of

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[7] For some concrete examples of that formula in action, imagine three companies with slightly different risk profiles at a time when (1) the risk-free rate is 3% and (2) the discounted-cash-flow analysis of dividend-paying companies in the S&P 500 produces an expected return of 10%. Let's calculate the three companies' Returns using the formula above:

- If Company A has a completely average risk profile, its Beta is 1. So Company A has a Return of 10%. That's because 10 = 3 + 1(10 - 3).

- Say Company B is slightly riskier than Company A. If its Beta is 1.05, then its Return is 10.35%. That's because 10.35 = 3 + 1.05(10 - 3).

- Finally, say Company C is slightly safer than Company A. If its Beta is 0.95, then its Return is 9.65%. That's because 9.65 = 3 + 0.95(10 - 3).

the S&P 500; (2) its use of *adjusted* betas (as part of the formula) with a size-premium adjustment derived from *unadjusted* betas (applied after running the formula); and (3) its use of betas based on the market risk of the New York Stock Exchange with an expected market return based on the S&P 500. We will address each individually.

1

For the dividend-paying S&P 500 companies that FERC used to determine the "expected return," no one knows for sure how much they will grow. But those companies' growth rates are necessary to calculate the expected return. So FERC filled in that blank with five-year growth projections from the Institutional Brokers' Estimate System. It rejected the customers' request that it average those five-year projections with longer-term growth projections.

FERC adequately explained that decision. It cited financial research that supported the use of only short-term growth rates. And it explained that the short-term rates better reflect an investor's expected return on an investment in the S&P 500 as an index. That's because the S&P 500 is regularly updated to include only companies with high market capitalization. Further, FERC explained that the S&P 500 includes companies at all stages of growth, so older companies with lower growth potential will balance out younger companies with higher growth potential. In light of the "great deference" that we afford FERC's ratemaking analysis, that explanation is sufficient. *See FERC v. Electric Power Supply Association*, 577 U.S. 260, 292 (2016) (cleaned up).

The second issue concerns the size-premium adjustment that FERC applied to the result of its formula. Ibbotson, the company that calculated the size premium, analyzed a large group of companies in the New York Stock Exchange. To grossly simplify, Ibbotson applied a capital-asset formula to those companies and then saw if there were any differences in the results that were best explained by size. *See* Frank Torchio & Sunita Surana, *Effect of Liquidity on Size Premium and Its Implications for Financial Valuations*, 9 J. Bus. Valuation & Econ. Loss Analysis 55, 56-57 (2014).

Ibbotson used *unadjusted* betas in its capital-asset formula. But recall that FERC used *adjusted* betas for its capital-asset formula. The customers argue that FERC's decision to use both despite that mismatch was irrational.

FERC acknowledged the "imperfect correspondence" between the two. JA 611. But it decided that the size-premium adjustment sufficiently improved the capital-asset model's accuracy to justify the mismatch.

We can only judge FERC's logic based on the evidence it had before it. *See FCC v. Prometheus Radio Project*, 141 S. Ct. 1150, 1160 (2021). Here, because FERC had a size-premium adjustment based on unadjusted betas and believed that adjusted betas were the most appropriate input to use in the capital-asset model, it had to choose between "imperfect correspondence" and no size adjustment at all. That is the kind of technical choice to which we are "particularly deferential." *Public Service Commission of Kentucky v. FERC*, 397 F.3d 1004, 1006 (D.C. Cir. 2005) (quoting *Time Warner Entertainment Co. v. FCC*, 56 F.3d 151, 163 (D.C. Cir. 1995)). We do not find it arbitrary and capricious.

3

That same logic persuades us to reject the challenge to FERC's decision to combine adjusted betas based on the New York Stock Exchange with an expected return based on the S&P 500. Here, too, FERC acknowledged the "imperfect correspondence" between the New York Stock Exchange and the S&P 500. JA 873. But FERC concluded that it would not be reasonable to calculate an expected return using all 2,800 companies in the New York Stock Exchange. And no party provided adjusted betas from the appropriate time frame based on the S&P 500. It was not arbitrary and capricious for FERC to do the best it could with the data it had. *See Prometheus*, 141 S. Ct. at 1160.[8]

C

From there, the customers level an array of challenges to FERC's creation of presumptively just and reasonable ranges at step one of the Section 206 analysis. Recall, if you'll suffer another reminder, that FERC created ranges within the zone of reasonableness based on the company's risk profile to analyze the step-one question of whether an existing rate is unjust and unreasonable. Rates within the appropriate range are presumed to be just and reasonable.

1

First, the customers argue that we did not require FERC to adopt its presumption scheme when we vacated FERC's New

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[8] In a more recent proceeding FERC did have access to adjusted betas based on the S&P 500, so it used them. *Constellation Mystic Power, LLC*, 176 FERC ¶ 61,019, 61,102 (2021).

England opinion in *Emera Maine*. *See* 854 F.3d 9 (D.C. Cir. 2017). That is true, but it misses the point. FERC is entitled to adopt any methodology it believes will help it ensure that rates are just and reasonable, so long as it doesn't adopt that methodology in an arbitrary and capricious manner. *See Southern California Edison Co. v. FERC*, 717 F.3d 177, 182 (D.C. Cir. 2013).

As FERC recognized, our opinion in *Emera Maine* held that FERC had failed to sufficiently explain why the existing rate was unjust and unreasonable at step one of the Section 206 inquiry. 854 F.3d at 26-27. We had explained that "the zone of reasonableness creates a broad range of potentially lawful" Returns, such that FERC needed to do more than identify a single new Return that it preferred. *Id.* at 26. So in response, FERC developed this new framework to more effectively verify that an existing rate is in fact unjust and unreasonable. The customers have provided no persuasive reason to think that doing so was arbitrary and capricious.

2

Second, the customers contend that the presumption scheme unlawfully heightens the burden of proof that they must carry. It doesn't. The presumption is just that: a presumption. FERC provided several types of evidence that could rebut it, from non-utility stock prices to expert testimony.

3

Next, the customers claim that FERC created an irrebuttable presumption in this particular case by using the Return it had set in the first-complaint proceeding to adjudicate the second complaint. Their argument has two layers. First, they argue that it was unlawful for FERC to use the new Return (the 10.02% it had just set earlier in Opinion 569-A) instead of the pre-complaint 12.38% Return they had originally challenged. Second, they say that even if that was lawful, FERC's adjudication of both proceedings in one order denied them any meaningful opportunity to rebut the presumption because they didn't know what presumptively just and reasonable number they had to rebut. They are wrong on both fronts.

To the first point, Section 206 says:

> **Whenever the Commission**, after a hearing held upon its own motion or upon complaint, **shall find that any rate**, charge, or classification, demanded, observed, charged, or collected by any public utility for any transmission or sale subject to the jurisdiction of the Commission, or that any rule, regulation, practice, or contract affecting such rate, charge, or classification **is unjust, unreasonable, unduly discriminatory or preferential, the Commission shall determine the just and reasonable rate**, charge, classification, rule, regulation, practice, or contract **to be thereafter observed and in force**, and shall fix the same by order.

16 U.S.C. § 824e(a) (emphases added).

Two aspects of the statute show that FERC was correct to use the 10.02% Return it had set earlier in Order 569-A when it resolved the first complaint.[9] First, the statute uses the present-tense verb "is," which means that FERC must look to the current Return at the time of decision. *See Carr v. United*

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[9] Although the statute uses "rate," in this case the only component of the rate that was at issue was the Return, so that is what FERC focused on.

States, 560 U.S. 438, 447-48 (2010) (explaining the importance of verb tense). Second, the statute commands that FERC set a Return "to be thereafter observed and in force." Once FERC sets a new Return in the first proceeding, it must observe and enforce that Return until it lawfully changes, including in ongoing proceedings.

On top of those points, the customers' theory would upend the strict fifteen-month refund limit that Congress placed on Section 206 proceedings. 16 U.S.C. § 824e(b). If customers can just file new complaints challenging the same Return every fifteen months, the limit accomplishes nothing. Absent some clearer indication of congressional intent, we will "not assume that Congress left such a gap in its scheme." *Jackson v. Birmingham Board of Education*, 544 U.S. 167, 181 (2005).[10]

To the customers' second argument, there is some awkwardness in the fact that FERC chose to act on the first and second complaints in one order. But FERC has "broad discretion to manage" its docket. *Florida Municipal Power Agency v. FERC*, 315 F.3d 362, 366 (D.C. Cir. 2003) (cleaned up). And the customers do not point to any evidence that they would have marshaled to challenge the new 10.02% Return that they did not offer to challenge the old 12.38% one. So on these particular facts, we cannot conclude that FERC abused its broad discretion.

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[10] This should not be read to endorse the transmission owners' argument that customers cannot file successive complaints. FERC has an explanation for allowing successive complaints that it says reconciles the practice with this provision. Because we decide that FERC was correct to use the Return from the first complaint to adjudicate the second, and therefore that FERC was right to dismiss the second complaint, we need not decide this issue.

4

The customers' final step-one challenge says that the presumption unlawfully creates a difference between Section 205 proceedings and Section 206 proceedings. But Congress required that difference. "Section 206's procedures are entirely different and stricter than those of section 205." *See Emera Maine*, 854 F.3d at 24 (cleaned up).

D

Next, remember that for step two of the Section 206 analysis — setting the new just and reasonable rate — FERC returned to its customary practice of using the midpoint of the zone of reasonableness. The customers argue that it should have set aside the midpoint in favor of the median.[11]

But we have already held that FERC can reasonably use the midpoint of the zone of reasonableness when setting a Return for "a diverse group of companies." *Public Service Commission*, 397 F.3d at 1011. That decision, *Public Service Commission of Kentucky v. FERC*, even involved MISO. *Id.* at 1006.

The customers try to cabin *Public Service Commission* to Return analyses where FERC uses a proxy group made up of companies from within the same region as the transmission owners. But that was not the reason FERC chose the midpoint in *Public Service Commission*, so it is not the reason we deemed FERC's choice reasonable. *Id.* There, FERC focused

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[11] For a series of numbers, the midpoint is the halfway point between the biggest number and the smallest number (calculated by adding the two together and dividing by two). The median is the middle number in the series. So, for example, the midpoint of 1, 3, 5, 9, and 11 is 6. The median is 5.

on "the rate's across-the-board applicability to MISO" transmission owners. *Id.* at 1011. FERC did the same here, so precedent requires that we reach the same result.

E

Finally, the customers challenge FERC's about-face on the risk-premium model (Model 4). As FERC applied it in this proceeding, the model compares past Returns that FERC itself set or approved to contemporaneous corporate-utility-bond rates. FERC took the difference between those rates and added it to the current corporate-utility-bond rate. So for example, if the past corporate-utility-bond rates were always 6% and Return rates were always 10%, FERC would take that difference (4%) and add it to the current corporate-utility-bond rate. If the current corporate-utility-bond rate is 5%, the new Return would be 9%.[12] *See* James Bonbright, Albert Danielsen & David Kamerschen, *Principles of Public Utility Rates* 323 (2d ed. 1988) (offering a similar example).

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[12] This explanation omits one step that no one questions, which is therefore not relevant to our analysis. Before FERC adds the risk premium it calculated from the past corporate-utility-bond rates and Returns to the current bond rate, it adjusts that number to "reflect the tendency of risk premiums to rise as interest rates fall." JA 249. Basically, it calculates the inverse relationship between bond yields and risk premiums to determine how much higher the risk premium needs to be to incentivize investment when the bond rate is lower. Here, for example, the calculation determined that for every 1% bond rates dropped, investors required an extra .77% Return. So when the bond rate had dropped by 1.35%, FERC multiplied 1.35 and .77 to get an adjustment of 1.04%, which it added to the average difference between the past bond rates and past FERC-allowed Returns. It then added the sum of those numbers to the current corporate-utility-bond rate to get the value for what the new Return should be.

In FERC's first rehearing order, Opinion 569, it concluded that any "additional robustness" the risk-premium model added to its methodology was "outweighed by the disadvantages of its deficiencies." JA 628. It then spent several pages demonstrating the impressive extent of those deficiencies. For example:

- The model, at least as applied in this case, "defies general financial logic" by keeping the Return stable regardless of capital-market conditions. JA 629.
- There was insufficient evidence in the record to conclude that investors rely on this kind of risk-premium model.
- The model is less accurate than the discounted-cash-flow model (Model 1) or capital-asset model (Model 2) because it relies on previous Return determinations that may not have been market-based.
- It "is largely redundant with" the capital-asset model (Model 2), so adding it would overweight risk-premium methodologies against the long-used discounted-cash-flow model (Model 1). JA 628.
- It presents "particularly direct and acute" circularity problems because it uses past FERC-allowed Returns to set the new ones. JA 628.

And those are just from the first two pages of criticisms. Suffice it to say that in Opinion 569, FERC found the risk-premium model quite defective.

Then, in Opinion 569-A — on rehearing of Opinion 569 — FERC changed its tune. It decided "that the defects of the Risk Premium model do not outweigh the benefits of model diversity" after all. JA 882.

FERC is, of course, entitled to change its mind. *FCC v. Fox Television Stations, Inc.*, 556 U.S. 502, 515 (2009). But to do so, it must provide a "reasoned explanation" for its decision to disregard "facts and circumstances that" justified its prior choice. *Id.* at 515-16. Here, FERC failed to do that.

First and worst, FERC did not explain how its changes brought the analysis into line with "general financial logic." JA 629. FERC can't ignore the basic financial principles that otherwise undergird its analysis — at least not without a compelling explanation. *See Tennessee Gas Pipeline Co. v. FERC*, 926 F.2d 1206, 1210-11 (D.C. Cir. 1991); *id.* at 1213 (Thomas, J., concurring) ("At the very least, FERC was obliged to offer some convincing evidence in support of its facially implausible economic assumption").

Second, FERC failed to adequately explain why it no longer mattered that investors don't use this model. Instead, it simply noted that investors expect a premium on a stock investment over a bond investment, and that investors track the Returns FERC allows. Both statements are true, but neither offers a persuasive reason to think that the risk-premium model as FERC applied it here offers meaningful insight into investor behavior.

Third, FERC failed to meaningfully address its own concerns about the risk-premium model's circularity. Instead, it just said that "all of the models contain some circularity" and decided that averaging the risk-premium model's results with the other models' results helps mitigate the circularity. JA 882. That explanation doesn't meaningfully engage with the "particularly direct and acute" circularity problems presented by using old rates to set new ones. JA 628.

Finally, FERC never engaged with its earlier concerns about the overweighting of risk-premium theory. It briefly discussed the redundancy of the capital-asset and risk-premium models (Models 2 and 4), saying that because they used different inputs to calculate the risk premium they were not too redundant to use. But it failed to reckon with its own serious concerns about "variations of the risk premium model" receiving twice the weight of the discounted-cash-flow model (Model 1) that FERC "has long used and, over time, refined." JA 628. An agency ignoring its own qualms is not reasoned decisionmaking.

* * *

FERC failed to offer a reasoned explanation for its decision to reintroduce the risk-premium model (Model 4) after initially, and forcefully, rejecting it. Because FERC adopted that significant portion of its model in an arbitrary and capricious fashion, the new Return produced by that model cannot stand. We therefore vacate FERC's orders.

IV

In addition to the customers' challenge to FERC's new Return methodology, the customers challenged FERC's determination that it could not order a refund for the second complaint's refund period. But to the extent that any of that argument survives our earlier rejection of the customers' statutory basis for their "irrebuttable presumption" argument, *see* Part III.C.3, we decline to opine on the customers' argument because we have already granted their petition to vacate FERC's rate orders. *See Southwest Airlines Co. v. FERC*, 926 F.3d 851, 859 (D.C. Cir. 2019).

For the same reason, we dismiss the transmission owners' petitions challenging those now-vacated orders. They had challenged FERC's right to require transmission owners to pay the difference between the amount FERC ordered in its first decision and the rate it ordered on rehearing. But because we vacate FERC's rehearing order, there is no longer a new rate to base a refund on.

Until FERC sets a new Return, a decision on the refund issue will not alter the parties' rights and obligations. Nor will a decision on the transmission owners' argument that FERC lacked the authority to adjudicate the second complaint. When "it is not necessary to decide more, it is necessary not to decide more." *PDK Laboratories, Inc. v. DEA*, 362 F.3d 786, 799 (D.C. Cir. 2004) (Roberts, J., concurring in part and in the judgment).

V

We grant the customers' petitions for review, dismiss the transmission owners', vacate the underlying orders, and remand for FERC to reopen proceedings.

10-Oct-2023 | 18:28 EDT

Cascade Natural Gas 'BBB+' Ratings Affirmed, Outlook Developing; SACP Revised Downward On Weaker Financial Measures

- Cascade Natural Gas Corp.'s stand-alone financial measures have remained weak for its stand-alone credit profile (SACP), reflecting higher debt leverage because of an extended recovery of elevated natural gas costs. The company has also suffered from significant regulatory lag, with earned returns consistently lagging authorized levels for several years.
- In our view, Cascade remains a core subsidiary to parent MDU Resources Group Inc.
- As a result, we affirmed our ratings on Cascade, including our 'BBB+' issuer credit rating on the company and our 'BBB+' issue-level rating on its medium-term notes.
- We revised our SACP on Cascade downward to 'bb+' from 'bbb', reflecting our expectations that its stand-alone financial measures will remain consistently below previous levels.
- The developing rating outlook on Cascade is consistent with the outlook on parent MDU Resources and reflects the uncertainty regarding the parent's strategic review and capital structure plans. We expect Cascade's stand-alone funds from operations (FFO) to debt will reflect 10%-12% through 2024.

DALLAS (S&P Global Ratings) Oct. 10, 2023—S&P Global Ratings today took the rating actions listed above.

Extended recovery of elevated natural gas costs has resulted in higher debt leverage. In early 2023, Cascade funded its elevated natural gas costs with proceeds from the issuance of a $150 million 364-day term loan, resulting in weaker stand-alone financial measures. We expect that it will likely take several years for it to fully recover these elevated costs from customers. We therefore expect the company's financial performance will remain consistently below our previous expectations, reflecting FFO to debt greater than 15%, despite the company earning a carrying charge on these higher costs. We now expect stand-alone FFO to debt of 10%-12% through 2024. As such, we revised Cascade's financial risk profile to aggressive from significant and its SACP to 'bb+' from 'bbb'.

The company's earned returns have consistently lagged authorized levels.Cascade's financial performance has suffered from weaker regulatory outcomes and significant regulatory lag. In August 2022, Cascade was authorized a $7.2 million rate increase by the Washington Utilities and Transportation Commission (WUTC) based on a 2020 year-end test period. This reflects about 20 months of regulatory lag. Before this, in May 2021, the WUTC ordered Cascade to reduce rates by about $400,000, determining that the company had failed to demonstrate the need for higher rates and negating the $7.4 million revenue increase sought initially. Weaker regulatory outcomes and consistent regulatory lag have resulted in financial performance that has lagged peers in the state, as demonstrated by stand-alone FFO to debt of about 12.5% for 2020-2022. Our revised base case incorporates FFO to debt of 10%-12% through 2024.

We continue to consider Cascade a core subsidiary of parent MDU Resources. Our assessment reflects our view that Cascade is highly unlikely to be sold, as it represents a significant portion of MDU Resources' utility segment (almost 25% of utility EBITDA). We also believe Cascade is integral to MDU Resources' overall group strategy of becoming a pure-play, regulated energy delivery company. Customer growth is also highest within Cascade's service territory compared to its affiliate peers. We therefore believe Cascade possesses a strong, long-term commitment from senior management, given its relative size and strategic importance to the group.

The developing outlook on Cascade is consistent with the outlook on parent MDU Resources. This reflects the uncertainty regarding its strategic review and capital structure plans. We continue to consider Cascade as a core subsidiary of MDU Resources and expect that Cascade's stand-alone FFO to debt will reflect 10%-12% through 2024. We could affirm our ratings on Cascade and revise the outlook to stable over the next 18 months if we did the same for MDU Resources.

We could lower the ratings on Cascade over the next 18 months by one or more notches if we lowered the ratings on MDU Resources or if we lowered our assessment of Cascade's group status.

We could raise the ratings on Cascade over the next 18 months if we raised our ratings on MDU Resources.

Related Criteria

- General Criteria: Environmental, Social, And Governance Principles In Credit Ratings, Oct. 10, 2021
- General Criteria: Group Rating Methodology, July 1, 2019
- Criteria | Corporates | General: Corporate Methodology: Ratios And Adjustments, April 1, 2019
- Criteria | Corporates | General: Reflecting Subordination Risk In Corporate Issue Ratings, March 28, 2018
- Criteria | Corporates | General: Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Dec. 16, 2014
- General Criteria: Country Risk Assessment Methodology And Assumptions, Nov. 19, 2013
- General Criteria: Methodology: Industry Risk, Nov. 19, 2013
- Criteria | Corporates | Utilities: Key Credit Factors For The Regulated Utilities Industry, Nov. 19, 2013
- Criteria | Corporates | General: Corporate Methodology, Nov. 19, 2013
- General Criteria: Methodology: Management And Governance Credit Factors For Corporate Entities, Nov. 13, 2012
- General Criteria: Principles Of Credit Ratings, Feb. 16, 2011

European Endorsement Status

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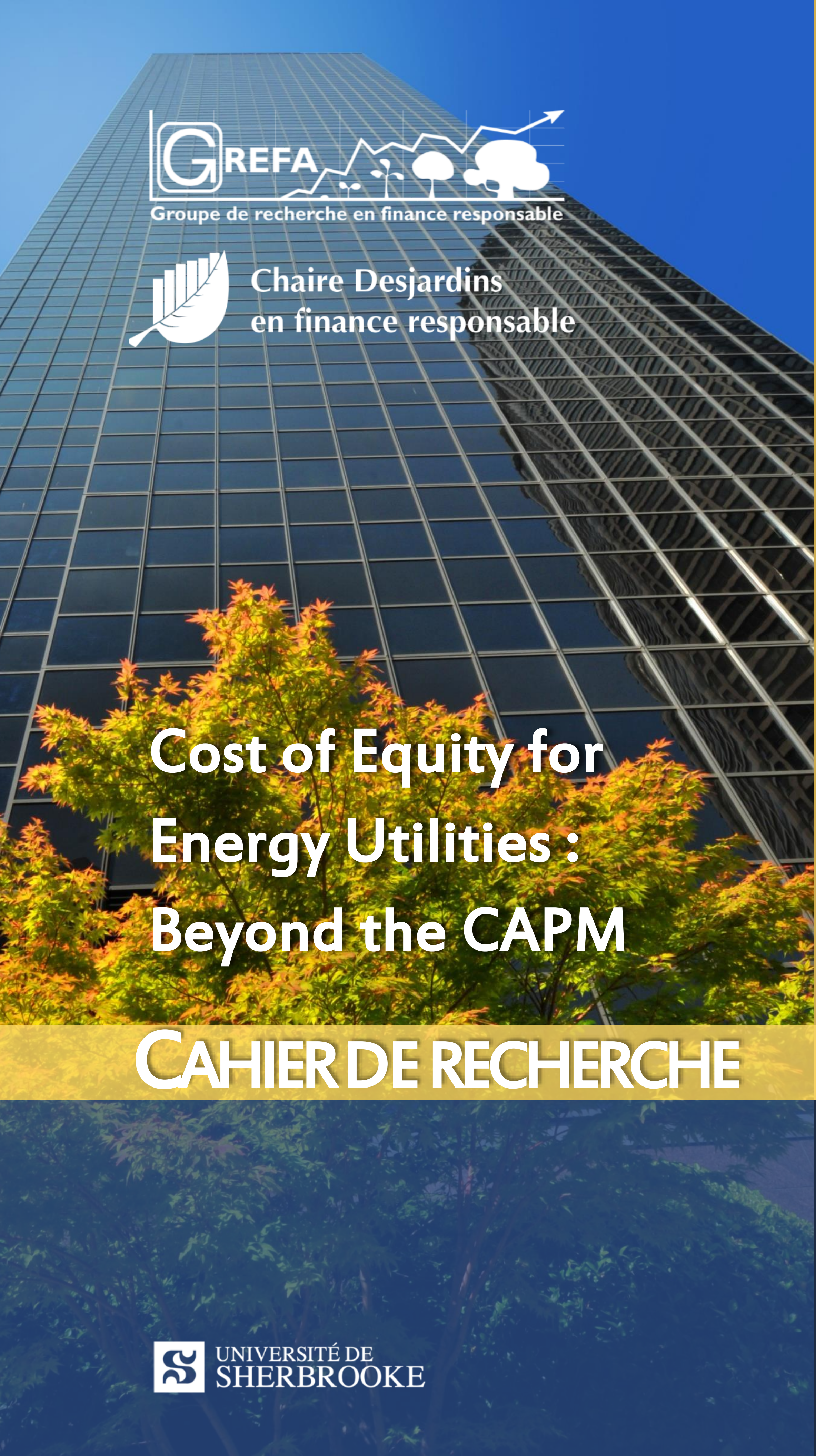

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Cost of Equity for Energy Utilities : Beyond the CAPM

CAHIER DE RECHERCHE

par

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COST OF EQUITY FOR ENERGY UTILITIES: BEYOND THE CAPM[*]

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Draft: February 2008

Abstract

The Capital Asset Pricing Model (CAPM) is often used to estimate the required rate of return of energy utilities in regulatory cases. This paper investigates the appropriateness of this choice in light of the large body of work questioning the empirical validity of the model. Consistent with its well documented misevaluation of low-beta, value-oriented investments, we find that the CAPM significantly underestimates the cost of equity of Canadian and American energy utilities compare to its historical value. We then consider two models developed in the finance literature to address some of the empirical problems of the CAPM. Our results indicate that these models are better specified than the CAPM for estimating the cost of equity of energy utilities.

JEL Classifications: G12, L51, L95, K23

Keywords: Cost of Capital, Rate of Returns, Energy Utilities, Asset Pricing Models

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Abstract

The Capital Asset Pricing Model (CAPM) is often used to estimate the required rate of return of energy utilities in regulatory cases. This paper investigates the appropriateness of this choice in light of the large body of work questioning the empirical validity of the model. Consistent with its well documented misevaluation of low-beta, value-oriented investments, we find that the CAPM significantly underestimates the cost of equity of Canadian and American energy utilities compare to its historical value. We then consider two models developed in the finance literature to address some of the empirical problems of the CAPM. Our results indicate that these models are better specified than the CAPM for estimating the cost of equity of energy utilities.

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1. Introduction

An important aspect of the regulatory process for energy utilities is the determination of their equity rate of return. This return, also known as the cost of equity capital, represents the expected remuneration of the shareholders of the utilities, and is thus related to their ability to attract and retain capital. It is a crucial component of their total cost of capital, which is central to their investment policy and serves as a basis for setting up the rates to their customers. The purpose of this paper is to highlight the problems of the most commonly used model to determine the equity rate of return for energy utilities and to propose two alternative models that empirically improve on the estimation.

Regulatory bodies, like the National Energy Board in Canada or the Federal Energy Regulatory Commission in the United States, have the mandate to set the equity rate of return so that it is fair and reasonable. Specifically, the return should be comparable to the return available from the application of the capital to other enterprises of like risk. Traditionally, the regulated return was set through hearings, but since the 1990s, numerous boards have adopted an annual mechanism know as a “rate of return formula” or a “rate adjustment formula”. The use of rate adjustment formulas is particularly prevalent in Canada since the landmark March 1995 decision by the National Energy Board (Decision RH-2-94), which sets the stage for the widespread adoption of closely related formulas by provincial regulators.

Most rate adjustment formulas use a method known as the Equity Risk Premium method.[1] This method can be summarized as calculating a utility’s equity rate of return as the risk-free rate of return plus a premium that reflects its risk. The risk-free rate is usually related to the yield on a long-term government bond. The risk premium is obtained from the Capital Asset Pricing Model (CAPM) of Sharpe (1964) and Lintner (1965), a classic model of capital market equilibrium. It is equal to the utility’s beta, a measure of its systematic risk, multiplied by the market portfolio risk premium. The Equity Risk Premium method has a number of advantages. First, it is supported by a solid theoretical foundation in the academic literature. Second, it can be estimated based on stock market returns, thereby making it more objective than the other

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[1] There exist other methods for estimating the rate of return, most notably the Comparable Earnings method and the Discounted Cash Flows method. These methods are generally not directly incorporated in the rate adjustment formulas.

methods, and relating it to current market conditions. Third, it is relatively simple to apply and requires data that can be obtained easily.

The Equity Risk Premium method is not, however, without shortcomings. Arguably its most criticized feature is the use of the CAPM as the basis to determine the risk premium. While the CAPM is one of the most important developments in finance, research over the last forty years has produced a large body of work critical of the model. On the theoretical side, Cochrane (1999) summarizes the current most prevalent academic view: "In retrospect, it is surprising that the CAPM worked so well for so long. The assumptions on which it is built are very stylized and simplified."[2] For example, at least since Merton (1973), it is recognized that factors, state variables or sources of priced risk beyond the movements in the market portfolio (the only risk factor in the CAPM) might be needed to explain why some risk premiums are higher than others. On the empirical side, the finance literature abounds with CAPM deficiencies (so-called "anomalies"). Fama and French (2004) review this literature to highlight that the CAPM is problematic in the estimation of the risk premium of low-beta firms, small-capitalisation firms and value (or low-growth) firms. While these problems have been well documented in the finance literature, their effects have not yet been fully explored in the determination of the rate of return for the utilities sector.

Considering the importance of the CAPM in determining the regulated equity rate of return, the objectives of this paper are two-folds. First, we re-examine the use of the model in the context of energy utilities to determine if it is problematic. As energy utilities are typically low-beta, value-oriented investments, the finance literature suggests that the model will have difficulties in estimating their risk premiums. We analyze the issue empirically by estimating the model and its resulting risk premiums for a sample of Canadian and American energy utilities mostly related to the gas distribution sector, and by testing for the presence of significant differences between the model's risk premium estimates and the historical ones.

Second, we implement two alternative models that are designed to circumvent some of the empirical problems of the CAPM. The first alternative is a three-factor model proposed by Fama and

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[2] Cochrane (1999), p. 39.

French (1993) (the Fama-French model hereafter). This model has been used to estimate the cost of equity by Fama and French (1997) for general industrial sectors and by Schink and Bower (1994) for the utilities sector in particular. The second alternative is a modified CAPM that includes the adjustments proposed by Blume (1975) and Litzenberger, Ramaswamy and Sosin (1980) (the Adjusted CAPM hereafter). The Fama-French model and the Adjusted CAPM provide useful comparisons with the CAPM on the estimation of the risk premiums of energy utilities.

Our empirical results can be summarized as follows. First, the CAPM significantly underestimates the risk premiums of energy utilities compare to their historical values. The underestimations are economically important, with annual averages of respectively 4.5% and 6.2% for the Canadian and American gas utilities we consider, and are consistent with the finance literature on the mispricing of low-beta, value-oriented stocks. Second, the Fama-French model and the Adjusted CAPM are both able to provide costs of equity that are not significantly different from the historical ones. Our results show that the value premium, in the case of the Fama-French model, and a bias correction, in the case of the Adjusted CAPM, are important to account for the elimination of the CAPM underestimations. Both models suggest average risk premiums between 4% and 8% for gas utilities portfolios, and are found relevant at the individual utility level as well as at the general utilities sector level.

Overall, we conclude that the CAPM is problematic in estimating econometrically the cost of equity of energy utilities. The Fama-French model and the Adjusted CAPM are better specified for this purpose as they reduce considerably the estimation errors. These models could thus be considered as valid alternatives to the CAPM in the Equity Risk Premium method employed by regulatory bodies.

The rest of the paper is divided as follows. The next section presents our sample of energy utilities and reference portfolios. The third, fourth and fifth sections examine the risk premium estimates with the CAPM, the Fama-French model and the Adjusted CAPM, respectively. Each section provides an overview of the model, presents its empirical estimation and results, and discusses the implications of our findings. The last section concludes.

2. Sample Selection and Descriptive Statistics

This section examines the sample of firms and portfolios for our estimation of the cost of equity of energy utilities. We focus on the gas distribution sector to present complete sector-level and firm-level results, but we also consider utilities indexes to ensure the robustness to other utilities. We provide Canadian and American results for comparison, as both energy markets are relatively integrated and investors might expect similar returns. We first discuss sample selection issues and then present descriptive statistics.

2.1. Sample Selection

Two important choices guide our sample selection process. First, we use monthly historical data in order to have sufficient data for estimating the parameters and test statistics, while avoiding the microstructure problems of the stock markets (low liquidity for numerous securities, non-synchronization of transactions, etc.) in higher frequency data.[3] We then annualized our results for convenience, as the regulated rate of return is an annual figure. Second, we emphasize reference portfolios (such as sector indexes) over individual firms. Reference portfolios reduce the potentially large noise (or diversifiable risk) in the stock market returns of individual firms. They allow for an increased statistical accuracy of the estimates, an advantage recognized since (at least) Fama and MacBeth (1973), and alleviate the problem that we do not observe the returns on utilities directly and must rely on utility holding companies.

To represent the gas distribution sector in Canada and the U.S., we use a published index and a constructed portfolio for each market. The independently-calculated published indexes are widely available and consider the entire history of firms having belonged to the gas distribution sector. The constructed portfolios use the most relevant firms at present in the gas distribution or energy utility sector. The data collection also allows an examination of the robustness of our results at the firm level. The resulting four gas distribution reference portfolios are identified and described below.

- *DJ_GasDi*: A Canadian gas distribution index published by Dow Jones, i.e. the "Dow Jones Canada Gas Distribution Index." The firms in the index are weighted by their market value. Monthly returns (180) are available from January 1992 to December 2006;

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[3] See Fowler, Rorke and Jog (1979, 1980) for an analysis of these problems in the Canadian stock markets.

- *CAindex*: An equally-weighted constructed portfolio formed of 13 Canadian energy utilities, most with activities that are related to the gas distribution sector, i.e. ATCO Ltd., Algonquin Power Income Fund, Canadian Utilities Limited, EPCOR Power, Emera Incorporated, Enbridge Inc., Fort Chicago Energy Partners, Fortis Inc., Gaz Métro Limited Partnership, Northland Power Income Fund, Pacific Northern Gas, TransAlta Corporation and TransCanada Pipelines.[4] Monthly returns (263) are available from February 1985 to December 2006;
- *DJ_GasUS*: A U.S. gas distribution index published by Dow Jones, i.e. the "Dow Jones US Gas Distribution Index." The firms in the index are weighted by their market value. Monthly returns (180) are available from January 1992 to December 2006;
- *USindex*: An equally-weighted constructed portfolio formed of nine U.S. firms whose activities are heavily concentrated in local gas distribution, i.e. AGL Resources Inc., Atmos Energy Corp., Laclede Group, New Jersey Resources Corp., Northwest Natural Gas Co., Piedmont Natural Gas Co., South Jersey Industries, Southwest Gas Corp. and WGL Holdings Inc. Monthly returns (407) are available from February 1973 to December 2006.

To confirm the validity of our analysis to other energy utilities, we also consider four utilities reference portfolios, which consist of the general indexes of the utilities sector described below.

- *DJ_Util*: A Canadian utilities index published by Dow Jones, i.e. the "Dow Jones Canada Utilities Index." The firms in the index are weighted by their market value. Monthly returns (180) are available from January 1992 to December 2006;
- *TSX_Util*: A Canadian utilities index published by S&P/TSX, i.e. the "S&P/TSX Utilities Index." The firms in the index are weighted by their market value. Monthly returns (228) are available from January 1988 to December 2006;

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[4] We also considered AltaGas Utility Group, Enbridge Income Fund, Westcoast Energy, Nova Scotia Power and Energy Savings Income Fund. We did not retain the first four because they had a returns history of less than 60 months. We eliminated the last one because it is a gas broker and its average monthly return of more than 3% was a statistical outlier. Our results are robust to variations in the formation of the CAindex portfolio, like the inclusion of these five firms or the exclusion of income funds and limited partnerships.

- *DJ_UtiUS*: A U.S. utilities index published by Dow Jones, i.e. the "Dow Jones US Utilities Index." The firms in the index are weighted by their market value. Monthly returns (180) are available from January 1992 to December 2006;
- *FF_Util*: A U.S. utilities index formed by Profs. Fama and French, or the University of Chicago and Dartmouth College, respectively. The firms in the index are weighted by their market value. Monthly returns (407) are available from February 1973 to December 2006.

According to their availability, the reference portfolio return series have different starting dates (resulting in samples with 180 to 407 observations). In our estimation of the parameters, we keep the maximum number of available observations for each series. Fama and French (1997) find that such a choice results in costs of equity more precisely estimated and with more predictive ability than costs of equity obtained from rolling five-year estimation windows, a common choice in practice. The data are collected from the Canadian Financial Markets Research Center (CFMRC), Datastream, the web site of Prof. French[5] and the web site of Dow Jones Indexes[6].

2.2. Descriptive Statistics

Descriptive statistics (number of observations, mean, standard deviation, minimum and maximum) for the series of monthly returns are presented in Table 1. Panel A shows the results for the 13 Canadian energy utilities and their equally-weighted portfolio (CAindex). Panel B shows the results for nine U.S. firms whose activities are heavily concentrated in gas distribution and their equally-weighted portfolio (USindex). Panel C shows the statistics for Canadian and U.S. indexes for the utilities sector (DJ_Util, DJ_UtilUS, TSX_Util and FF_Util) and the gas distribution sub-sector (DJ_GasDi and DJ_GasUS).[7]

INSERT TABLE 1 HERE.

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[5] http://mba.tuck.dartmouth.edu/pages/faculty/ken.french/data_library.html.

[6] http://www.djindexes.com/mdsidx/index.cfm?event=showtotalMarketIndexData&perf=Historical%20Values.

[7] The returns from August to November 2001 of the Dow Jones U.S. indexes are strongly influenced by the Enron debacle, which started with the resignation of its CEO, Jeffrey Skilling, on August 14, 2001 and ended with the bankruptcy of the company on December 2, 2001. During those four months, the DJ_GasUS and DJ_UtiUS indices lost 68.9% and 16.2% of their value, respectively. By comparison, the equally-weighted portfolio of U.S. gas distributors – USindex – gained 1.2% and the Fama-French utilities index – FF_Util – lost 6.2 %. In order to soften the impact of that statistical aberration (caused by an unprecedented fraud) on the estimation of the risk premium, the returns from August to November 2001 of DJ_GasUS and DJ_UtilUS are replaced by those of USindex and FF_Util, respectively.

For the Canadian energy utilities in our sample, the monthly average return of all 13 firms is 1.0% with a standard deviation of 3.1%. The Dow Jones Canada Gas Distribution Index, the Dow Jones Canada Utilities Index and the S&P/TSX Utilities Index have mean returns of 1.2%, 0.7% and 1.0%, respectively. The monthly average return of the nine U.S. local gas distribution utilities is 1.2% with a standard deviation of 4.1%. The Dow Jones US Gas Distribution Index, the Dow Jones US Utilities Index and the Fama-French U.S. Utilities Index show mean returns of 1.2%, 0.9% and 1.0%, respectively. Correlations between the four gas distribution reference portfolios (not tabulated) are between 0.29 and 0.80. These correlations indicate that the portfolios are not perfect substitutes but capture some common elements of the gas distribution sector. We next start our analysis of the equity risk premium estimation models.

3. Equity Risk Premium with the CAPM

This section examines the use of the Capital Asset Pricing Model (CAPM) for estimating the rate of return for energy utilities. The CAPM is the model the most often associated with the Equity Risk Premium method that is the basis of the rate adjustment formulas of regulatory bodies. We first present the model and its relevant literature. Then we estimate the model for our sample of energy utilities. Finally, we discuss the implications of our findings.

3.1. Model and Literature

The CAPM is a model proposed by Sharpe (1964) and Lintner (1965) in which the expected equity return or cost of equity for a gas utility is given by

$$E(R_{GAS}) = R_f + \beta \times \lambda_m ,$$

where R_f is the risk-free rate, β is the firm's beta or sensitivity to the market returns and λ_m is the market risk premium. In this model, a higher beta results in a higher risk premium.

The CAPM is the best known model of expected return. In spite of its undeniable importance in the field of finance, it has long been rejected by numerous empirical tests in the academic literature. The empirical rejections start with the first tests (Black, Jensen and Scholes (1972), Fama and MacBeth (1973) and Blume and Friend (1973)) that find that the relation between beta and average return is flatter than predicted by the model. They continue with the discovery of numerous "anomalies" (like the price-to-earnings effect of Basu, 1977, the size effect of Banz, 1981, etc.). Finally, in the 1990s, based on high-impact articles, including Fama and French (1992, 1993, 1996a and 1996b), Jegadeesh and Titman (1993) and Jagannathan and Wang (1996), the academic profession reaches a relative consensus that the CAPM is not valid empirically. In Canada, like elsewhere in the world, the literature reaches similar conclusions (see Morin, 1980, Bartholdy, 1993, Bourgeois and Lussier, 1994, Elfakhani, Lockwood and Zaher, 1998, L'Her, Masmoudi and Suret, 2002, 2004.).

A complete review of the literature on the problems of the CAPM is beyond the scope of this paper. It is nevertheless important to point out the two characteristics of energy utilities that suggest the CAPM might be problematic in estimating their equity return. First, energy utilities have typically low betas, significantly below one. Second, they are known as value investments, in the sense that they have high earnings-to-price, book-to-market, cash flows-to-price or dividend-to-price ratios. In a summary article requested for a symposium on the 40th anniversary of the CAPM, Fama and French (2004) highlight the result of using the model to estimate the cost of equity capital for firms with these two characteristics:

> "As a result, CAPM estimates of the cost of equity for high beta stocks are too high (relative to historical average returns) and estimates for low beta stocks are too low (Friend and Blume, 1970). Similarly, if the high average returns on value stocks (with high book-to-market ratios) imply high expected returns, CAPM cost of equity estimates for such stocks are too low."[8]

As Fama and French (2004) indicate, the low-beta and value characteristics of energy utilities will probably lead the CAPM to estimate a rate of return that is too low. We next examine whether this undervaluation in fact exists in our sample of reference portfolios and utilities.

3.2. Risk Premium Estimates

This section empirically estimates the risk premium with the CAPM using the previously described Canadian and U.S. monthly data. More specifically, we estimate the model using the time-series regression approach pioneered by Black, Jensen and Scholes (1972) with the following equation:

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[8] Fama and French (2004), p. 43-44.

$$R_{GAS,t} - R_{f,t} = \alpha_{GAS} + \beta \times \lambda_{m,t} + \varepsilon_{GAS,t},$$

where $\lambda_{m,t} = R_{m,t} - R_{f,t}$ is the return on the market portfolio in excess of the risk-free return and $\varepsilon_{GAS,t}$ is the mean-zero regression error, at time *t*. In this equation, the CAPM predicts that the alpha (the intercept) is zero ($\alpha_{GAS} = 0$) and the gas utility risk premium is $E(R_{GAS,t} - R_{f,t}) = \beta \times E(\lambda_{m,t})$. An alpha different from zero can be interpreted as the risk premium error of the CAPM (see Pastor and Stambaugh, 1999). A positive alpha indicates the CAPM does not prescribe a large enough risk premium compare to its historical value (an underestimation), whereas a negative alpha indicates the CAPM prescribes a risk premium that is too large (an overestimation). It is therefore possible to determine the risk premium error of the CAPM for energy utilities based on the estimates of the alpha.

We use Hansen's (1982) Generalized Method of Moments technique in order to estimate jointly the parameters α_{GAS} and β of the model and the market risk premium $E(\lambda_{m,t})$. As Cochrane (2001, Section 12.1) shows, this method has the necessary flexibility to correct the results for possible econometric problems in the data.[9] We take the monthly returns on portfolios of all listed securities weighted by their market value for the market portfolio returns and on the Treasury bills for the risk-free returns.[10] The annualized mean market risk premiums are 5.2% for Canada from February 1985 to December 2006 and 6.0% for the U.S. from February 1973 to December 2006.

Table 2 shows the results of the regressions using each of the four gas distribution reference portfolios. The estimates of the annualized risk premium error (or annualized α_{GAS}), the beta β and the risk premium $\beta \times E(\lambda_{m,t})$ of the CAPM are presented in Panels A, B and C, respectively. For each estimate, the table also shows its standard error, t-statistic and probability it equals zero (or p-value).

INSERT TABLE 2 HERE.

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[9] All standard errors and statistical tests have been estimated using the Newey and West (1987) method, which takes account of the potential heteroscedasticity and autocorrelation in the errors of the statistical models.

[10] The data sources are CFMRC (until 2004) and Datastream (thereafter) for the Canadian returns and the web site of Prof. French for U.S. returns.

The estimates in Panel A of Table 2 indicate that the risk premium errors are always positive. As the literature reviewed by Fama and French (2004) suggests, the CAPM underestimates the risk premium for the gas distribution reference portfolios. The underestimation is not small – a minimum of 4.52% (for CAindex) and a maximum of 8.43% (for DJ_GasDi) – and is statistically greater than zero for all portfolios. Also, as expected, the underestimation comes with low beta estimates, with values between 0.21 and 0.46 in Panel B. For example, for CAindex, the beta is 0.34 and the annualized risk premium predicted by the CAPM is 1.76%, an underestimation of the historical risk premium $\alpha_{GAS} = 4.52\%$.

To verify the underestimation is not an artefact of the utilization of the reference portfolios and is robust to other energy utilities, Figure 1 shows the risk premium errors for the utilities that make up the CAindex portfolio (Figure 1a), the gas distributors in the USindex portfolios (Figure 1b) and the four utilities reference portfolios (Figure 1c). Once again, the alphas are always positive, with values between 2.1% and 8.9% for the Canadian utilities, between 3.5% and 8.4% for the U.S. gas distributors, and between 2.1% and 5.0% for the utilities reference portfolios. The constantly positive and often significant errors support the notion that the CAPM might not be appropriate for determining the risk premium in the utilities sector.

INSERT FIGURE 1 HERE.

3.3. Discussion

Our results show that the CAPM underestimates the risk premium for the gas distribution sub-sector in particular and for the utilities sector in general. This finding does not however generalize to all sectors. In fact, the empirical literature finds that the CAPM is rejected because it tends to underestimate the risk premium of securities or sectors associated with low-beta, value and small-cap firms, and tends to overestimate the risk premium of securities or sectors associated with high-beta and growth firms (see Fama and French, 1992, 1993, 1996a, 1996b, 1997, 1998). While the magnitude of the underestimation for the utilities is large, it is not unexpected. Figures 2 and 3 in Fama and French (2004) are helpful in this regard. They show visually that the underestimation is about 3% for the lowest beta stocks and about 4% for typical value stocks, resulting in a total underestimation consistent to the ones we estimate.

Our results are similar to numerous scientific studies documenting that the alphas of the CAPM are significantly different from zero, resulting in rejections of the model. As a consequence of these rejections, finance researchers have considered various models that generalized the CAPM as well as various empirical improvements to the estimates of the CAPM. Based on this literature, we explore two alternative ways of estimating the risk premium of energy utilities in the next two sections.

4. Equity Risk Premium with the Fama-French model

The CAPM claims that a single factor, the market portfolio return, can explain expected returns. The most natural extension, called a multifactor model, is to take multiple factors into account. Clearly, if factors other than the market return have positive risk premiums that contribute to explaining expected returns, then the inclusion of those factors should provide a better estimate of the risk premium and potentially eliminate the CAPM errors (see Merton, 1973, and Ross, 1976, for formal theoretical justifications). This section considers the generalization of the CAPM arguably the most empirically promising, a multifactor model by Fama and French (1993). We first describe the model and then use it to estimate the risk premium of energy utilities. We finally discuss the interpretation of our findings.

4.1. Model and Literature

The Fama-French model is a three-factor model developed to capture the anomalous returns associated with small-cap, value and growth portfolios by including risk premiums for size and value. For a gas utility, the expected equity return is given by

$$E(R_{GAS}) = R_f + \beta \times \lambda_m + \beta_{SIZE} \times \lambda_{SIZE} + \beta_{VALUE} \times \lambda_{VALUE},$$

where R_f is the risk-free rate, β, β_{SIZE} and β_{VALUE} are respectively the firm's market, size and value betas, and λ_m, λ_{SIZE} and λ_{VALUE} are respectively the market, size and value risk premiums. The three betas represent sensitivities to the three sources of risk, and the higher are their values, the higher is a firm's risk premium. In cases when the size and value risk factors are not relevant, then the Fama-French model reduces to the CAPM. Theoretical justifications for the size and value premiums are provided by Berk, Green and Naik (1999), Gomez, Kogan and Zhang (2003), and Carlson, Fisher and Giammarino (2004). Fama and French (1993, 1996a) are the two of the most influential empirical tests of the model.

Like the CAPM, the Fama-French model has been used in applications ranging from performance measurement to abnormal return estimation and asset valuation. For the calculation of the cost of equity capital, the model is studied by, among others, Schink and Bower (1994), Fama and French (1997), and Pastor and Stambaugh (1999). It has also proven to be relevant for explaining stock market returns in most countries where it has been examined. For example, in Canada, the model is validated by Elfakhani, Lockwood and Zaher (1998) and L'Her, Masmoudi and Suret (2002). Given that energy utilities are associated with value investments, the Fama-French model has the potential to improve the estimation of their rates of returns. We next assess this possibility for our sample of reference portfolios and utilities.

4.2. Risk Premium Estimates

The risk premium with the Fama-French model is estimated with a methodology that is similar to the one followed for the CAPM using the following equation:

$$R_{GAS,t} - R_{f,t} = \alpha_{GAS}^{FF} + \beta \times \lambda_{m,t} + \beta_{SIZE} \times \lambda_{SIZE,t} + \beta_{VALUE} \times \lambda_{VALUE,t} + \upsilon_{GAS,t},$$

where $\lambda_{m,t} = R_{m,t} - R_{f,t}$ is the return on the market portfolio in excess of the risk-free return, $\lambda_{SIZE,t} = R_{SMALL,t} - R_{LARGE,t}$ is the return on a small-cap portfolio in excess of the return on a large-cap portfolio, $\lambda_{VALUE,t} = R_{VALUE,t} - R_{GROWTH,t}$ is the return on a value portfolio in excess of the return on a growth portfolio and $\upsilon_{GAS,t}$ is the mean-zero regression error, at time *t*. The intercept parameter α_{GAS}^{FF} is still interpreted as the risk premium error. The three beta parameters give the sensitivities to the market, size and value factors. Finally, the expression $\beta \times E(\lambda_{m,t}) + \beta_{SIZE} \times E(\lambda_{SIZE,t}) + \beta_{VALUE} \times E(\lambda_{VALUE,t})$ represents the risk premium from the Fama-French model.

The data for the market portfolio returns and the risk-free returns are the same used in the CAPM estimation. For the Canadian regressions, the small-cap portfolio returns are from a portfolio of all listed securities weighted equally whereas the large-cap portfolio returns are from a portfolio of all listed securities weighted by their market value.[11] The value and growth portfolios are determined from the earnings-to-price ratio. Specifically, the value (growth) portfolio contains firms having an earnings/price ratio in the highest (lowest) 30%.[12] For U.S. regressions, the size and value premiums are the Fama and French (1993, 1996a) SMB and HML variables, which are computed from market capitalization (size) and book-to-market ratio (value).[13] The annualized mean size and value risk premiums are respectively 8.9% and 6.4% for Canada from February 1985 to December 2006 and 2.7% and 6.0% for the U.S. from February 1973 to December 2006.

Table 3 presents the results of the estimates of the coefficients and the risk premium with the Fama-French model for the four gas distribution reference portfolios previously described. Panel A shows that the annualized risk premium errors are still positive for the four portfolios, ranging from 0.31% (for USindex) to 4.45% (for DJ_GasDi), but the underestimation is now statistically negligible. Panel D confirms that the inclusion of the value risk premium is instrumental in the reduction of the errors. The value betas are highly significant, with values between 0.30 and 0.71. The size betas (Panel C) are low and often not statistically different from zero, whereas the market betas (Panel B) are 0.54 on average. The estimated risk premiums vary between 4.23% and 8.83%.

INSERT TABLE 3 HERE.

Figure 2 compares the Fama-French and CAPM results. Figure 2a illustrates the risk premium errors of the two models, while Figure 2b shows their explanatory power given by the adjusted R^2. The

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[11] These indexes are taken from CFMRC for returns up to 2004 and then completed by the returns of the S&P/TSX Composite Index and the MSCI Barra Smallcap Index, respectively.

[12] Data come from the web site of Prof. French, who also provides specific instructions on the composition of the portfolios. The site gives returns for value and growth portfolios based on four indicators – earnings-to-price, book-to-market, cash flows-to-price and dividend-to-price. Fama and French (1996a) show that these indicators contain the same information about expected returns. Fama and French (1998) confirm the relevance of these indicators in explaining the returns in 12 major international financial markets and emerging financial markets. We chose the earnings-to-price indicator because it is more effective in capturing the premium of value securities compared to growth securities in Canada (see Bartholdy, 1993, and Bourgeois and Lussier, 1994). The indicator book-to-market is less effective in Canada because the value effect is mainly concentrated in more extreme portfolios (highest and lowest 10%) than in those available on the site (see L'Her, Masmoudi and Suret, 2002).

[13] Data again come from the web site of Prof. French. Detailed instructions on the composition of the SMB and HML variables are also provided.

errors have substantially fallen with the Fama-French model for all reference portfolios. Furthermore, the Fama-French model explains a much larger proportion of the variation in the reference portfolio returns.

INSERT FIGURE 2 HERE.

Figures 3 and 4 present the risk premium errors and the value betas, respectively, for the utilities that make up the CAindex portfolios (Figures 3a and 4a), the gas distributors in the USindex portfolios (Figures 3b and 4b) and the four utilities reference portfolios (Figures 3c and 4c). A comparison of Figure 3 with Figure 1 shows that the risk premium errors have decreased in all cases. None of the errors are now significantly different from zero. Figure 4 confirms that the reductions in the risk premium errors are caused by the inclusion of the value risk premium. All value betas are greater than 0.23 and statistically significant. For example, the TSX_Util portfolio has a value beta of 0.41 that contributes to reduce its risk premium error from 5.0% with the CAPM to 0.7% with the Fama-French model.

INSERT FIGURE 3 HERE.

INSERT FIGURE 4 HERE.

4.3. Discussion

Our results support the notion that the Fama-French model is better suited to estimate the risk premium for energy utilities than the CAPM, consistent with the findings of Schink and Bower (1994). They obtain higher costs of equity with the Fama-French model than with the CAPM and significant value betas, similar to the results for utilities reported by Schink and Bower (1994), Fama and French (1997) and Pastor and Stambaugh (1999). Arguably, the Fama-French model is also one of the most widely used models of expected stock returns in the academic finance literature (Davis, 2006).[14] Nevertheless, the model has not yet been adopted by regulatory bodies. One potential reason is that there is still a debate on the interpretation of the size and value premiums as rational or irrational factors.

On one side, starting with Fama and French (1993), the size and value factors are presented as part of a rational asset pricing model, where they reflect either state variables that predict investment

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[14] Another widely used model is the model of Carhart (1997), which adds a fourth factor to the Fama-French model to capture the momentum effect of Jegadeesh and Titman (1993). But since this effect is short-lived, the additional factor is irrelevant for estimates of the cost of equity capital.

opportunities following the theory of Merton (1973), or statistically useful variables to explain the returns following the theory of Ross (1976). On the other side, as first advocated by Lakonishok, Shleifer and Vishny (1994), the size and value factors are thought to be related to investors' irrationality in the sense that large-cap and growth stocks tend to be glamorized whereas small-cap and value stocks tend to be neglected. There is a vast literature on both sides of this debate.[15]

While the debate is important to improve our understanding of capital markets, Stein (1996) demonstrates that the theoretical interpretation of the model is not relevant to its application to determine the cost of capital. On one side, if the Fama-French model is rational, then the size and value factors capture true risks and should be accounted for in the risk premiums of energy utilities. On the other side, if the size and value factors are irrational, then the significant value betas of energy utilities indicate that they are neglected or undervalued firms. In this case, Stein (1996) shows that rational firms should not undertake a project that provides an expected return lower than the return estimated by the potentially irrational Fama-French model. They are better off in rejecting the project and simply buying back their own shares for which they expect an inflated future return because of the undervaluation. Thus, the potentially irrational Fama-French estimates serve as the appropriate hurdle rate for project investments. Hence, for both interpretations, the equity cost of capital of energy utilities generated by the Fama-French model is a useful guideline of the fair and reasonable rate of return for regulators. The next section looks at a second approach that goes beyond the CAPM to estimate the equity risk premium.

5. Equity Risk Premium with the Adjusted CAPM

This section considers two empirical adjustments to the CAPM estimates that have been proposed in the academic literature to account for their deficiencies. We call the CAPM with the addition of the two modifications the "Adjusted CAPM". Unlike the CAPM and the Fama-French model, the Adjusted CAPM is not an equilibrium model of expected returns. It contains adjustments to the CAPM that are empirically justified in a context where the known difficulties of a theoretical model need to be lessened for improved

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[15] A third interpretation, following Lo and MacKinlay (1990) and Kothari, Shanken and Sloan (1995), is that the results of the Fama-French model are spurious, due to in-sample biases like data snooping or survivorship. However, the fact that similar size and value premiums have been found in countries outside the U.S. has rendered this explanation less appealing.

estimation. We first introduce the Adjusted CAPM. Then we implement it to estimate the risk premium of energy utilities. We finally offer a brief discussion of our findings.

5.1. Model and Literature

The Adjusted CAPM is based on the CAPM but provides more realistic estimates of the rate of return by considering the empirical problems of the CAPM. More specifically, the Adjusted CAPM is a model in which the expected equity return of a gas utility is arrived at by

$$E(R_{GAS}) = R_f + \alpha_{GAS} \times (1 - \beta^{Adj}) + \beta^{Adj} \times \lambda_m .$$

Compare to the CAPM, this equation incorporates a modification to take into account that empirically estimated betas can be adjusted for better predictive power and a modification to take account of the fact the alpha (risk premium error) is high for low-beta value-oriented firms in the CAPM.

The first modification originates from the works of Blume (1971, 1975). Blume (1971) examines historical portfolio betas over two consecutive periods and finds that the historical betas, from one period to another, regress towards one, the average of the market. He also shows that the historical betas adjusted towards one predict future betas better than unadjusted betas. Blume (1975) builds a historical beta adjustment model to capture the tendency to regress towards one. He discovers that the best adjustment is to use a beta equal to $0.343 + 0.677 \times \beta^{His}$, a finding that led to the concept of "adjusted beta". Merrill Lynch, which popularized the use of adjusted betas based on Blume (1975)'s results, advocates the adjustment $\beta^{Adj} = 0.333 + 0.667 \times \beta^{His}$. Merrill Lynch's adjusted beta, now widely used in practice, represents a weighted-average between the beta of the market and the historical beta, with a two-thirds weighting on the historical beta.

The second adjustment is initially proposed by Litzenberger, Ramaswamy and Sosin (1980), who consider solutions to the problem that the CAPM gives a cost of equity capital with a downward bias for low beta firms, as discussed in section 3.1. They note that one way of remedying the problem is to add a bias correction to the CAPM risk premium. To be effective, the correction must take account of the importance of the risk premium error and the level of the firm's beta because these two elements influence the magnitude of the problem. To do this for low beta securities, Litzenberger, Ramaswamy and Sosin (1980) propose the bias correction $\alpha_{GAS} \times (1-\beta)$. As desired, the correction increases with the risk premium error of the CAPM, and decreases with the beta. The correction is nil for a firm for which the CAPM already works well (when $\alpha_{GAS} = 0$) or for a firm having a beta of one, two cases where the CAPM produces a fair rate of return on average. Morin (2006, Section 6.3) presents an application of this adjustment in regulatory finance through a model he calls the empirical CAPM.

In summary, the two modifications incorporated in the Adjusted CAPM involve first using the adjusted beta instead of the historical beta and second including the bias correction in the risk premium calculation. Considering the documented empirical usefulness of the two adjustments, the Adjusted CAPM has the potential to estimate a more reasonable risk premium for the energy utilities.

5.2. Risk Premium Estimates

To compute the Adjusted CAPM estimates for our sample of utilities, the starting point is the estimates of the CAPM of Section 3.2, given in Table 2. The beta estimates are now understood as the unadjusted historical betas β^{His}. The gas utility risk premium with the Adjusted CAPM can then be expressed as $\alpha_{GAS} \times \left(1-\beta^{Adj}\right) + \beta^{Adj} \times E\left(\lambda_{m,t}\right)$, where $\beta^{Adj} = 0.333 + 0.667 \times \beta^{His}$. The risk premium error on the Adjusted CAPM is arrived at by $\alpha_{GAS}^{Adj} = E\left(R_{GAS,t} - R_{f,t}\right) - \left[\alpha_{GAS} \times \left(1-\beta^{Adj}\right) + \beta^{Adj} \times E\left(\lambda_{m,t}\right)\right]$.

Table 4 shows the Adjusted CAPM estimates using the four gas distribution reference portfolios. The estimates of the risk premium error α_{GAS}^{Adj}, the adjusted beta β^{Adj}, the bias correction $\alpha_{GAS} \times \left(1-\beta^{Adj}\right)$ and the risk premium are shown in Panels A, B, C and D, respectively. The risk premium errors are still positive for the four portfolios, with values ranging from 1.39% (for CAindex) to 2.89% (for USindex), but the underestimation is only significant for a single portfolio (for USindex). The reduction in errors comes from the use of adjusted betas, which are 0.56 on average, and the bias corrections, which are 2.96% on average. Lastly, the risk premiums vary between 4.88% and 8.27%, findings that are comparable to the estimates obtained with the Fama-French model.

INSERT TABLE 4 HERE.

Figure 5 shows the risk premium errors for the utilities that make up the CAindex portfolios (Figure 5a), the gas distributors in the USindex portfolios (Figure 5b) and the four utilities reference portfolios (Figure 5c). The errors are generally insignificant and a comparison with Figure 1 indicates that they have decreased considerably for all portfolios. For example, for the TSX_Util portfolio, the error is down from 5.0% with the CAPM to 0.9% with the Adjusted CAPM.

INSERT FIGURE 5 HERE.

5.3. Discussion

Our results support the validity of the Adjusted CAPM as a useful model for determining the rate of return on energy utilities. While its risk premium estimates are in the same range as the Fama-French estimates, it arrives at its results from a different perspective. The Fama-French model advocates the use of additional risk factors to reduce the CAPM risk premium errors. The Adjusted CAPM, through its bias correction, effectively estimates the risk premium as a weighted-average of the CAPM risk premium and the realized historical risk premium, with a weighting of beta on the former.

The Adjusted CAPM thus recognizes that the CAPM is an imperfect model that can be improved with the information contained in the historical returns. Pastor and Stambaugh (1999) proposes a similar strategy by demonstrating how to estimate the cost of equity by using Bayesian econometrics to incorporate the CAPM risk premium error (or alpha) in an optimal manner based on the priors of the evaluator. Consistent with our results with the Adjusted CAPM, they also show evidence of higher costs of equity for energy utilities using their technique than using the CAPM alone.[16] As the Adjusted CAPM does not require additional risk factors like size and value, the model might be easier to interpret for regulators already familiar with the standard CAPM in their decisions.

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[16] Pastor and Stambaugh (1999) obtain risk premiums that vary between the CAPM estimates, when they assume that there is zero prior uncertainty on the CAPM, and the historical estimates, when they assume that there is infinite prior uncertainty on the CAPM. Our bias correction corresponds approximately to a prior uncertainty on the CAPM between 3% and 6% in their setup.

6. Conclusion

It is difficult to overstate the importance of the evaluation of the expected rate of return in finance. For a firm's management group, the expected rate of return on equity (or the equity cost of capital) is central to its overall cost of capital, i.e. the rate used to determine which projects will be undertaken. For portfolio managers, the expected rate of return on equity is an essential ingredient in portfolio decisions. For regulatory bodies, the expected return on equity is the basis for determining the fair and reasonable rate of return of a regulated enterprise. This paper is interested in evaluating the rate of return in the context of regulated energy utilities.

The academic literature contains numerous theories for determining the expected rate of return on equity. As those theories are based on simplified assumptions of the complex world in which we live, they cannot be perfect. Even if the theoretical merit of the different models can be debated, the determination of the most valid approach to explain the financial markets really becomes an empirical question – it is necessary to answer the question "which theory best explains the information about actual returns?" This paper empirically examines the validity of the model the most often used in the rate adjustment formula of regulatory bodies, the CAPM, one of the most prominent academic alternatives, the Fama-French model, and a version of the CAPM modified to account for some of its empirical deficiencies, the Adjusted CAPM.

Our empirical results show that the risk premiums for energy utilities estimated with the CAPM are rejected as too low compare to the historical risk premiums. The rejections are related to the well-documented CAPM underestimation of the average returns of low-beta firms and value firms. The Fama-French model and the Adjusted CAPM appear better specified, as we cannot reject the hypothesis that their risk premium errors are equal to zero. They suggest equity risk premiums for gas distribution utilities between 4% and 8%. Overall, our findings demonstrate that models that go beyond the CAPM have the potential to improve the estimation of the cost of equity capital of energy utilities. They are thus interesting avenues for regulators looking to set fair and reasonable equity rates of return.

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TABLE 1: Descriptive Statistics of Monthly Returns

Variable	N	Mean	St Dev	Min	Max	Brief Description
Panel A: Canadian Energy Utilities						
ATCO	263	0.013	0.067	-0.301	0.279	ATCO Ltd.
Algonqui	108	0.009	0.054	-0.163	0.166	Algonquin Power Income Fund
CanUtili	263	0.012	0.043	-0.107	0.159	Canadian Utilities Limited
EPCOR	114	0.008	0.046	-0.201	0.108	EPCOR Power
Emera	143	0.009	0.043	-0.137	0.115	Emera Incorporated
Enbridge	263	0.011	0.054	-0.365	0.205	Enbridge Inc.
FortChic	107	0.009	0.054	-0.119	0.210	Fort Chicago Energy Partners
Fortis	228	0.013	0.041	-0.134	0.146	Fortis Inc.
GazMetro	166	0.010	0.037	-0.134	0.084	Gaz Métro Limited Partnerships
NorthPow	104	0.011	0.063	-0.202	0.205	Northland Power Income Fund
PacNorth	263	0.010	0.070	-0.400	0.507	Pacific Northern Gas
TransAlt	263	0.009	0.048	-0.217	0.188	TransAlta Corporation
TransCan	258	0.008	0.054	-0.214	0.254	TransCanada Pipelines
CAindex	263	0.010	0.031	-0.130	0.087	Equally-weighted portfolio
Panel B: U.S. Gas Distribution Utilities						
AGL_Res	407	0.013	0.052	-0.138	0.253	AGL Resources Inc.
Atmos	277	0.013	0.063	-0.302	0.269	Atmos Energy Corp.
Laclede	407	0.012	0.056	-0.148	0.374	Laclede Group
NJ_Res	407	0.013	0.063	-0.171	0.577	New Jersey Resources Corp.
Northwes	407	0.012	0.060	-0.236	0.274	Northwest Natural Gas Co.
Piedmont	407	0.013	0.059	-0.188	0.315	Piedmont Natural Gas Co.
SouthJer	407	0.012	0.058	-0.194	0.486	South Jersey Industries
Southwes	407	0.011	0.070	-0.304	0.234	Southwest Gas Corp.
WGL_Hold	407	0.012	0.071	-0.232	0.807	WGL Holdings Inc.
USindex	407	0.012	0.041	-0.121	0.338	Equally-weighted portfolio
Panel C: Sector Indexes						
TSX_Util	228	0.010	0.037	-0.101	0.114	S&P/TSX Utilities Index
DJ_GasDi	180	0.012	0.043	-0.139	0.137	Dow Jones Canada Gas Distribution Index
DJ_Util	180	0.007	0.036	-0.139	0.101	Dow Jones Canada Utilities Index
DJ_GasUS	180	0.012	0.039	-0.120	0.143	Dow Jones US Gas Distribution Index
DJ_UtiUS	180	0.009	0.042	-0.127	0.136	Dow Jones US Utilities Index
FF_Util	407	0.010	0.041	-0.123	0.188	Fama-French US Utilities Index

NOTES: This table presents descriptive statistics on the monthly returns of 13 Canadian utilities and their equally-weighted portfolio (CAindex) in Panel A, of nine U.S. gas distribution utilities and their equally-weighted portfolio (USindex) in Panel B, and on selected utilities sector indexes in Panel C. The columns labelled N, Mean, St Dev, Min and Max correspond respectively to the number of observations, the mean, the standard deviation, the minimum value and the maximum value. The column labelled Brief Description gives the full name of the utility holding companies or the utilities sector indexes.

TABLE 2: CAPM Risk Premium Estimates for the Gas Distribution Reference Portfolios

Portfolio	Estimate	SE	t-stat	Prob > |t|
Panel A: Risk Premium Error (Alpha)				
DJ_GasDi	8.43	3.79	2.22	0.028
CAindex	4.52	2.33	1.94	0.053
DJ_GasUS	7.39	3.34	2.21	0.028
USindex	6.23	1.95	3.19	0.002
Panel B: Beta				
DJ_GasDi	0.21	0.11	1.95	0.053
CAindex	0.34	0.07	4.60	<.0001
DJ_GasUS	0.37	0.09	4.16	<.0001
USindex	0.46	0.06	7.37	<.0001
Panel C: Risk Premium				
DJ_GasDi	1.66	1.28	1.30	0.195
CAindex	1.76	1.11	1.58	0.116
DJ_GasUS	2.74	1.46	1.87	0.063
USindex	2.72	1.33	2.04	0.042

NOTES: This table reports the results of the estimation of the CAPM for the gas distribution reference portfolios. Panels A to C look at the annualized risk premium error or alpha (in percent), the market beta and the annualized risk premium (in percent), respectively. The columns labelled Estimate, SE, t-stat and Prob > |t| give respectively the estimates, their standard errors, their t-statistics and their p-values.

TABLE 3: Fama-French Risk Premium Estimates for the Gas Distribution Reference Portfolios

Portfolio	Estimate	SE	t-stat	Prob > |t|
Panel A: Risk Premium Error (Alpha)				
DJ_GasDi	4.45	3.11	1.43	0.155
CAindex	2.04	1.85	1.11	0.270
DJ_GasUS	1.31	3.01	0.43	0.665
USindex	0.31	1.80	0.17	0.863
Panel B: Beta				
DJ_GasDi	0.41	0.08	5.06	<.0001
CAindex	0.48	0.05	10.38	<.0001
DJ_GasUS	0.63	0.07	9.64	<.0001
USindex	0.64	0.06	11.18	<.0001
Panel C: Size Beta				
DJ_GasDi	-0.01	0.08	-0.11	0.912
CAindex	-0.02	0.05	-0.51	0.613
DJ_GasUS	0.00	0.09	0.04	0.971
USindex	0.20	0.07	2.9	0.004
Panel D: Value Beta				
DJ_GasDi	0.33	0.06	5.12	<.0001
CAindex	0.30	0.04	7.64	<.0001
DJ_GasUS	0.59	0.13	4.41	<.0001
USindex	0.71	0.10	7.21	<.0001
Panel E: Risk Premium				
DJ_GasDi	5.64	1.78	3.17	0.002
CAindex	4.23	1.52	2.78	0.006
DJ_GasUS	8.83	2.32	3.81	0.000
USindex	8.64	2.16	4	<.0001

NOTES: This table reports the results of the estimation of the Fama-French model for the gas distribution reference portfolios. Panels A to E look at the annualized risk premium error or alpha (in percent), the market beta, the size beta, the value beta and the annualized risk premium (in percent), respectively. The columns labelled Estimate, SE, t-stat and Prob > |t| give respectively the estimates, their standard errors, their t-statistics and their p-values.

TABLE 4: Adjusted CAPM Risk Premium Estimates for the Gas Distribution Reference Portfolios

Portfolio	Estimate	SE	t-stat	Prob > |t|
Panel A: Risk Premium Error (Alpha)				
DJ_GasDi	1.82	2.00	0.91	0.365
CAindex	1.39	1.54	0.9	0.366
DJ_GasUS	2.68	1.97	1.36	0.176
USindex	2.89	1.37	2.11	0.035
Panel B: Adjusted Beta				
DJ_GasDi	0.47	0.07	6.69	<.0001
CAindex	0.56	0.05	11.38	<.0001
DJ_GasUS	0.58	0.06	9.84	<.0001
USindex	0.64	0.04	15.44	<.0001
Panel C: Bias Correction				
DJ_GasDi	4.46	2.28	1.96	0.052
CAindex	1.99	1.10	1.81	0.071
DJ_GasUS	3.12	1.61	1.94	0.054
USindex	2.26	0.77	2.94	0.004
Panel D: Risk Premium				
DJ_GasDi	8.27	2.71	3.05	0.003
CAindex	4.88	2.11	2.31	0.021
DJ_GasUS	7.45	2.52	2.96	0.004
USindex	6.05	1.89	3.21	0.002

NOTES: This table reports the results of the estimation of the Adjusted CAPM for the gas distribution reference portfolios. Panels A to D look at the annualized risk premium error or alpha (in percent), the adjusted market beta, the bias correction and the annualized risk premium (in percent), respectively. The columns labelled Estimate, SE, t-stat and Prob > |t| give respectively the estimates, their standard errors, their t-statistics and their p-values.

FIGURE 1: Risk Premium Errors with the CAPM for Various Utilities

Figure 1a: Firms in the CAindex Portfolio

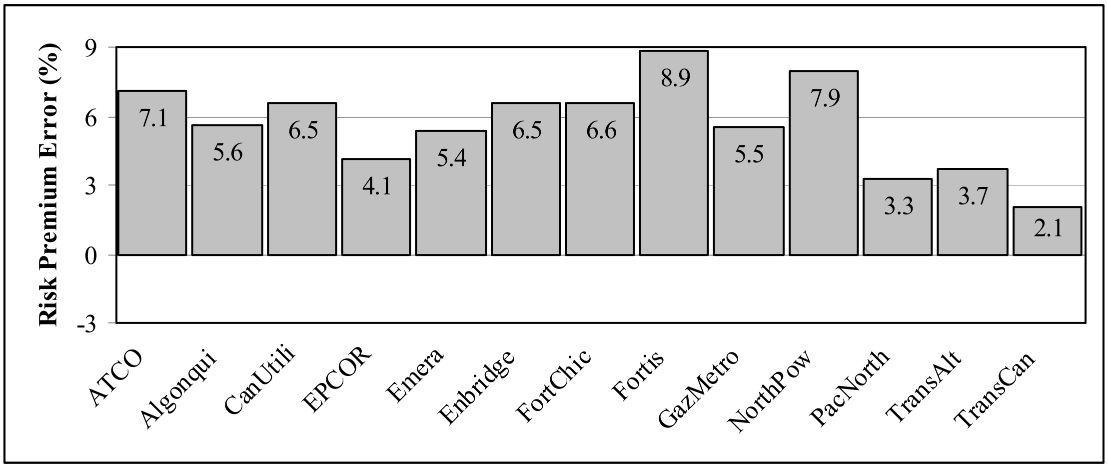


Figure 1b: Firms in the USindex Portfolio

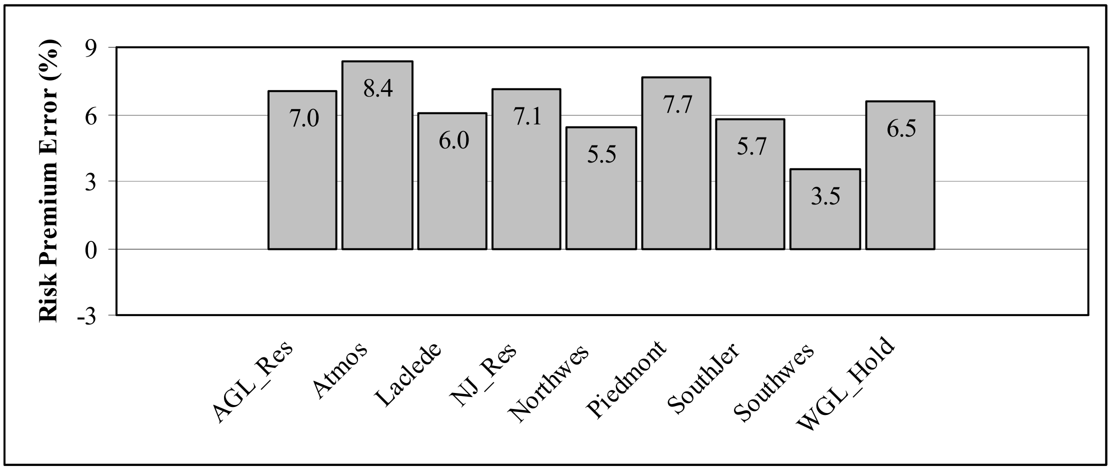
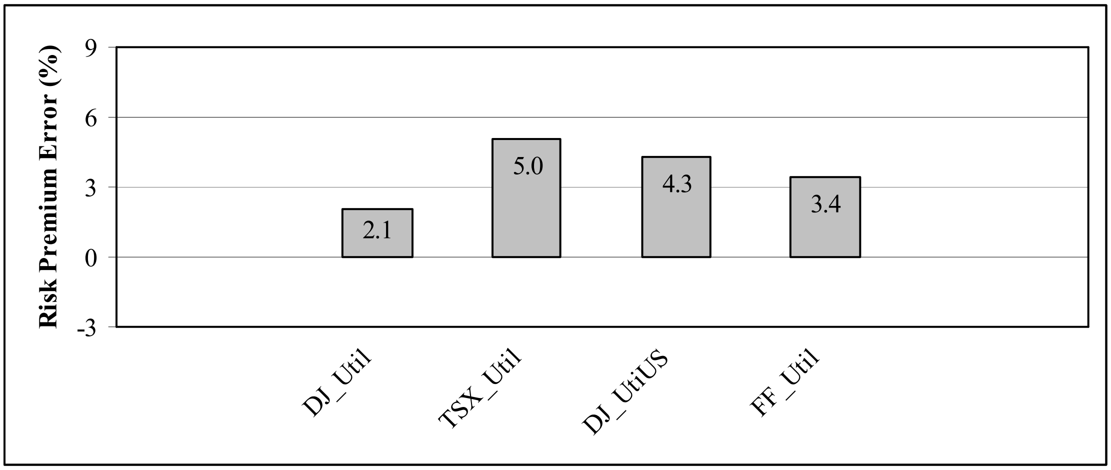


Figure 1c: Utilities Reference Portfolios



NOTES: This figure shows the annualized risk premium errors (or alphas) with the CAPM for the Canadian utilities in the CAindex portfolio (Figure 1a), the U.S. gas distributors in the USindex portfolio (Figure 1b) and the utilities reference portfolios (Figure 1c).

FIGURE 2: Comparison of the Fama-French and CAPM Results

Figure 2a: Risk Premium Errors

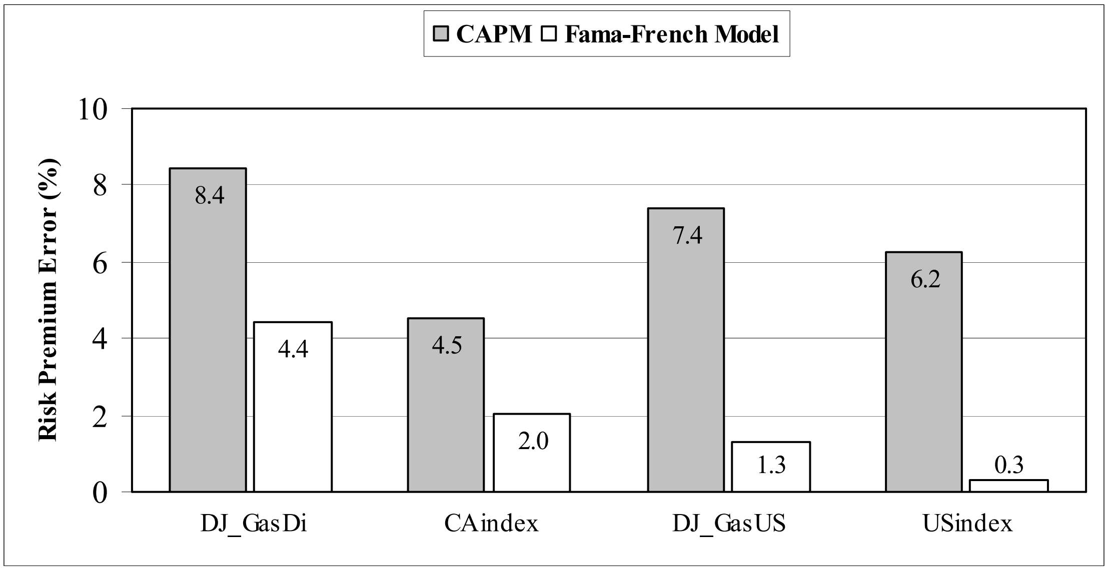
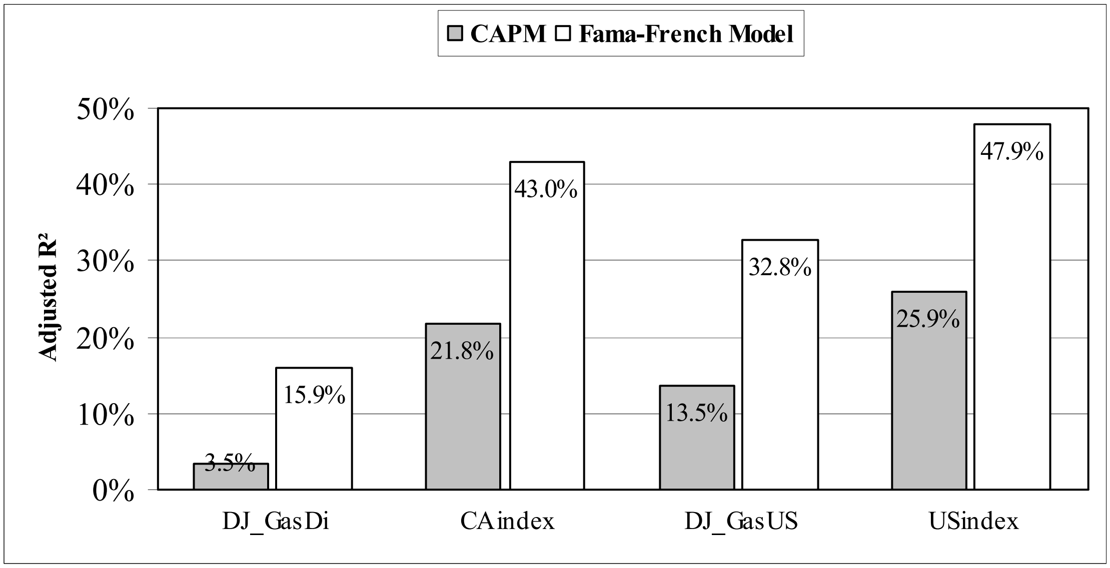


Figure 2b: Adjusted R²s



NOTES: This figure compares the results of the CAPM (gray bars) and the Fama-French model (white bars) in terms of annualized risk premium errors (or alphas) (Figure 2a) and adjusted R² (Figure 2b) for the gas distribution reference portfolios.

FIGURE 3: Risk Premium Errors with the Fama-French Model for Various Utilities

Figure 3a: Firms in the CAindex Portfolio

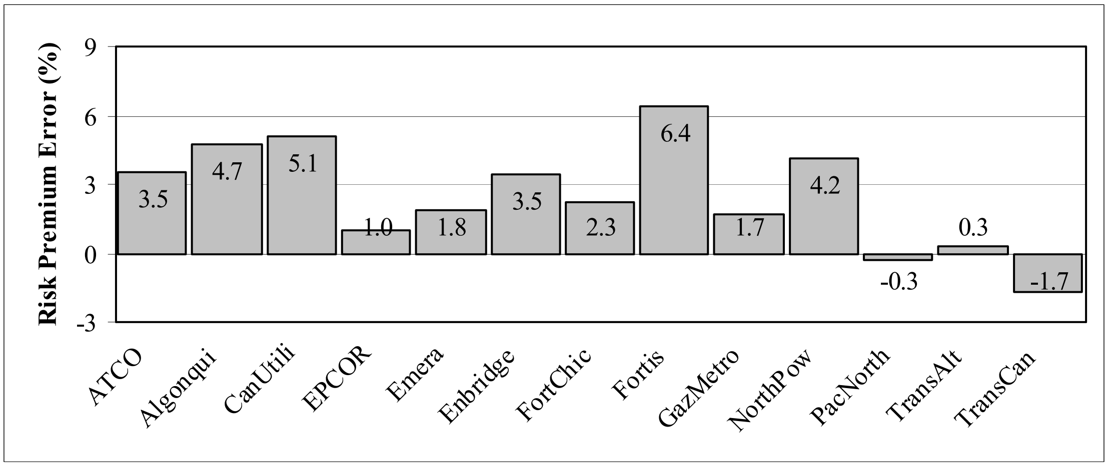


Figure 3b: Firms in the USindex Portfolio

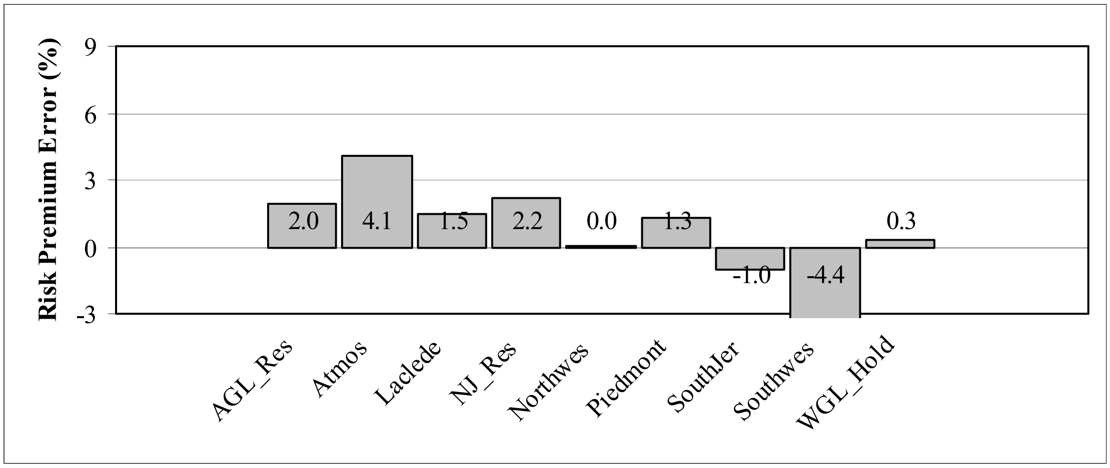
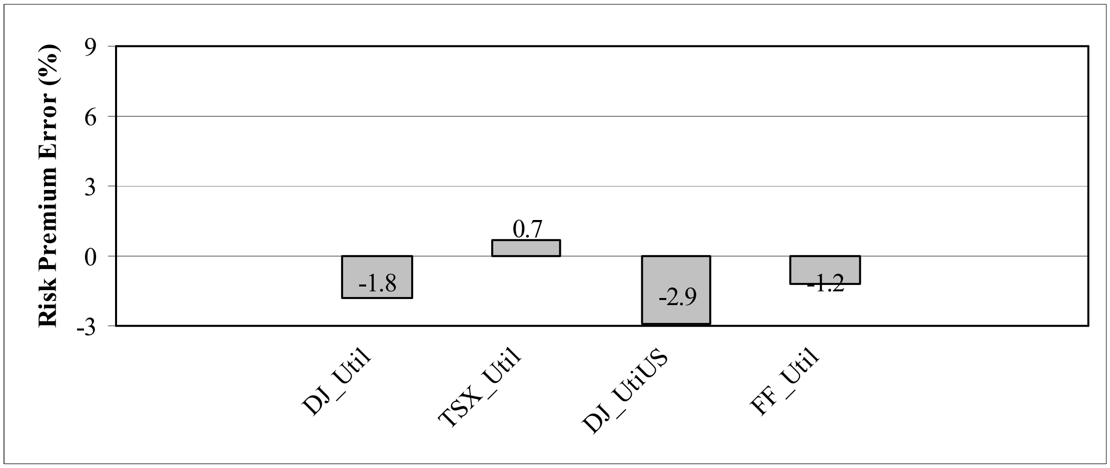


Figure 3c: Utilities Reference Portfolios



NOTES: This figure shows the annualized risk premium errors (or alphas) with the Fama-French model for the Canadian utilities in the CAindex portfolio (Figure 3a), the U.S. gas distributors in the USindex portfolio (Figure 3b) and the utilities reference portfolios (Figure 3c).

FIGURE 4: Value Betas for Various Utilities

Figure 4a: Firms in the CAindex Portfolio

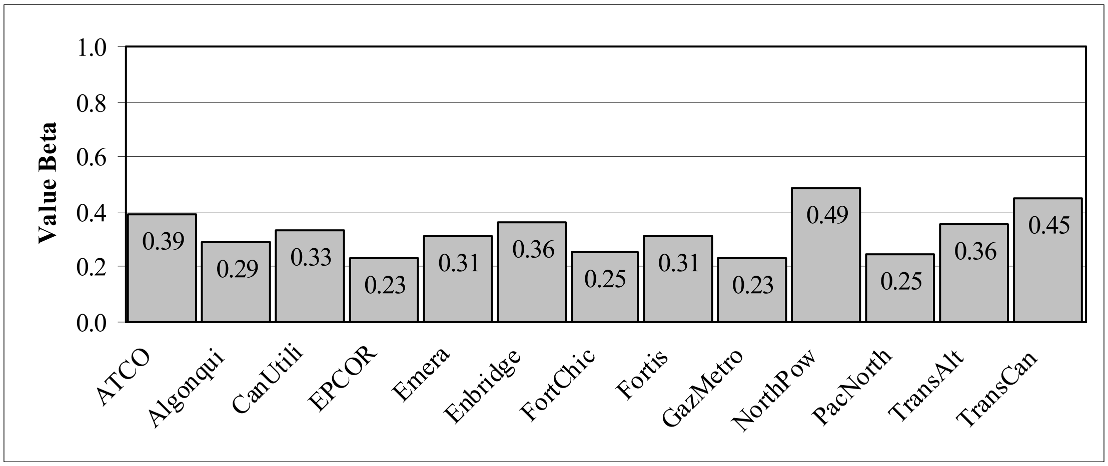


Figure 4b: Firms in the USindex Portfolio

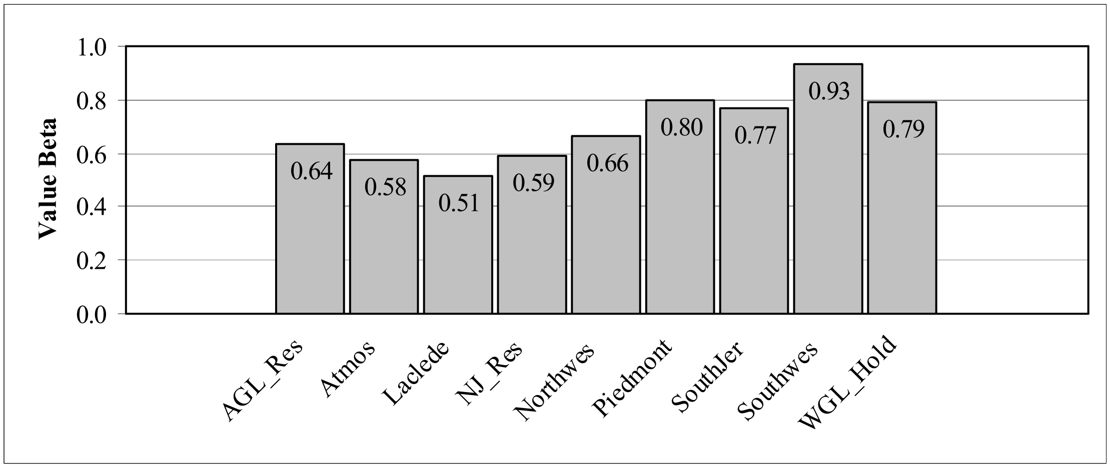
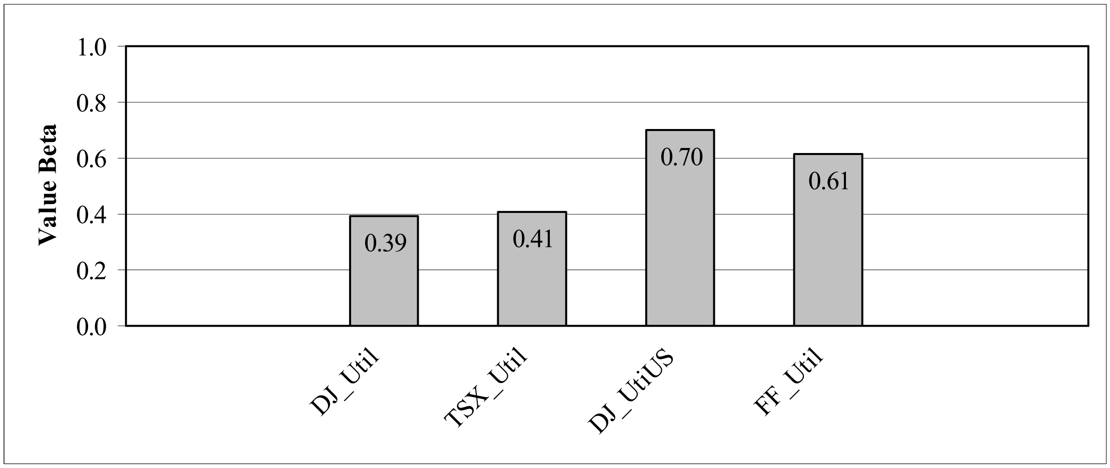


Figure 4c: Utilities Reference Portfolios



NOTES: This figure shows the value betas in the Fama-French model for the Canadian utilities in the CAindex portfolio (Figure 4a), the U.S. gas distributors in the USindex portfolio (Figure 4b) and the utilities reference portfolios (Figure 4c).

FIGURE 5: Risk Premium Errors with the Adjusted CAPM for Various Utilities

Figure 5a: Firms in the CAindex Portfolio

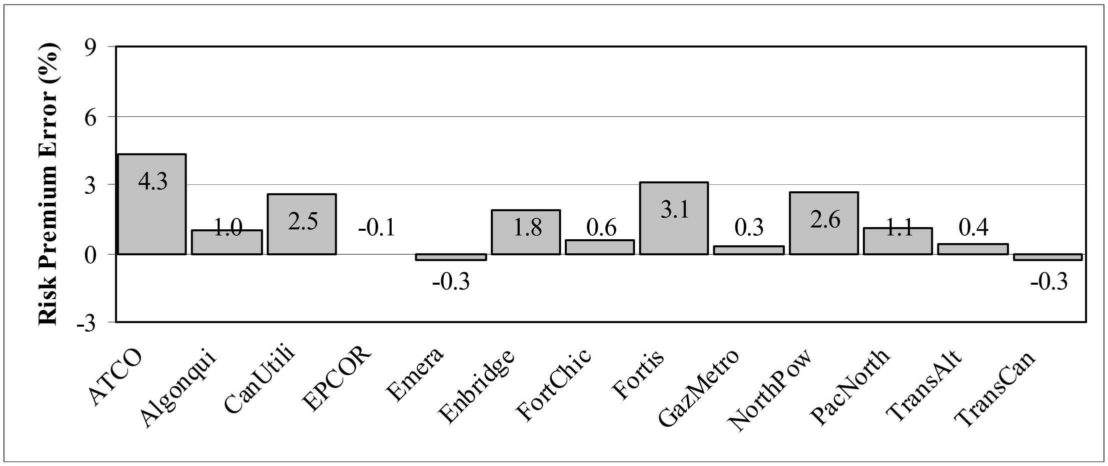


Figure 5b: Firms in the USindex Portfolio

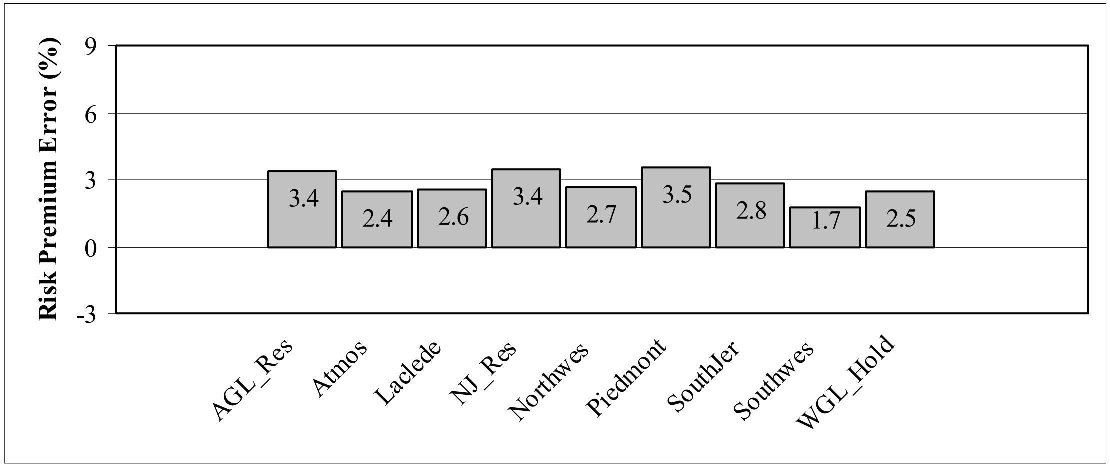
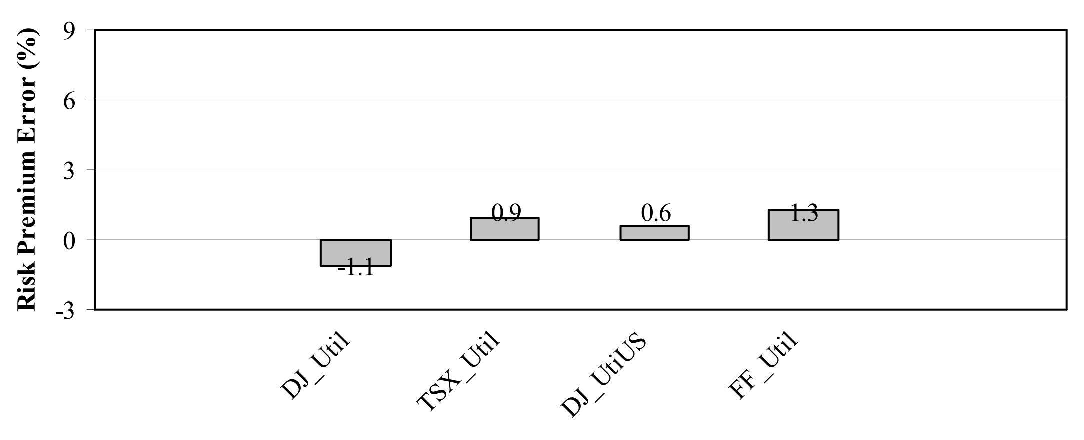


Figure 5c: Utilities Reference Portfolios



NOTES: This figure shows the annualized risk premium errors (or alphas) with the Adjusted CAPM for the Canadian utilities in the CAindex portfolio (Figure 5a), the U.S. gas distributors in the USindex portfolio (Figure 5b) and the utilities reference portfolios (Figure 5c).

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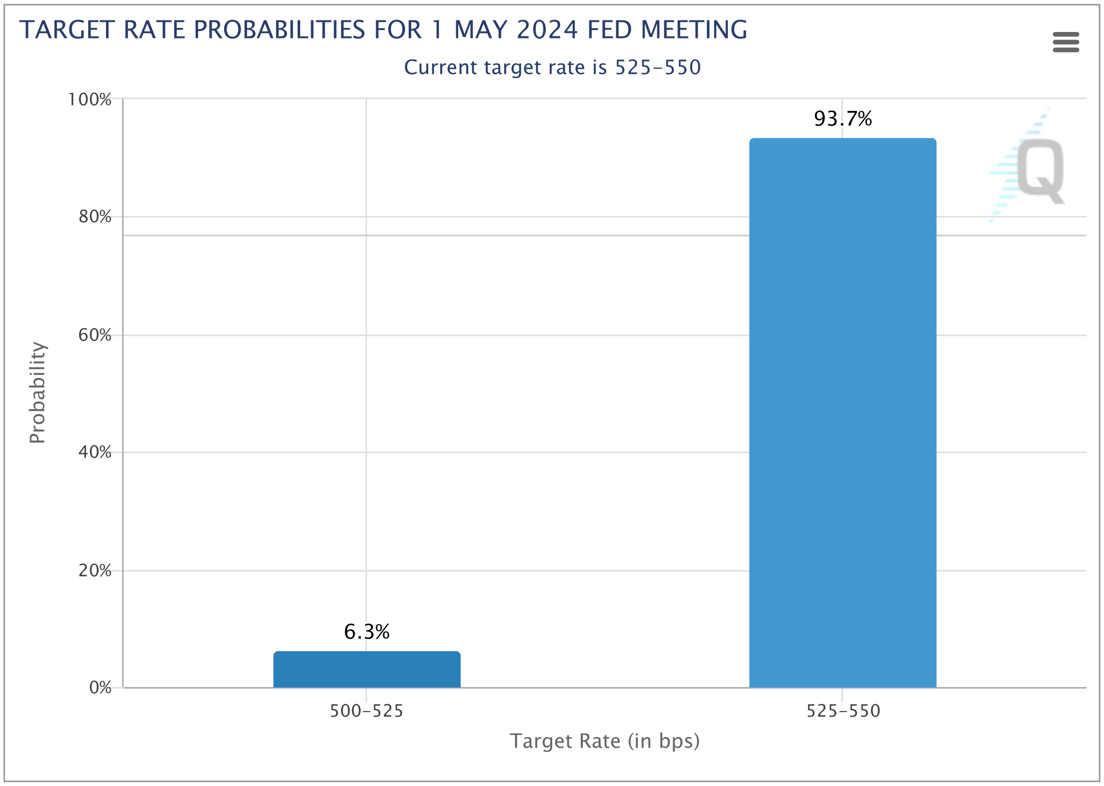
1 May24 | 12 Jun24 | 31 Jul24 | 18 Sep24 | 7 Nov24 | 18 Dec24 | 29 Jan25 | 19 Mar25 | 30 Apr25 | 18 Jun25 | 30 Jul25 | 24 Sep25

MEETING INFORMATION					
MEETING DATE	CONTRACT	EXPIRES	MID PRICE	PRIOR VOLUME	PRIOR OI
1 May 2024	ZQK4	31 May 2024	94.6975	24,813	511,551

PROBABILITIES		
EASE	NO CHANGE	HIKE
6.3 %	93.7 %	0.0 %


TARGET RATE PROBABILITIES FOR 1 MAY 2024 FED MEETING

Current target rate is 525-550

TARGET RATE (BPS)	PROBABILITY(%)			
	NOW *	1 DAY 27 MAR 2024	1 WEEK 21 MAR 2024	1 MONTH 28 FEB 2024
475-500	0.0%	0.0%	0.0%	0.6%
500-525	6.3%	9.6%	11.7%	18.1%
525-550 (Current)	93.7%	90.4%	88.3%	81.3%

* Data as of 28 Mar 2024 10:07:17 CT

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ECONOMY

The U.S. economy grew at blistering 3.3% pace in Q4 while inflation pulled back

PUBLISHED THU, JAN 25 2024•8:30 AM EST | UPDATED THU, JAN 25 2024•10:21 AM EST

Jeff Cox
@JEFF.COX.7528
@JEFFCOXCNBCCOM

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KEY POINTS

- GDP, a measure of all the goods and services produced, increased at a 3.3% annualized rate in the fourth quarter of 2023. Wall Street had been looking for a 2% gain.

- The U.S. economy for all of 2023 accelerated at a 2.5% annualized pace, well ahead of the Wall Street outlook at the beginning of the year for few if any gains and better than the 1.9% increase in 2022.

There also was progress on inflation. Core prices for personal consumption expenditures rose 2% for the period, while the headline rate was 1.7%.

FAIR VALUE

	FUTURE CHG	FAIR VALUE	IMPLIED OPEN
S&P 500	+9.25	-0.45	+9.70
DJIA	+18.00	-5.61	+23.61

VIDEO 03:45

The U.S. economy grew at a 3.3% pace in the fourth quarter, much better than expected

forecasters had thought was inevitable, the Commerce Department reported Thursday.

Gross domestic product, a measure of all the goods and services produced, increased at a 3.3% annualized rate in the fourth quarter of 2023, according to data adjusted seasonally and for inflation.

That compared with the Wall Street consensus estimate for a gain of 2% in the final three months of the year. The third quarter grew at a 4.9% pace.

In addition to the better than expected GDP move, there also was some progress on inflation.

Core prices for personal consumption expenditures, which the Federal Reserve prefers as a longer-term inflation measure, rose 2% for the period, while the headline rate was 1.7%.

On an annual basis, the PCE price index rose 2.7%, down from 5.9% a year ago, while the core figure excluding food and energy posted a 3.2% increase annually, compared with 5.1%.

a lot of recreation spending as well as taking trips. We've been expecting a soft landing for some time. This is just one step in that direction."

The U.S. economy for all of 2023 accelerated at a 2.5% annualized pace, well ahead of the Wall Street outlook at the beginning of the year for few if any gains and better than the 1.9% increase in 2022.

As had been the case through the year, a strong pace of consumer spending helped drive the expansion. Personal consumption expenditures increased 2.8% for the quarter, down just slightly from the previous period.

State and local government spending also contributed, up 3.7%, as did a 2.5% increase in federal government expenditures. Gross private domestic investment rose 2.1%, another significant factor for the robust quarter.

The chain-weighted price index, which accounts for prices as well as changes in consumer behavior, increased 1.5% for the quarter, down sharply from 3.3% in the previous period and below the Wall Street estimate for a 2.5% acceleration.

"This year has been like Rock 'Em Sock 'Em Robots, and the economy is knocking the blocks off the economists, always outperforming," said Dan North, senior economist with Allianz Trade Americas. Fed Chair Jerome Powell "has got to have

Markets showed only a modest reaction to the report. Stock futures gained slightly while Treasury yields moved lower. Futures markets continued to reflect the likelihood that the Fed will enact its first rate cut in May, though the CME Group's FedWatch gauge put the odds of a March cut at 47.4% around 10 a.m. ET.

"It was a great report, but you didn't see the market move much because GDP is backward-looking. It told us what happened in October and November and December," North said. "It's great for historical patterns, but it doesn't really tell us much about where we're headed."

In other economic news Thursday, initial jobless claims totaled 214,000, an increase of 25,000 from the previous week and ahead of the estimate for 199,000, according to the Labor Department. Continuing claims rose to 1.833 million, an increase of 27,000.

The GDP report wraps up a year in which most economists were almost certain the U.S. would enter at least a shallow recession. Even the Fed had predicted a mild contraction due to banking industry stress last March.

However, a resilient consumer and a powerful labor market helped propel the economy through the year, which also featured an ongoing pullback in manufacturing and a Fed that kept raising interest rates in its battle to bring down inflation.

Concerns remain, however, that the economy faces more challenges ahead.

Some of the worries center around the lagged effects of monetary policy, specifically the 11 interest rate hikes totaling 5.25 percentage points that the Fed approved between March 2022 and July 2023. Conventional economic wisdom is that it can take as long as two years for such policy tightening to make its way through the system, so that could contribute to slowness ahead.

Other angst centers around how long consumers can keep spending as savings dwindle and high-interest debt loads accrue. Finally, there's the nature of what is driving the boom beyond the consumer: Government deficit spending has been a significant contributor to growth, with the total federal IOU at $34 trillion and counting. The budget deficit has totaled more than half a trillion dollars for the first three months of fiscal 2024.

There also are political worries as the U.S. enters the heart of the presidential election campaign, and geopolitical fears with violence in the Middle East and the continuing bloody Ukraine war.

Correction: The price index for personal consumption expenditures rose 2.7% on an annual basis, down from 5.9% a year ago. An earlier version mischaracterized the figures.

- *The early winner in the bitcoin ETF race has raked in $1 billion*
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FitchRatings

RATING ACTION COMMENTARY

Fitch Affirms MDU and Subs.; Centennial's Outlook to Positive and Cascade's Outlook to Negative

Thu 03 Aug, 2023 - 2:42 PM ET

Fitch Ratings - Chicago - 03 Aug 2023: Fitch Ratings has affirmed the Long-Term Issuer Default Rating (IDR) of MDU Resources Group, Inc.'s (MDU) and those of its regulated utility subsidiaries, Montana-Dakota Utilities Co. and Cascade Natural Gas Corporation at 'BBB+'. The Rating Outlooks for MDU and Montana-Dakota are Stable while Cascade's Outlook has been revised to Negative from Stable. Fitch has also affirmed the IDR of Centennial Energy Holdings, Inc. (Centennial), the holding company for MDU's non-utility operations, at 'BBB' and revised its Outlook to Positive from Stable. Finally, Fitch has also affirmed MDU's and subsidiaries ST-ratings at F2.

Fitch believes MDU Resources Group, Inc.'s (MDU) plan to become a fully regulated energy delivery company by spinning off its remaining non-regulated business, Construction Services Group (CSG), is supportive of MDU's current Long-Term IDR at 'BBB+' and would likely result in a one-notch upgrade of the Long-Term IDR of Centennial Energy Holdings, Inc. to 'BBB+' following the completion of the transaction.

The rating affirmation at MDU reflects expectations of an improved business risk profile comprised of nearly 100% regulated operations following the transaction and weak but sufficient credit measures for its rating level. The Positive Outlook at Centennial reflects an improving business risk profile focused on its FERC regulated pipeline business and expectations for leverage measures to remain strong due to management's pro-active efforts to strengthen the balance sheet.

The Negative Outlook at Cascade reflects increasing financial pressure on leverage metrics due to a large capex program amid a challenging regulatory environment. A lack of improvement in leverage towards the 5.0x level over the rating horizon would likely result in a one-notch rating downgrade. Fitch expects the spin-off of CSG to close in the 2nd half of 2024 and will resolve Centennial's Positive Outlook at that time.

KEY RATING DRIVERS

MDU

Improving Business Risk Profile: MDU's ratings reflect an improving business risk profile focused on regulated utility operations following the expected spin-off of CSG in 2024 with the proportion of EBITDA derived from regulated operations improving to nearly 100% from 45% in 2022. CSG currently accounts for 31% of consolidated EBITDA.

Utilities Anchor Credit Profile: MDU owns four low-risk regulated electric and natural gas utilities that operate in balanced regulatory compacts and serve parts of eight contiguous states from Minnesota to Washington, providing regulatory diversity. Post-spin of CSG in 2024, Fitch expects utility operations to contribute approximately 80% of ongoing EBITDA with the remainder provided by the FERC regulated pipeline business.

Relatively Balanced Regulation: Regulatory mechanisms are generally supportive of credit quality. Some regulatory jurisdictions allow the use of decoupling and riders for investments in renewables, gas pipe replacement, transmission and environmental equipment. All jurisdictions allow trackers for fuel and purchased power costs, and a purchased gas adjustment clause for gas utilities. North Dakota and Montana were the largest contributors to electric revenue while Idaho and Washington were the largest contributors to natural gas revenue.

Conservative Financing Policy: Fitch recognizes MDU's continued commitment to manage its businesses' balance sheet conservatively. Centennial's financial profile benefits from relatively modest financial leverage, with debt/total capitalization managed at around 35%-40%. Utilities' financial policies are managed consistent with their authorized regulatory capital structures.

Adequate Leverage: Post-Spin MDU's pro forma funds from operations (FFO) leverage are projected to weaken and average 5.0x in 2025- 2026 from approximately 3.8x in 2022, above previous pre-spin projections of an average of 3.1x and at Fitch's negative FFO leverage sensitivity threshold of 5.0x. There remains no headroom for further deterioration in leverage measures at the current rating level. Fitch believes MDU's improved business risk profile that is focused on utility operations is an offset to the negative financial impacts of the separation of its construction businesses.

Parent-Subsidiary Linkage: There is parent subsidiary relationship between MDU and all of its rated subsidiaries. Fitch determines MDU's standalone credit profile (SCP) based upon consolidated metrics. MDU's consolidated profile and its regulated utility subsidiaries, Montana-Dakota and Cascade, are all rated 'BBB+'. Fitch would limit the difference between MDU and any of its regulated subsidiaries to two notches if Fitch were to determine the subsidiaries' SCPs to be stronger than MDU's. The assessment would be based upon Fitch's porous assessment for legal ring fencing and access and control.

Fitch follows a stronger parent/weaker subsidiary path for Centennial, which houses MDU's non-utility operations. Fitch considers Centennial's legal, strategic and operational incentives as weak, which leads itself to a standalone credit profile.

Montana-Dakota Utilities Co.

Low-Risk Business Profile: Montana-Dakota's credit profile reflects the relatively low-risk nature of its integrated electric and gas businesses that operate in North Dakota, South Dakota, Montana and Wyoming. The multi-state operations provide earnings and regulatory diversity that is supportive of credit quality. The utility has limited exposure to commodity prices. Fitch calculates electric operations represented approximately 73% of total EBITDA in 2022. North Dakota and Montana were the largest contributors, approximating 65% and 21% of total revenue, respectively.

Generally Supportive Regulation: The utility benefits from favorable rate mechanisms in North Dakota that feature riders for transmission and environmental/renewables investments, forward-looking test year, interim rate relief and a fuel adjustment clause. In Montana, the utility can recover property tax expenses via a property tax tracker. A weather normalization clause in both North Dakota and South Dakota adds partial cash flow stability to natural gas operations. Montana-Dakota has generally done well in rate cases in each of its regulatory jurisdictions, in Fitch's view.

GRC Updates in Montana and North Dakota: Fitch anticipates a reasonable outcome in Montana-Dakota's pending GRC in Montana and views the outcome of its recent GRC in North Dakota in June 2023 as supportive of credit quality. In Montana the company entered into a settlement agreement with key intervenors in its general rate case in June subject to regulatory approval. The settlement agreement requests a rate increase of $6.1 million based on a 9.65% ROE and an equity layer of 50.3%. Fitch expects a final regulatory decision in August 2023. In North Dakota, the company recently received regulatory approval of its settlement agreement with key intervenors which provides for a net rate increase of $15.3 million based on a 9.75% ROE (unchanged) and an equity layer of 50.81%

(51.4% previously). Fitch views prior outcomes in previous rate cases in Montana (black box settlement) and North Dakota as fair and balanced.

Supportive Ring-Fencing Provisions: Like its utility affiliates, Montana-Dakota's credit profile benefits from ring-fencing mechanisms that insulate the utility from MDU's other regulated and unregulated businesses. Ring-fencing mechanisms include no Montana-Dakota guarantees or cross-default provisions within debt agreements at other MDU entities that could impact Montana-Dakota; a prohibition on intercompany loans; and dividend payment restrictions so that Montana-Dakota may not make dividend payments that would reduce its common equity ratio below 45%.

Manageable Capex: Fitch projects capex to total $912 million over 2023-2026, with capital spending peaking in 2024-2026 at around $230 million per annum. Capex is focused on new renewable investments to replace retirements of inefficient coal plants. A key project is the construction of an 88MW simple cycle natural gas combustion turbine in North Dakota that is almost complete to replace the retirement of 144MW of coal-fired generation in 2021-2022. The gas plant is estimated to cost $73 million and has an expected in-service date later this year.

Renewables comprised 32% of MDU's electric generation resource mix for 2022 and renewable investments are recoverable under environmental rate riders in North and South Dakota while generation investments in North Dakota are also eligible for rider recovery. Fitch expects Montana-Dakota to fund capex in a conservative manner with a mix of internal cash flows, debt and parent equity infusions to align with the statutory capital structure.

Adequate Credit Metrics: Fitch projects FFO-adjusted leverage to average 4.6x in 2023-2026, consistent with a 'BBB+' utility credit profile. While a large capex program pressures credit metrics in the near-term, the benefit of timely rate case filings, riders, and tax credits from renewable investments, provides support to credit measures over the next few years.

Centennial Energy Holdings, Inc.

Improving Business Risk Profile: Given the expected spin-off of CSG in 2024, Centennial's ratings consider the relatively low-risk of its nearly 100% FERC regulated natural gas pipeline and storage business in the Bakken Basin. Centennial's operations moved approximately half of Bakken gas to consuming markets in Montana, Wyoming, Minnesota and North and South Dakota. Centennials credit profile is supported by take or pay contracts comprising over 75% of revenue with a weighted average contract length of more than four years.

Constructive Rate Case Outcome: Fitch views Centennial's latest FERC-approved rate case outcome as constructive. In January of this year the company was authorized a rate increase of $81 million based on an authorized ROE of 14.91% and an equity layer of 60% for new rates effective no later than August of 2023.

Creditworthy Counterparties: Centennial's pipeline contracts are primarily with investment grade creditworthy counterparties with a weighted average credit rating approximating 'BBB'. Notably, affiliate subsidiary Montana-Dakota is the company's largest anchor shipper accounting for approximately 43% of revenue for 2022. Centennial's three largest counterparties includes Montana-Dakota (BBB+/Stable) followed by ONEOK Rockies Midstream (parent ONEOK Inc.; BBB/Stable) and Rainbow Gas Company (not rated) which collectively comprised nearly 2/3 (43%, 12%, and 9%, respectively) of total 2022 revenue.

Strong Credit Metrics: FFO leverage is projected to remain strong and average 2.8x in 2025-2026 as compared to 2.7x in 2022. Those metrics are in line with an IDR of 'BBB+' for a 100% FERC regulated natural gas pipeline and storage system. Deleveraging will be a function of organic earnings growth and debt paydowns using proceeds from the spin-off of its construction material business earlier this year including the full repayment of legacy Knife River and CSG debt at Centennial.

Cascade Key Rating Driver

Low-Risk Business Profile: Cascade's ratings reflect the low-risk nature of its regulated gas distribution assets across its two-state service territory in Washington and Oregon and supportive rate design, including margin decoupling and fuel cost recovery, and solid customer growth. Fitch estimates Washington represented roughly 75% of Cascade's total revenue in 2022. Cascade's service territory continues to experience above average customer growth with a CAGR of 1.7% over the last five years, driven by favorable demographic trends in the Pacific Northwest. The utility accounted for approximately 22% of combined electric and gas utilities' EBITDA in 2022.

Reasonable GRC Settlement in Washington: Fitch views regulatory approval of Cascade's settlement agreement in August 2022 with key intervenors in its 2020 GRC in Washington as reasonable. The settlement agreement provides for a $7.2 million rate increase (53% of requested) based on a 9.4% ROE (unchanged) and a 47% equity layer (2.1% lower than previous rate case). The relatively reasonable outcome follows an unfavorable outcome in its prior rate case in Washington whereby Cascade received a $0.4 million rate decrease based on a 9.4% ROE. The authorized ROE is modestly below the national average of 9.6% for gas utilities in 2022. In Oregon Cascade received a favorable outcome in its last GRC in early 2021 and was authorized a rate increase of $3.2 million (71% of requested) based on a ROE of 9.4% and an equity layer of 50%.

Fitch believes the Washington regulatory compact remains somewhat challenging; authorized ROE's tend to be at or below prevailing industry averages and the use of average rate base valuations and historical test years exacerbates regulatory lag. This hinders Cascade's ability to materially improve its earned ROE and Fitch notes the utility has been earning below its authorized return for several years. A timely cadence of future rate case filings coupled with expectations for balanced regulatory outcomes should help improve earned returns and alleviate persistent regulatory lag.

Sizable Capex: Fitch estimates Cascade's capital spending to approximate $406 million through 2023-2026 with the peak occurring in 2024 at approximately $133 million and declining thereafter. Capex is earmarked for new infrastructure and replacement of aging pipes, with a portion of investments subject to timely recovery under an infrastructure tracking mechanism. Fitch expects the utility to fund capex with a balanced mix of internal cash flows, debt and equity infusions from MDU.

Pressured Credit Metrics: Cascade's FFO leverage measures are expected to weaken to an average of 6.2x through 2024 as capital spending peaks but improve thereafter as spending subsides and timely recovery of pipe replacement investments under rate riders eases the financial pressure. Fitch expects FFO leverage to strengthen to 5.0x in 2025-2026, bringing metrics back in line with ratings.

Ring-Fencing Mechanisms: Cascade's credit profile benefits from ring-fencing mechanisms that insulate the utility from MDU's other regulated and unregulated businesses. Ring-fencing mechanisms include no Cascade guarantees or cross-default provisions within debt agreements at other MDU entities that could affect Cascade, a prohibition on intercompany loans and dividend payment restrictions so that Cascade may not make dividend payments that would reduce its common equity ratio below 38%.

DERIVATION SUMMARY

MDU Resources Group, Inc.

MDU's ratings reflect an improving business risk profile focused on regulated utility operations following the expected spin-off of CSG in 2024 with the proportion of EBITDA derived from regulated operations improving to nearly 100% from 45% in 2022. CSG currently accounts for 31% of consolidated EBITDA.

MDU's closest utility peers include Black Hills Corp. (BKH; BBB+/Stable), Xcel Energy, Inc. (BBB+/Stable), and Otter Tail Corp. (BBB-/Stable). Like Xcel and BKH, MDU benefits from earnings and regulatory diversification with utility operations in multiple states. Otter Tail's earnings can be more volatile than MDU due to the ownership of cyclical manufacturing businesses that are subject to greater market competition than MDU's construction services business. Post-Spin MDU's pro forma FFO leverage are projected to weaken and average 5.0x x in 2025- 2026 from approximately 3.8x in 2022, above previous pre-spin projections of an average of 3.1x and at Fitch's negative FFO leverage sensitivity threshold of 5.0x. Fitch believes MDU's improved business risk profile that is focused on utility operations is an offset to the negative financial impacts of the separation of its construction businesses.

MDU's financial profile is stronger than BKH's and Xcel's and similar to Otter Tail's. BKH's high leverage primarily reflects its debt-funded acquisition of Black Hills Gas Holdings LLC (f/k/a SourceGas Holdings LLC) in 2016. For 2022, debt/EBITDA and FFO leverage were 3.4x and 3.8x, respectively, at MDU, 5.0x and 5.1x at Xcel, 6.8 and 6.9x at BKH, and 1.7x and 1.9x at Otter Tail.

Montana-Dakota Utilities Co.

Montana-Dakota's business risk profile as a regulated integrated utility is stronger than NorthWestern Corp. (NWE; BBB/Stable) and comparable to Otter Tail Power Co. (OTP; BBB/Stable) and Black Hills Power Inc. (BHP; BBB+/Stable). Like Montana-Dakota, BHP's credit profile benefits from balanced regulation in South Dakota, where the majority of its operations reside. NWE is a single-state utility that lacks Montana-Dakota's regulatory diversification and has faced more regulatory challenges in Montana than its utility peer.

OTP also benefits from relatively balanced regulation in its three states of operations; however, its ratings are constrained due to ownership by a weaker parent. Montana-Dakota's financial profile is stronger than NWE's, in line with OTP and weaker than that of BHP. Fitch forecasts Montana- Dakota's FFO leverage to average 4.6x through 2023-2026, in line with an average of 4.3x at OTP and worse than an average of 3.7x at BHP but better than NWE, whose FFO leverage is expected to strengthen to 5.3x during the same period.

Centennial Energy Holdings, Inc.

Centennial's ratings reflect an improving business risk profile focused on its FERC regulated pipeline business and expectations for leverage measures to remain strong due to management's pro-active efforts to strengthen the balance sheet. Earlier this year MDU spun-off its construction materials business, Knife River Corp., to its shareholders and is pursuing a similar spin-off of its Construction Services Group subsidiary which is expected to close in late 2024.

Fitch for the midstream sector generally considers $500 million in annual EBITDA as the boundary line between investment grade and below-investment grade. The long-distance regulated natural gas pipeline sector is an exception to this limitation due to extremely low business risk. Centennial's closest peers in the sector include Southern Natural Gas Company (SNG; BBB+/Stable), Southern Star Central Gas Pipeline Inc. (Southern Star; BBB/Stable), and Portland Natural Gas Transmission System (PNGTS; A-/Stable).

On an EBITDA basis, Centennial with projected EBITDA averaging $131 million in 2024-2026 is larger than PNGTS at $78 million for 2021, similar in size to Southern Star at $150 million and smaller than SNG at $398 million for the same period. Centennial is a 100% FERC regulated natural gas pipeline and storage system in the Bakken basin with the majority of its 2021 revenue coming from long-term take-or pay contracts. Like Centennial, its peers are also FERC regulated natural gas pipeline systems which Fitch views as a credit positive as it is considered lower risk than state regulation. Centennial has approximately 89% of its revenue underpinned by long-term take-or-pay contracts and compares well with PNGTS and Southern Star at 85% and 95%, respectively. Centennial's pipeline serves a demand-pull customer base, similar to peers and like SNG, serves affiliate utilities which are the anchor shippers.

Centennial has a remaining weighted average contract life of approximately four years, longer than Southern Star at roughly three years, similar to SNG at four years, and much shorter than PNGTS at 15.6 years. In terms of leverage, FFO leverage at Centennial is projected to remain strong and average 2.6x in 2024-2026, better than Southern Star at 5.6x-5.9x, similar to PNGTS at less than 3x and SNG at 2.5x-3.0x for the same period.

Cascade Natural Gas Corporation

Cascade is a local gas distribution company (LDC) with a relatively weaker business profile than LDC peers, Connecticut Natural Gas Corporation (CNG; A-/Stable), Wisconsin Gas LLC (A-/Stable) and Peoples Gas Light & Coke Co. (A-/Stable). Cascade and CNG are some of the smallest regulated utilities under Fitch's coverage and much smaller than its larger peers. Cascade's EBITDA is similar in size to CNG and about 3.0x smaller than WI Gas and about 6.0x smaller than Peoples Gas. Fitch considers Washington regulation to be relatively challenging and Connecticut regulation to be relatively balanced, while regulation in Wisconsin and Illinois are viewed as constructive.

Cascade's FFO leverage measures are expected to weaken to an average of 6.2x through 2024 as capital spending peaks but improve thereafter as spending subsides and timely recovery of pipe replacement investments under rate riders eases the financial pressure. Fitch projects Cascade's FFO leverage metrics to strengthen to 5.0x by 2025-2026, reflecting a weaker financial profile than its peers. Similarly, Fitch expects leverage metrics to strengthen to low 4x by 2023-2024 at WI Gas and to average 4.1x at Peoples Gas and 2.2x- 3.0x at CNG over the same period.

KEY ASSUMPTIONS

--Knife River spin at 2.5x leverage effective May 2023;

--10% of retained Knife River shares to be monetized in late 2023 totaling $250 million;

--Special dividend from Knife River in 2023 totaling $825 million;

--Pay down KRC and CSG debt at Centennial and pay out dividends to shareholders with proceeds;

--Spin-off off CSG in 2024;

--Targeting utility dividend payout ratio of 60%-70%;

-- $209 million of new HoldCo debt.

RATING SENSITIVITIES

MDU Resources Group, Inc.

Factors that could, individually or collectively, lead to positive rating action/upgrade:--An upgrade is not anticipated at this time, however, sustained FFO leverage below 4.0x could warrant positive rating actions.

Factors that could, individually or collectively, lead to negative rating action/downgrade:

--A material deterioration of the regulatory environments in which the utilities operate;

--Addition of significant unregulated cashflows;

--FFO leverage greater than 5.0x on a sustained basis.

Centennial Energy Holdings, Inc.

Factors that could, individually or collectively, lead to positive rating action/upgrade:

--Successful spin-off of the CSG in 2024 would likely result in a one-notch upgrade to 'BBB+' due to an improved business risk profile focused on regulated operations;

--Significant growth in scale and improvement in counterparty credit quality while debt with equity credit to operating EBITDA leverage is sustained below 2.5x.

Factors that could, individually or collectively, lead to negative rating action/downgrade:

--A significant change in cash flow stability profile and/or a move away from a current significant majority of capacity being contracted with investment-grade counterparties;

--Sustained total debt with equity credit to operating EBITDA above 3.5x;

--Failure to complete the expected spin-off of CSG in 2024 would likely result in a revision of Centennial's Outlook to Stable.

Montana-Dakota Utilities Co.

Factors that could, individually or collectively, lead to positive rating action/upgrade:

--FFO leverage below 4.0X on a sustained basis.

Factors that could, individually or collectively, lead to negative rating action/downgrade:

--A material deterioration of the North Dakota regulatory compact;

--FFO leverage greater than 5.0x on a sustained basis.

Cascade Natural Gas Corp.

Factors that could, individually or collectively, lead to positive rating action/upgrade:

--The Outlook could be revised to Stable following positive regulatory outcomes that leads to strengthening leverage measures;

--FFO leverage below 4.0x on a sustained basis.

Factors that could, individually or collectively, lead to negative rating action/downgrade:

--FFO leverage greater than 5.0x on a sustained basis over the rating horizon would likely result in a rating downgrade;

--Further deterioration of the Washington regulatory compact.

BEST/WORST CASE RATING SCENARIO

International scale credit ratings of Non-Financial Corporate issuers have a best-case rating upgrade scenario (defined as the 99th percentile of rating transitions, measured in a positive direction) of three notches over a three-year rating horizon; and a worst-case rating downgrade scenario (defined as the 99th percentile of rating transitions, measured in a negative direction) of four notches over three years. The complete span of best- and worst-case scenario credit ratings for all rating categories ranges from 'AAA' to 'D'. Best- and worst-case scenario credit ratings are based on historical performance. For more information about the methodology used to determine sector-specific best- and worst-case scenario credit ratings, visit https://www.fitchratings.com/site/re/10111579.

LIQUIDITY AND DEBT STRUCTURE

Sufficient Liquidity: Fitch deems MDU's liquidity to be sufficient. MDU had $514 million of available liquidity under its consolidated credit facilities at March 31, 2023, including $93 million of unrestricted cash and cash equivalents. At Montana-Dakota, liquidity is provided by a $175 million unsecured revolver that matures in December 2024. The revolver backstopped the utility's CP program.

At Cascade, liquidity is provided by a $100 million credit facility that matures in November 2027. Intermountain, Cascade's sister gas utility, maintains liquidity through a $100 million credit facility with a October 2027 maturity date. Centennial's $600 million credit facility expires in December 2024. Fitch expects the credit facilities to be refinanced in a timely manner prior to their expiry.

Following the holding company reorganization in 2019, the revolver and CP program at the parent has been transferred to Montana-Dakota and the parent does not have access to its own credit facility. All four bank agreements restrict debt/capitalization from exceeding 65%.

ISSUER PROFILE

MDU is a holding company of several regulated electric and gas utilities, a FERC-regulated interstate pipeline system and a construction services business. The company benefits from regulatory diversity, owning four low-risk regulated electric and gas utilities that operate in relatively balanced regulatory environments and serve parts of eight contiguous states from Minnesota to Washington.

REFERENCES FOR SUBSTANTIALLY MATERIAL SOURCE CITED AS KEY DRIVER OF RATING

The principal sources of information used in the analysis are described in the Applicable Criteria.

ESG CONSIDERATIONS

The highest level of ESG credit relevance is a score of '3', unless otherwise disclosed in this section. A score of '3' means ESG issues are credit-neutral or have only a minimal credit impact on the entity, either due to their nature or the way in which they are being managed by the entity. Fitch's ESG Relevance Scores are not inputs in the rating process; they are an observation on the relevance and materiality of ESG factors in the rating decision. For more information on Fitch's ESG Relevance Scores, visit https://www.fitchratings.com/topics/esg/products#esg-relevance-scores.

RATING ACTIONS

ENTITY / DEBT	RATING			PRIOR
Cascade Natural Gas Corporation	LT IDR	BBB+ Rating Outlook Negative	Affirmed	BBB+ Rating Outlook Stable
	ST IDR	F2	Affirmed	F2

senior unsecured	LT A- Affirmed	A-
Centennial Energy Holdings, Inc.	LT IDR BBB Rating Outlook Positive Affirmed	BBB Rating Outlook Stable
	ST IDR F2 Affirmed	F2
senior unsecured	LT BBB Affirmed	BBB
senior unsecured	ST F2 Affirmed	F2
Montana-Dakota Utilities Co.	LT IDR BBB+ Rating Outlook Stable Affirmed	BBB+ Rating Outlook Stable
	ST IDR F2 Affirmed	F2
senior unsecured	LT A- Affirmed	A-

VIEW ADDITIONAL RATING DETAILS

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PARTICIPATION STATUS

The rated entity (and/or its agents) or, in the case of structured finance, one or more of the transaction parties participated in the rating process except that the following issuer(s), if any, did not participate in the rating process, or provide additional information, beyond the issuer's available public disclosure.

APPLICABLE CRITERIA

Corporates Recovery Ratings and Instrument Ratings Criteria - Effective from 9 April 2021 to 13 October 2023 (pub. 09 Apr 2021) (including rating assumption sensitivity)

Corporate Rating Criteria - Effective from 28 October 2022 to 3 November 2023 (pub. 28 Oct 2022) (including rating assumption sensitivity)

Sector Navigators: Addendum to the Corporate Rating Criteria - Effective from 12 May 2023 to 3 November 2023 (pub. 12 May 2023)

Climate Vulnerability in Corporate Ratings Criteria - Effective from 21 July 2023 to 3 November 2023 (pub. 21 Jul 2023) (including rating assumption sensitivity)

APPLICABLE MODELS

Numbers in parentheses accompanying applicable model(s) contain hyperlinks to criteria providing description of model(s).

Corporate Monitoring & Forecasting Model (COMFORT Model), v8.1.0 (1)

ADDITIONAL DISCLOSURES

Dodd-Frank Rating Information Disclosure Form

Solicitation Status

Endorsement Policy

ENDORSEMENT STATUS

Cascade Natural Gas Corporation	EU Endorsed, UK Endorsed
Centennial Energy Holdings, Inc.	EU Endorsed, UK Endorsed
MDU Resources Group, Inc.	EU Endorsed, UK Endorsed
Montana-Dakota Utilities Co.	EU Endorsed, UK Endorsed

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FitchRatings

Fitch Downgrades CenterPoint Energy Houston Electric to 'BBB+'; Affirms CNP; Outlooks Negative

Fitch Ratings - New York - 19 February 2020:

Fitch Rating has downgraded CenterPoint Energy Houston Electric's (CEHE) Long-Term Issuer Default Rating (IDR) to 'BBB+' from 'A-'. The Rating Outlook has been revised to Negative from Stable. In addition, Fitch has affirmed CenterPoint Energy Corp.'s (CNP) Long-Term IDR at 'BBB' and has revised the Rating Outlook to Negative from Stable. A full list of rating actions follows at the end of this release.

Today's rating action follows the approval of CEHE's rate case settlement by the Public Utilities Commission of Texas (PUCT) on Feb. 14, 2020. Fitch believes that the unfavorable outcome signals a more challenging regulatory environment in Texas for CEHE. Lower authorized returns and equity capitalization, combined with tax-reform related refund will pressure CEHE's and CNP's credit metrics in the next few years. Further negative rating action is possible if CEHE's and CNP's FFO adjusted leverage sustains above 5x and 5.2x, respectively. Although the proposed sale of the Infrastructure Services business will facilitate debt reduction and improve CNP's operating risk modestly, Fitch estimates that the transaction has minimal impact on the consolidated FFO adjusted leverage ratio.

RATING ACTIONS

ENTITY/DEBT	RATING		PRIOR
CenterPoint Energy, Inc.	LT IDR BBB ⊖ Affirmed		BBB ○
	ST IDR F2 Affirmed		F2
senior unsecured	LT BBB Affirmed		BBB
junior subordinated	LT BB+ Affirmed		BB+
senior secured	LT A Downgrade		A+
preferred	LT BB+ Affirmed		BB+
senior unsecured	ST F2 Affirmed		F2
senior unsecured	ULT BBB Affirmed		BBB

senior secured	ULT A Downgrade		A+
CenterPoint Energy Houston Electric, LLC	LT IDR BBB+ ⊖ Downgrade		A- ○
	ST IDR F2 Affirmed		F2
senior unsecured	LT A- Downgrade		A
senior secured	LT A Downgrade		A+

Key Rating Drivers

Negative Rate Case: On Feb. 14, 2020, the PUCT approved CEHE's rate case settlement, authorizing a $13 million or 0.52% base rate increase. The increase reflects a 9.4% Return on Equity (ROE) and 42.5% equity capitalization, below the existing 10% authorized ROE and 45% equity ratio, and lower than the industry's average authorized ROE. The ROE is the lowest among all transmission and distribution utilities operating in Texas while the equity capitalization is average. CEHE will refund $105 million federal tax reform-related unprotected excess accumulated deferred federal income tax, or UEDIT, over a three-year period. CEHE also agreed to not file for the Distribution Cost Recovery Factor (DCRF) in 2020. New rates will take effect 45 days after the approval of the order.

Credit Metrics: The rate case has material negative impact on CEHE and CNP's credit metrics. Barring any mitigating actions, Fitch estimates that CEHE's FFO adjusted leverage will range in the high 4x to low 5x in the next three years, and that CNP's FFO adjusted leverage will hover around the 5.3x guideline ratio for a downgrade. The leverage ratio has incorporated the expected sale of the Infrastructure Services business.

Regulatory Ring-fencing Enhances Protection: The rate order will impose a set of regulatory ring-fencing measures but does not include certain dividend restrictions. The ring-fencing provisions will further enhance credit separation among CEHE, CNP and affiliates and are complimentary to the existing corporate governance structure. The existing money pool arrangement will remain.

Asset Sale Modestly Improves Business Risk: The proposed sale of the unregulated Infrastructure Services business will mildly improve CNP's credit profile, increasing its utilities earnings to 80% over the next few years from 75%. However, the transaction has minimal impact on the consolidated FFO adjusted leverage ratio, as the earnings loss will largely offset the debt reduction.

Rating Linkages: Generally, absence of guarantees and cross-defaults, and dividend restrictions among other factors render legal ties weak between CEHE and CNP. While operational and strategic ties are strong between them, a prescribed regulatory capital structure for CEHE lead to weak linkage with CNP. Fitch typically restricts the IDR notching differential to two notches.

Fitch applies a bottom-up approach in rating CEHE and CNP. CEHE's ratings reflect their stand-alone credit profile while CNP's ratings reflect a consolidated credit profile. Fitch considers CEHE stronger than CNP, due to its lower operating risks as a fully regulated transmission and distribution company. Conversely, CNP's investment in Enable and other unregulated businesses carry higher risks than the regulated operations.

Historically, high level of parent only debt (>25%) have also resulted in weaker credit metrics at CNP. Upon the reduction of equity layer at CEHE and debt paydown at CNP as a result of the sale of the Infrastructure Services business, CNP's parent-level debt is expected to decline.

Derivation Summary

CNP carries higher operating risks than the fully regulated NiSource Inc. (NiSource, BBB/Stable), due to its investment in the Enable Midstream Partners (Enable; BBB-/Stable) and other non-utility businesses. Similar to Sempra Energy (BBB+/Stable), approximately 75% of CNP's earnings (including its share of Enable's distribution) is from regulated utilities. Upon the closing of the sale of the Infrastructure Services business, utilities could represent 80% of the total earnings over the next few years. However, Fitch considers Enable's midstream business riskier than Sempra's Cameron liquefied natural gas project, which is fully contracted and has no commodity risks. CNP's utilities are more geographically diversified and more insulated from the aggressive renewable standards and wildfire risks than Sempra's California utilities. CNP and OGE Energy (BBB+/Stable) are both exposed to the commodity sensitive midstream business through Enable. CNP's utility operations are diversified, whereas OGE's only utility is concentrated in Oklahoma. CNP and OGE both experienced negative regulatory treatment. Absent any offsetting measures after the rate case, CNP's FFO-adjusted leverage is estimated to be in the low to mid-5x in the next two years, weaker than Sempra Energy's 5x and OGE Energy's 3.8x. NiSource's credit metrics were affected by the gas explosions in 2018, but expected to return to normal after receiving insurance proceeds and equity issuances.

Prior to the rate case, CEHE benefited from slightly more favorable regulatory treatment than its peers. CEHE's 2010 rate case authorized a 45% equity ratio, higher than Oncor Electric Delivery Company's (BBB+/Stable) 42.5% and AEP Texas Inc.'s (BBB+/Stable) 40%, and the same as Texas-New Mexico Power Company's (TNMP; not rated) equity ratio. CEHE's existing 10% authorized ROE was higher than AEP Texas' 9.98%, Oncor's 9.8% and TNMP's 9.65%. Going forward, CEHE's 9.4% ROE will lag behind its peers while the 42.5% equity ratio is relatively on par. Fitch estimates that CEHE's FFO adjusted leverage could range from high 4x to low 5x in the next two to three years. Oncor and AEP Texas's FFO adjusted leverage are estimated to be in high 4x for the same period.

Key Assumptions

- New rates are implemented in April 2019;

- DCRF resumes in 2021;

- Incorporated the sale of Infrastructure Services business and reduce debt at CNP;

- No mitigating actions are assumed.

RATING SENSITIVITIES

CEHE

Developments That May, Individually or Collectively, Lead to Positive Rating Action

-The Rating Outlook can be revised to Stable if FFO adjusted leverage is below 5x on a sustained basis.

Developments That May, Individually or Collectively, Lead to Negative Rating Action

-FFO-adjusted leverage exceeds 5.0x on a sustained basis;

-Termination of the two trackers TCOS and DCRF;

-Further signs of deterioration of regulatory relationship.

CNP

Developments That May, Individually or Collectively, Lead to Positive Rating Action

-The Rating Outlook can be stabilized if the CNP's FFO adjusted leverage is below 5.3x on a sustained basis;

Developments That May, Individually or Collectively, Lead to Negative Rating Action

-FFO adjusted leverage reaches 5.3x on a sustained basis;

-If CNP and Vectren's utilities' regulatory environment becomes unfavorable to the point that they are unable to receive timely and reasonable recovery in rates;

-Enable requires a meaningful amount of equity support;

-Disproportionate expansion of unregulated businesses resulting in material increase in business risk.

ESG Considerations

Unless otherwise disclosed in this section, the highest level of Environmental, Social and Governance (ESG) credit relevance is a score of '3', which indicates ESG issues are credit neutral or have only a minimal credit impact on the entity, either due to their nature or the way in which they are being managed by the entity. For more information on Fitch's ESG Relevance Scores, visit www.fitchratings.com/esg.

Additional information is available on www.fitchratings.com

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Applicable Criteria

Corporate Rating Criteria (pub. 19 Feb 2019)
Short-Term Ratings Criteria (pub. 02 May 2019)
Parent and Subsidiary Rating Linkage (pub. 27 Sep 2019)
Corporates Notching and Recovery Ratings Criteria (pub. 14 Oct 2019)
Corporate Hybrids Treatment and Notching Criteria (pub. 11 Nov 2019)

Additional Disclosures

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FitchRatings

RATING ACTION COMMENTARY

Fitch Downgrades Pinnacle West Capital & Arizona Public Service to 'BBB+'; Outlooks Remain Negative

Tue 12 Oct, 2021 - 10:52 AM ET

Fitch Ratings - Chicago - 12 Oct 2021: Fitch Ratings has downgraded the Issuer Default Ratings (IDRs) of both Pinnacle West Capital Corp. (PNW), and its regulated utility subsidiary, Arizona Public Service Co. (APS) to 'BBB+' from 'A-'. The Rating Outlook remains Negative for PNW and APS. Fitch has also downgraded the unsecured ratings of PNW and APS one-notch to 'BBB+' from 'A-' and to 'A-' from 'A', respectively. In addition, Fitch has affirmed the CP and short-term ratings of both PNW and APS at 'F2'.

The one-notch rating downgrade and Negative Outlook for PNW and APS reflect anticipation of an adverse final order in APS's pending general rate case (GRC), resulting pressure on credit metrics and a heightened risk profile. The rating action follows recent amendments to the Administrative Law Judge's (ALJ) recommended order as voted on by the Arizona Corporation Commission (ACC) that, if finalized, would reduce rates at APS more than previously anticipated and lower its authorized ROE to 8.7% from 10%.

Absent future regulatory relief or management action to rebalance its capital structure, Fitch believes FFO leverage could deteriorate to 5.0x or more for PNW and APS in 2023. In that scenario, weaker credit metrics combined with significantly higher regulatory risk would likely result in future adverse credit rating actions.

A final GRC decision expected in late-October or early November along with clarity on management's capital spending plans and funding needs will be key factors in resolving the Negative Outlooks.

KEY RATING DRIVERS

GRC Update: Fitch views ACC amendments to the ALJ's recommended order in APS's pending GRC that would result in a lower revenue requirement and significantly lower authorized ROE as punitive. Based on the ACC amendments, APS's authorized ROE would be reduced to 8.7% from 10% and recovery of investment in selective catalytic reduction (SCR) pollution controls at the Four Corners coal plant would be moved to a separate proceeding further delaying potential cost recovery. APS has been seeking recovery of SCR related costs since 2017.

While the ACC withdrew amendments to eliminate APS's fuel and purchased power adjustment mechanism, Fitch believes roll back of the cost recovery mechanism would significantly heighten business risk, underscoring the regulatory uncertainty facing APS.

Recommended ALJ Order: The ALJ recommendation calls for a revenue increase of $3.6 million based on a 9.16% ROE and an equity layer of 54.7%. APS had previously requested a revised revenue increase of $169 million based on a 10% ROE and an equity layer of 54.7%. Costs associated with the SCR's accounted for nearly half of the requested rate increase. Fitch notes that the recommended ROE of 8.7% is meaningfully below the 2020 national average of 9.4% for electric utilities and materially below APS's current authorized ROE of 10%.

Fitch's rating case reflects recent amendments to the ALJ recommended order as voted on by the ACC. The outcome of the GRC will be a key determinant of credit quality, this being APS's first rate case before the ACC in over three years based on a rate base that is 33% higher than the prior rate case.

Growing Regulatory Headwinds: Recent efforts by regulators to reduce rates, lower authorized returns and promote retail competition highlights the deterioration of the regulatory compact in Arizona. A series of recent decisions by the ACC that has delayed rate recovery and exacerbated regulatory lag have had negative implications for APS's and PNW's credit quality. In Fitch's view, recent amendments to the ALJ's recommended order by the ACC to lower rates and authorized returns, continued delays in approval of the second-step Four Corners rate increase, a recent proposal to remove the fuel and purchased power adjustor among other tracking mechanisms and an investigation into the prudency of the Solana PPA underscores regulatory risk and could result in future adverse credit rating actions.

Weakening Credit Metrics: Assuming APS receives a final order in its GRC consistent with recent ACC amendments, Fitch estimates FFO leverage metrics at both PNW and APS could weaken to 5.8x and 5.3x, respectively, by 2023, supporting the downgrade and Negative Outlook.

Large Utility Capex Program: Fitch expects capex to be elevated throughout the forecast period. Fitch notes that management has lowered the pace of its capital spending program relative to last year as it navigates an increasingly challenging regulatory environment. PNW is targeting average annual utility capex of $1.5 billion in 2021-2023, levels approximately 22% higher than the preceding three-year period but approximately $600 million less than the prior plan.

PNW is focused on achieving a cleaner generation mix while modernizing the electrical grid and spending levels support average rate base growth of 6% through 2023. Capex is earmarked for new generation, distribution and transmission investments including increasing solar generation with battery storage. Generation and distribution investments represent the lion's share of capex, accounting for approximately 75% of total expenditures.

Going forward, PNW plans to align its utility generation mix with Arizona's energy policy goals by divesting its coal fleet by 2031 and investing in new gas-fired generation and solar-battery storage investments. Due to its large capex program, Fitch expects FCF to be moderately negative through 2023, funding the majority of projected capex internally. PNW's external capital needs are expected to be funded by a balanced mix of debt and equity.

Clean Energy Plan: On Jan. 22, 2020, APS announced a self-imposed goal to deliver 100% clean, carbon-free electricity to its customers by 2050. In addition, APS intends to achieve a 2030 resource mix that is 65% clean energy with 45% from renewables while ceasing all coal-fired generation operations by 2031. The company's latest Integrated Resource Plan highlights the need for approximately 2,500MW of renewable energy, demand response, energy efficiency and energy storage resources over the next five years. The clean energy plan is consistent with the ACC proposals for increased renewable standards and should garner support from stakeholders who have been advocating for a cleaner energy future in Arizona.

Strong Economy in Arizona: Economic conditions are strong in Arizona. The utility continues to benefit from strong demographic trends including accelerated customer and retail sales growth. Customer growth approximated 2.3% and retail sales growth of 5.7% during the second quarter.

Parent and Subsidiary Linkage: Operating utility APS accounts for virtually all of parent PNW's consolidated earnings and cash flows. As such, Fitch applies a bottom up, weak parent-strong subsidiary approach in assessing parent-subsidiary rating linkage, reflecting PNW's dependence on APS to meet its obligations. APS's ratings reflect its standalone credit profile, while PNW's ratings reflect a consolidated credit profile.

Strategic and operational ties between PNW and APS are strong and include common call centers and a shared treasury team while legal ties are weak due to regulatory ring- fencing provisions at the utility. Financial ties are moderate as APS has direct access to debt capital markets, but is reliant on equity from its corporate parent. Overall, Fitch assesses parent subsidiary linkage as weak. Consequently, Fitch considers the maximum difference between the IDRs of APS and PNW to be two notches. However, PNW's IDR is the same as APS's, reflecting required support from the utility to meet corporate parent obligations and dependence of APS on equity infusions from PNW and the structural subordination of PNW's debt relative to APS.

ESG RELEVANCE FACTOR THAT IS A KEY RATING DRIVER

ESG Factors: Fitch has revised the ESG relevance score to '5' for '4' for both Social - Human Rights, Community Relations, Access & Affordability and Social - Customer Welfare-Fair Messaging, Privacy & Data Security factors for both PNW and APS to reflect recent deterioration in the regulatory environment in Arizona and expectations for a challenging decision in APS's pending GRC. Regulatory risk has increased following a recent decision by the ACC to reduce customer rates and authorized returns. This has a negative impact on the credit profile and is relevant to the ratings in conjunction with other factors.

DERIVATION SUMMARY

Pinnacle West Capital Corp.:

Pinnacle West Capital Corp.'s credit profile is in line with lower rated peer utility parent holding companies DTE Energy Co. (BBB/Stable) and CMS Energy Corp. (BBB/Stable). A weakening financial profile resulting from regulatory lag due to a deteriorating regulatory environment has pressured credit metrics, which are in line with 'BBB' peers. While the regulatory environment in Michigan remains supportive, the regulatory environment in

Arizona has become challenging as evidenced by the punitive recommended order in APS's pending GRC and recent amendments voted out by the commission. For 2020, FFO adjusted leverage at PNW was 5.6x, worse than DTE at 4.7x but better than CMS at 6.3x.

PNW's business risk profile reflects ownership of sole subsidiary APS Co. and is comparable to peers with predominantly electric operations in single state jurisdictions. PNW's regulated utility operations comprise 100% of EBITDA and its business risk is similar to CMS -- which derives approximately 95% of EBITDA from its regulated utility and DTE -- which derives more than 90% of EBITDA from regulated utility businesses. In terms of scale, PNW's utility operations are the largest in Arizona with total assets of $21 billion as of 2020 but are smaller in size relative to CMS and DTE. DTE and CMS are the largest utility providers in Michigan with total assets of $50 billion and $30 billion as of 2020, respectively.

Arizona Public Service Company:

The credit profile of APS is weaker than utility peers DTE Electric Co. (A-/Stable) and Florida Power and Light Co. (A/Stable). APS's credit profile is comparable with peers that have sizable electric utility operations in single-state jurisdictions with historically constructive regulatory environments. The regulatory environment in Arizona has deteriorated meaningfully becoming significantly more challenging from a credit perspective compared to Michigan or Florida. The ACC appears to be focused on potential overearnings and reducing customer rates. This is most evident in the ALJ's unfavorable recommended order in APS's latest GRC and recent amendments by the ACC to the ALJ's recommended order.

Credit metrics for APS are weaker than peers due to regulatory lag resulting from a protracted GRC proceeding during a period of heavy capex. For 2020, FFO adjusted leverage at APS was 5.2x, worse than DTE Electric at 3.9x and Florida Power and Light Co. at 2.9x. In terms of scale, APS's utility operations are the largest in Arizona but smaller relative to DTE Electric and Florida Power and Light

KEY ASSUMPTIONS

--Assumes a rate reduction based on 8.7% ROE;

--Continued customer growth averaging 2% per annum;

--Capex averaging $1.5 billion per annum through 2023.

RATING SENSITIVITIES

PNW:

Factors that could, individually or collectively, lead to positive rating action/upgrade;

--A positive rating action is unlikely at this time given the Negative Outlook;

--However, improvement in the regulatory compact in Arizona could stabilize the Negative Rating Outlook;

--Sustained FFO leverage of better than 4.0x along with an improving regulatory compact could lead to a favorable rating action.

Factors that could, individually or collectively, lead to negative rating action/downgrade:

--Continued deterioration in the regulatory compact in Arizona.

--A material increase in parent-level debt;

--A downgrade at APS;

--Sustained FFO leverage greater than 5.0x.

APS:

Factors that could, individually or collectively, lead to positive rating action/upgrade:

--A positive rating action is unlikely at this time given the Negative Outlook;

--However, improvement in the regulatory compact in Arizona could stabilize the Negative Outlook;

--Sustained FFO leverage of better than 4.0x along with an improving regulatory compact could lead to a favorable rating action.

Factors that could, individually or collectively, lead to negative rating action/downgrade:

--Continued deterioration in the regulatory compact in Arizona;

--Sustained FFO leverage greater than 5.0x.

BEST/WORST CASE RATING SCENARIO

International scale credit ratings of Non-Financial Corporate issuers have a best-case rating upgrade scenario (defined as the 99th percentile of rating transitions, measured in a positive direction) of three notches over a three-year rating horizon; and a worst-case rating downgrade scenario (defined as the 99th percentile of rating transitions, measured in a negative direction) of four notches over three years. The complete span of best- and worst-case scenario credit ratings for all rating categories ranges from 'AAA' to 'D'. Best- and worst-case scenario credit ratings are based on historical performance. For more information about the methodology used to determine sector-specific best- and worst-case scenario credit ratings, visit https://www.fitchratings.com/site/re/10111579.

LIQUIDITY AND DEBT STRUCTURE

Sufficient Liquidity: Fitch considers liquidity for PNW to be adequate with $709 million of available liquidity under its consolidated credit facilities as of June 30, 2021, including $14 million of unrestricted cash and cash equivalents. PNW's liquidity is provided by a $200 million unsecured credit facility that matures in May 2026 and a $150 million term loan that matures in June 2022. APS's liquidity is provided by two $500 million unsecured credit facilities that mature in May 2026. These facilities support its $750 million CP program. PNW and APS can upsize their $200 million and $500 million credit facilities to $300 million and $700 million, respectively, with lender consent.

The credit facilities are subject to a maximum debt/capitalization covenant of 65% and as of June 30, 2021, PNW and APS complied with debt/capitalization ratios of 55% and 50% as defined under the agreement. APS requires modest cash on hand and, being a summer peaking utility, capital needs are typically highest during the second and third quarters. PNW's long-term debt maturities are minimal over the next five years and includes $250 million in 2024 and $300 million in 2025 at APS.

ISSUER PROFILE

PNW is a parent holding company which derives virtually all of its revenue from its wholly owned sole operating subsidiary, APS. APS is a regulated vertically integrated electric utility, serving 1.3 million customers in a 34,646-square-mile service territory. APS is the largest electric utility in Arizona and serves most of the Phoenix metropolitan area.

REFERENCES FOR SUBSTANTIALLY MATERIAL SOURCE CITED AS KEY DRIVER OF RATING

The principal sources of information used in the analysis are described in the Applicable Criteria.

ESG CONSIDERATIONS

ESG Factors: We have revised the ESG relevance score to '5' for '4' for both Social - Human Rights, Community Relations, Access & Affordability and Social - Customer Welfare-Fair Messaging, Privacy & Data Security factors for both PNW and APS to reflect recent deterioration in the regulatory environment in Arizona and expectations for a challenging decision in APS's pending GRC. Regulatory risk has increased following a recent decision by the ACC to reduce customer rates and authorized returns. This has a negative impact on the credit profile and is relevant to the ratings in conjunction with other factors.

In 2019, both PNW and APS were assigned an ESG relevance score of '4' for Social issues following complaints of excessive bills by customers following the implementation of time-of-use rates. Regulators have found that customer education and outreach efforts were insufficient, which has led to increased regulatory scrutiny and the absence of rate recovery.

Unless otherwise disclosed in this section, the highest level of ESG credit relevance is a score of '3'. This means ESG issues are credit-neutral or have only a minimal credit impact on the entity, either due to their nature or the way in which they are being managed by the entity. For more information on Fitch's ESG Relevance Scores, visit www.fitchratings.com/esg.

RATING ACTIONS

ENTITY/DEBT	RATING			PRIOR
Arizona Public Service Company	LT IDR	BBB+ Rating Outlook Negative	Downgrade	A- Rating Outlook Negative
	ST IDR	F2	Affirmed	F2
• senior unsecured	LT	A-	Downgrade	A

ENTITY/DEBT	RATING			PRIOR
• senior unsecured	LT	A-	Downgrade	A

VIEW ADDITIONAL RATING DETAILS

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APPLICABLE CRITERIA

Parent and Subsidiary Linkage Rating Criteria (pub. 26 Aug 2020)

Corporate Rating Criteria -- Effective from 21 December 2020 to 15 October 2021 (pub. 21 Dec 2020) (including rating assumption sensitivity)

Corporates Recovery Ratings and Instrument Ratings Criteria (pub. 09 Apr 2021) (including rating assumption sensitivity)

Sector Navigators - Addendum to the Corporate Rating Criteria - Effective from 30 April 2021 to 15 October 2021 (pub. 30 Apr 2021)

APPLICABLE MODELS

Numbers in parentheses accompanying applicable model(s) contain hyperlinks to criteria providing description of model(s).

Corporate Monitoring & Forecasting Model (COMFORT Model), v7.9.0 (1)

ADDITIONAL DISCLOSURES

Dodd-Frank Rating Information Disclosure Form

Solicitation Status

Endorsement Policy

ENDORSEMENT STATUS

Arizona Public Service Company	EU Endorsed, UK Endorsed
Pinnacle West Capital Corporation	EU Endorsed, UK Endorsed

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Transcript of Chair Powell's Press Conference
December 13, 2023

CHAIR POWELL. Good afternoon. My colleagues and I remain squarely focused on our dual mandate to promote maximum employment and stable prices for the American people.

As we approach the end of the year, it's natural to look back on the progress that has been made toward our dual-mandate objectives. Inflation has eased from its highs, and this has come without a significant increase in unemployment. That's very good news. But inflation is still too high, ongoing progress in bringing it down is not assured, and the path forward is uncertain. As we look ahead to next year, I want to assure the American people that we're fully committed to returning inflation to our 2 percent goal. Restoring price stability is essential to achieve a sustained period of strong labor market conditions that benefit all.

Since early last year, the FOMC has significantly tightened the stance of monetary policy. We've raised our policy interest rate by 5¼ percentage points and have continued to reduce our securities holdings at a brisk pace. Our actions have moved our policy rate well into restrictive territory, meaning that tight policy is putting downward pressure on economic activity and inflation, and the full effects of our tightening likely have not yet been felt.

Today, we decided to leave our policy interest rate unchanged and to continue to reduce our securities holdings. Given how far we have come, along with the uncertainties and risks that we face, the Committee is proceeding carefully. We will make decisions about the extent of any additional policy firming and how long policy will remain restrictive based on the totality of the incoming data, the evolving outlook, and the balance of risks. I will have more to say about monetary policy after briefly reviewing economic developments.

Recent indicators suggest that growth of economic activity has slowed substantially from the outsized pace seen in the third quarter. Even so, GDP is on track to expand around

2½ percent for the year as a whole, bolstered by strong consumer demand as well as improving supply conditions. After picking somewhat over the—up somewhat over the summer, activity in the housing sector has flattened out and remains well below the levels of a year ago, largely reflecting higher mortgage rates. Higher interest rates also appear to be weighing on business fixed investment. In our Summary of Economic Projections (SEP), Committee participants revised up their assessments of GDP growth this year but expect growth to cool, with the median projection falling to 1.4 percent next year.

The labor market remains tight, but supply and demand conditions continue to come into better balance. Over the past three months, payroll job gains averaged 204,000 jobs per month, a strong pace that is nevertheless below that seen earlier in the year. The unemployment rate remains low at 3.7 percent. Strong job creation has been accompanied by an increase in the supply of workers. The labor force participation rate has moved up since last year, particularly for individuals aged 25 to 54 years, and immigration has returned to pre-pandemic levels.

Nominal wage growth appears to be easing, and job vacancies have declined. Although the jobs-to-workers gap has narrowed, labor demand still exceeds the supply of available workers. FOMC participants expect the rebalancing in the labor market to continue, easing upward pressures on inflation. The median unemployment rate projection in the SEP rises somewhat from 3.8 percent at the end of this year to 4.1 percent at the end of next year.

Inflation has eased over the past year but remains above our longer-run goal of 2 percent. Based on the consumer price index and other data, we estimate that total PCE prices rose 2.6 percent over the 12 months ending in November and that, excluding the volatile food and energy categories, core PCE prices rose 3.1 percent.

The lower inflation readings over the past several months are welcome, but we will need to see further evidence to build confidence that inflation is moving down sustainably toward our goal.

Longer-term inflation expectations appear to remain well anchored, as reflected in a broad range of surveys of households, businesses, and forecasters, as well as measures from financial markets. As is evident from the SEP, we anticipate that the process of getting inflation all the way to 2 percent will take some time. The median projection in the SEP is 2.8 percent this year, falls to 2.4 percent next year, and reaches 2 percent in 2026.

The Fed's monetary policy actions are guided by our mandate to promote maximum employment and stable prices for the American people. My colleagues and I are acutely aware that high inflation imposes significant hardship, as it erodes purchasing power, especially for those least able to meet the higher costs of essentials like food, housing, and transportation. We are highly, highly attentive to the risks that high inflation poses to both sides of our mandate, and we are strongly committed to returning inflation to our 2 percent objective.

As I noted earlier, since early last year, we have raised our policy rate by 5¼ percentage points, and we have decreased our securities holdings by more than $1 trillion. Our restrictive stance of monetary policy is putting downward pressure on economic activity and inflation. The Committee decided at today's meeting to maintain the target range for the federal funds rate at 5¼ to 5½ percent and to continue the process of significantly reducing our securities holdings.

While we believe that our policy rate is likely at or near its peak for this tightening cycle, the economy has surprised forecasters in many ways since the pandemic, and ongoing progress—sorry—ongoing progress toward our 2 percent inflation objective is not assured. We are prepared to tighten policy further if appropriate. We're committed to achieving a stance of monetary policy that is sufficiently restrictive to bring inflation sustainably down to 2 percent over time and to keeping policy restrictive until we're confident that inflation is on a path to that objective.

In our SEP, FOMC participants wrote down their individual assessments of an appropriate path for the federal funds rate based on what each participant judges to be the most likely scenario going forward. While participants do not view it as likely to be appropriate to raise interest rates further, neither do they want to take the possibility off the table. If the economy evolves as projected, the median participant projects that the appropriate level of the federal funds rate will be 4.6 percent at the end of 2024, 3.6 percent at the end of 2025, and 2.9 percent at the end of 2026, still above the median longer-term rate.

These projections are not a Committee decision or plan; if the economy does not evolve as projected, the path of policy will adjust as appropriate to foster our maximum-employment and price-stability goals.

In light of the uncertainties and risks, and how far we have come, the Committee is proceeding carefully. We will continue to make our decisions meeting by meeting, based on the totality of the incoming data and their implications for the outlook for economic activity and inflation, as well as the balance of risks. In determining the extent of any additional policy firming that may be appropriate to return inflation to 2 percent over time, the Committee will take into account the cumulative tightening of monetary policy, the lags with which monetary policy affects economic activity and inflation, and economic and financial developments. We remain committed to bringing inflation back down to our 2 percent goal and to keeping longer-term inflation expectations well anchored. Restoring price stability is essential to set the stage for achieving maximum employment and stable prices over the longer run.

To conclude: We understand that our actions affect communities, families, and businesses across the country. Everything we do is in service to our public mission. We at the Fed will do everything we can to achieve our maximum-employment and price-stability goals.

Thank you. I look forward to your questions.

MICHELLE SMITH. Let's go to Chris Rugaber.

CHRISTOPHER RUGABER. Thank you. Chris Rugaber at Associated Press. I wanted to ask, how should we interpret the addition of the word "any" before "additional . . . firming" in the statement? I mean, does that mean that you're pretty much done with rate hikes and the Committee has shifted away from a tightening bias and toward a more neutral stance? Thank you.

CHAIR POWELL. So—specifically on "any": We do say that "in determining the extent of any additional policy firming that may be appropriate," so "any additional policy firming"—that sentence. So we added the word "any" as an acknowledgement that we believe that we are likely at or near the, the peak rate for this cycle. Participants didn't write down additional hikes that we believe are likely, so that's what we wrote down. But participants also didn't want to take the possibility of further hikes off the table. So that's really what we were thinking.

MICHELLE SMITH. Steve.

STEVE LIESMAN. Steve Liesman, CNBC. Happy holidays, Mr. Chairman. Fed Governor Chris Waller said that if inflation continues to fall, then the Fed in the next several months could be cutting interest rates. I wonder if you could comment on whether you agree with Fed Governor Waller on that, that the Fed would become more restrictive if it didn't cut rates if inflation fell. Thank you, sir.

CHAIR POWELL. So, of course, I don't comment on, on any other officials, even those who work at the Fed. But I'll—but I'll try to answer your question more broadly. So the way—the way we're looking at it is, is really this. When we started out, right, we said the first question is, how fast to move, and we moved very fast. The second question is, you know, really, how high to raise the policy rate? And that's really the question that we're still on here. We're, we're very focused on that, as I—as I mentioned. People generally think that we're at or near that and, and think it's not likely that we will hike, although they don't take that possibility off the table. So that's—when you get to that question, and that's your answer, there's a natural—naturally, it begins to be the next question, which is when it will become appropriate to begin dialing back the amount of policy restraint that's in place.

So that's really the next question, and that's what people are thinking about and, and talking about. And I would just say this. We are seeing, you know, strong growth that is—that appears to be moderating; we're seeing a labor market that is coming back into balance by so many measures; and we're seeing inflation making real progress. These are the things we've been wanting to see. We can't know. We still have a ways to go. No one is declaring victory. That would be premature. And we can't be guaranteed of this progress [continuing]. So we're, we're moving carefully in making that assessment of whether we need to do more or not. And that's, that's really the question that we're on. But, of course, the other question, the question of when will it become appropriate to begin dialing back the amount of policy restraint in place, that, that begins to come into view and is clearly a discussion—topic of discussion out in the world and also a discussion for us at our meeting today.

STEVE LIESMAN. Can you give some color as to the nature of that discussion today? Thank you.

CHAIR POWELL. Sure. So it, it comes up in this way today. Everybody wrote down an SEP forecast. So many people mentioned what their—what their rate forecast was. And there was no back-and-forth, no attempt to sort of reach agreement like, "This is what I wrote down; this is what I think," that kind of thing, and a preliminary kind of a discussion like that. Not everybody did that, but many people did. And then, and I would say, there's a general expectation that this will be—this will be a topic for us, looking ahead. That, that's really what happened in today's meeting. I can't do the head count for you in real time. But that's generally what happened today.

STEVE LIESMAN. Thank you.

MICHELLE SMITH. Let's go to Rachel.

RACHEL SIEGEL. Hi, Chair Powell. Rachel Siegel from the *Washington Post.* Thanks for taking our questions. At this point, can you confidently say that the economy has avoided a recession and isn't heading for one now? And if the answer is "no," I'm curious about what you'd still be looking for. Thanks.

CHAIR POWELL. I think you can say that there's little basis for thinking that the economy is in a recession now. I would say that.

I think there's, there's always a probability that, that there will be a recession in the next year, and it's a meaningful probability no matter what the economy is doing. So it's always a real possibility. The question is, is it—so it's a possibility here. I have always felt, since the beginning, that there was a possibility, because of the unusual situation, that the economy could cool off in a way that enabled inflation to come down without the kind of large job losses that have often been associated with high inflation and tightening cycles. So far, that's what we're seeing. That's what many forecasters, on and off the Committee, are seeing. This result is not guaranteed. It is—it is far too early to declare victory. And there are certainly risks. It's certainly possible that, that the economy will behave in an unexpected way. It has done that repeatedly through the post—in the post-pandemic period. Nonetheless, where we are is, is we see the things that I—that I mentioned.

RACHEL SIEGEL. I'm curious, if you're looking back on the past year, you talked about "navigating by the stars under cloudy skies." Can you talk about some of the ways in which the economy surprised you most this year, where you thought it would behave in one way and had to pivot to respond? Thanks.

CHAIR POWELL. So I think forecasters generally, if you go back a year, were very broadly forecasting a recession for this year, for 2023. And not only did that not happen—that includes Fed forecasters and really, essentially, all forecasters; a very high proportion of forecasters predicted very weak growth or a recession—not only did that not happen, we actually had a very strong year, and that was a combination of, of strong demand but also of real gains on the supply side.

So this was the year when labor force participation picked up, where immigration picked up, where the distortions to supply and demand from the pandemic—you know, the shortages and the bottlenecks—really began to unwind. So we had significant supply-side gains with strong demand, and we got what looks like a 2½ percent-plus, or a little more than that, growth year at a time when potential growth this year might even have been higher than that, just because of the healing on the supply side. So that was a surprise to just about everybody.

I think the inflation forecast is roughly, roughly what people wrote down a year ago, but in a very different setting. And I would say the labor market, because of the stronger growth, has also been significantly better. If you look back at the SEP from a year ago, there was a significant increase in, in unemployment. It didn't really happen. We're still at 3.7 percent. So we've seen, you know, strong growth, still a tight labor market but one that's coming back into balance with the—with support from the supply side, a greater supply of labor. It's a—you know, that's, that's what we see, and I think that combination was, was not anticipated broadly.

MICHELLE SMITH. Howard.

HOWARD SCHNEIDER. Thanks. Howard Schneider with Reuters, and thanks for taking the questions. I, I wonder if you could give a little more color or detail on what—on what motivates the lower rates next year, whether it's a coincidence, for example, that the spread between PCE inflation, core inflation, and the federal funds rate stays constant over the year. Are you simply calibrating against the fall in prices, in the price level that you're expecting, in the rate of inflation that you're expecting as opposed to supporting the economy?

CHAIR POWELL. Nothing quite that mechanical is happening. The SEP really is, is a bottoms-up—built from the bottom up, right? So I think people are looking at what's happening in the economy. And I think if you look at the big difference from September in the SEP, [it is that] the expectations for inflation this year, both headline and core, have come down, you know, really significantly in three months. That's a big piece of, of this. At the same time, [real GDP] growth has turned out to be very strong in the third quarter. [Now it] is slowing, we believe, as, as appropriate. And we've got—we've had several labor market reports, which suggest, again, significant progress toward greater balance across a very—a broad range of indicators. You're seeing so many of the indicators coming back to normal, not all of them. But so I think that people look at that, and they write down their—basically, each individual writes down a forecast and a rate forecast that goes with that forecast. We tabulate them and, and publish it. And so it's not—it isn't—you ask about real rates, I take it?

HOWARD SCHNEIDER. Yes.

CHAIR POWELL. You know, that's—that is—that is something that we're very conscious of, and aware of, and monitor, and it's certainly a big part of—it's a part of how we think about things. But, really, it's broader financial conditions that matter. And, as you well know, it's so hard to know exactly, you know, what the—what the real rate is or exactly how tight policy is at any given time. So you couldn't follow that like it was a rule and think that you would get the right answer all the time, but it's certainly something that we're focused on. And, indeed, if you look at the projections, I think the expectation would be that the real rate is declining as we—as we move forward.

HOWARD SCHNEIDER. It sounds like the discussion—if I could follow up—has, has already kind of begun. I'm wondering, just related to, to Steve's question, how the—how the tactics of this play out given the slowing of inflation and the fact that the deeper you get into 2024, the closer you get to a presidential election. Do you want to front-load this, in other words?

CHAIR POWELL. Yeah. No, we—we're—we don't think about political events. We don't think about politics. We think about what's the right thing to do for the economy. The minute we start thinking about those things—you know, we just can't do that. We have to think, what's the right thing? We'll do the things that we think are right for the economy at the time we—when we think is the right time. That's what we'll always do.

So I mentioned we're moving carefully. One of the things we're moving carefully about is that decision over—that assessment, really—over whether, whether we've done enough, really. And you see that people are not writing down rate hikes. That's, that's us thinking that we have done enough but not, not feeling that really strongly, confidently and not wanting to take the possibility of a rate hike off the table. Nonetheless, it's not the base case anymore, obviously, as it was, you know, 60, 90 days ago. So that's, that's how we're—that's how we're approaching things. And, and, you know, as I mentioned, we wrote down this SEP, and it talks about—people have individual assessments of when it will be appropriate to, you know, to start to dial back on, on the tight policy we have in place, and that's a discussion we'll be having going forward. But that's another assessment that we're going to make very carefully, so as time goes forward.

MICHELLE SMITH. Nick.

NICK TIMIRAOS. Nick Timiraos of the *Wall Street Journal.* Chair Powell, you've argued over the last year that policy tightening started before you actually lifted off because the market anticipated your moves and tightened on your behalf. The market is now easing policy on your behalf by anticipating a funds rate by next September that's a full point below the current level, with cuts beginning around March. Is this something that you are broadly comfortable with?

CHAIR POWELL. So this last year has been remarkable for the, the sort of seesaw thing, the back-and-forth we've had over the course of the year of markets moving away and moving back and that kind of thing. So, and what I would just say is that we, we focus on what we have to do and how we need to use our tools to achieve our goals, and that's what we really focus on. And people are going to have different forecasts about the economy, and they're going to—those are going to show up in market conditions, or they won't, you know. But in any case, we have to do what we think is right.

And, you know, in the long run, it's important that financial conditions become aligned or are aligned with what we're trying to accomplish, and, in the long run, they will be, of course, because we will do what it takes to get to our goals. And, ultimately, that will mean that financial conditions will, will come along. But in the meantime, there can be back-and-forth, and, you know, I'm just focused on what's the right thing for us to do. And my colleagues are focused on that, too.

NICK TIMIRAOS. The markets seem to think inflation is coming down credibly. Do you believe we're at the point where inflation is coming down credibly?

CHAIR POWELL. Listen, I welcome the progress. I think it's, it's really good to see the progress that we're making. I think if you look at the 12-month—look at the 6-month measures, you see very low numbers. If you look at 12-month measures, you're still well above 2 percent. You're actually above 3 percent on core, through November, PCE [inflation]. That isn't to say—I'm not, you know, calling into question the progress. It's great. We just need to see more. We need to see, you know, continued further, further progress toward getting back to 2 percent. That's, that's what we need to see.

So, you know, our—it's our job to restore price stability. And that—it's one of our two jobs, along with maximum employment, and they're equal. So we're very focused on, on, you know, doing that. As I mentioned, we're moving carefully at this point. We're pleased with the progress, but, but we see the need for further progress, and I think—I think it's fair to say there is a lot of uncertainty about going forward. We've seen the economy move in surprising directions, so we're just going to need to see more further progress.

MICHELLE SMITH. Jeanna.

JEANNA SMIALEK. Jeanna Smialek, *New York Times.* Thanks for taking our questions. In the SEP from today, [real GDP] growth is notably below potential in 2024. If growth were to surprise us again in the way that it has for years now by being stronger than expected next year, would it still be possible to cut rates? Or, put another way, is below-trend growth necessary to cut rates, or would continued progress on inflation alone be sufficient?

CHAIR POWELL. So we'll, we'll look at the totality of the data. Growth is one thing, so is inflation, so is labor market data. So we'd, we'd look at the totality. As we—as we make decisions about policy changes going forward, we're going to be looking at all those things and, particularly, about the—as they affect the outlook. So it's ultimately all about the outlook and the balance of risks as well. So that's what—that's what we'd be looking for.

If we have stronger growth, you know, that'll be good for people. That'll be good for the labor market. It might actually mean that it takes a little longer to get inflation down to 2 percent. We will get it down to 2 percent, but, you know, if we see stronger growth, we'll—we will set policy according to what we actually see. And, and so that's how I would answer.

JEANNA SMIALEK. I guess the—I guess the question I'm asking, if you don't mind a quick follow-up, I guess the question I'm asking is, is above-trend growth itself a problem?

CHAIR POWELL. It's only a problem inso—it's not itself a problem. It's only a problem insofar as it makes it more difficult for us to achieve our goals. And, you know, if you have—if you have growth that's robust, what that will mean is probably it will keep the labor market very strong. It probably will, will place some upward pressure on inflation. That could mean that it takes longer to get to 2 percent inflation. That could mean we need to keep rates higher for longer. It could even mean, ultimately, that we would need to hike again. It just is—it's the way, the way our policy works.

MICHELLE SMITH. Let's go to Neil.

NEIL IRWIN. Hi, Chair Powell. Neil Irwin with Axios. How do you interpret the state of the labor market right now? And, in particular, you've referred even today to evidence that it's coming into better balance. What would you need to see to conclude that it has reached that balance?

CHAIR POWELL. So on, on the better-balance side, there are just a lot of things. It's—you see—you see job growth still strong but moving back down to more sustainable levels, given population growth and labor force participation. The things that are not quite—but let me go on with that list. You know, claims are low. If you look at surveys of businesses, they're, they're—sort of the era of this frantic labor shortage, [those kinds of worker shortages] are behind us, and they're seeing a shortage of labor as being significantly alleviated. If you look at shortages of workers, whereas they thought job, job availability was the highest that it'd ever been or close to it, that's now down to more normal levels by so many measures—participation, unemployment—so many measures: the unemployment—job openings, quits, all of those things.

So wages are still running a bit above what would be consistent with 2 percent inflation over a long period of time. They've been gradually cooling off. But if wages are running around 4 percent, that's still a bit above, I would say. And I guess there, there are just a couple of other—the unemployment rate is very, very low. And these are—but, but I would just say, overall, the development of the labor market has been very positive. It's been a good time for workers to find jobs and get solid wage increases.

MICHELLE SMITH. Claire.

CLAIRE JONES. Claire Jones, *Financial Times.* You know, I'd say the mood among economists at the moment seems to be one of cautious optimism, which is somewhat corroborated by your forecast by the sense that we are going to have a soft landing. Yet when we—when we hear from the general public, there's a lot of discord about economic conditions. What do you think explains this disconnect, and does it matter for policymakers?

CHAIR POWELL. It may be. A common theme is that, while inflation is coming down, and that's very good news, the price level is not coming down. Prices of some, some goods and services are coming down. But overall, in the aggregate, the price level is not. So people are still living with high prices, and that's, that's not—that is something that people don't like. And, you know, so what will happen with that is, wages are now—[changes in] real wages are now positive. So [nominal] wages are now moving up more than inflation, as inflation comes down. And so that might help improve the mood of people.

But we do see those—we see those public opinion surveys. The thing that we can do is to do our jobs, which is to use our tools to foster price stability, which has such great benefits over such long periods of time, and which is the thing that really enables us to work for and achieve an extended period of high employment, which is so beneficial for, you know, families and, and companies around the country.

MICHELLE SMITH. Victoria.

VICTORIA GUIDA. Hi. Victoria Guida with Politico. I wanted to ask, you know, on, on the flip side of if things start to deteriorate rapidly, if we do fall into a recession, if we do start to see unemployment rise, at sort of the levels of inflation that we're seeing now, how would you all think about that in terms of rate cuts? Would that be a sign that you've, you've done your job demand-wise?

CHAIR POWELL. Sorry—if?

VICTORIA GUIDA. If, if the economy starts to—looks like it's starting to fall into a recession; if, if the jobless rate starts to rise.

CHAIR POWELL. That's not something we're hoping to see. Obviously, we're hoping to, to see something very different—which is a continuation of what we have seen, which is the labor market coming into better balance without a significant increase in unemployment, inflation coming down without a significant increase in unemployment, and growth moderating without a significant increase in unemployment. That's what we're, we're trying very much to achieve and not something that we're looking to see.

VICTORIA GUIDA. But, but would you take that as a signal that you should cut rates?

CHAIR POWELL. You know, obviously, what we'll do is we'll look at the totality of the data, as I've mentioned a couple times, and, certainly, the labor data would be important in that. And, you know, if you—if you can describe a situation like that where if, if there were the beginning of a recession or something like that, then, yes, that would certainly weigh heavily on that decision.

MICHELLE SMITH. Michael McKee.

MICHAEL MCKEE. Michael McKee from Bloomberg Television and Radio. Mr. Chairman, you were, by your own admission, behind the curve in starting to raise rates to fight inflation, and you said earlier, again, "the full effects of our tightening (cycle) have not yet been felt." How will you decide when to cut rates, and how will you ensure you're not behind the curve there?

CHAIR POWELL. So we're, we're aware of the risk that we would hang on too long. You know, we know that that's a risk, and we're very focused on not making that mistake. And we do regard the two—you know, we've come back into a better balance between the risk of overdoing it and the risk of underdoing it. Not only that, we were able to focus hard on the—on the price-stability mandate. And we're getting back to the point where—which is what you do when you're very far from, from one of them, one of the two mandates—you're getting now back to the point where both mandates are important, and they're, they're more in balance, too. So I think we'll be—we'll be very much keeping that in mind, as we make policy going forward.

And the things we'll be looking at, I've already described. You know, we're, we're obviously looking hard at what's happening with demand, and what we see? We see the same thing other people see, which is a strong economy, which really put up quite a performance in 2023. We see good evidence and good reason to believe that growth will come in lower next year. And you see what the forecasts are. I think the median growth—median participant wrote down 1.4 percent growth, but, you know, we'll have to see. It's very hard to predict. We'll also be looking to see progress on inflation and, you know, the labor market remaining strong but, but ideally, without seeing the kind of large increase in unemployment that happens sometimes.

MICHAEL MCKEE. If I could follow up: When you begin the cutting cycle, will it be essentially run the same way you do it now with raising rates, where you basically do trial and error, cut and see what happens, or will you tie it to some particular measure of progress?

CHAIR POWELL. We haven't typically tried to articulate, with one exception, really specific target levels, which was if you—some of you will remember the thresholds that we used in, I guess, 2013. I don't—the answer is, these are things that we haven't, you know, really worked out yet. We're sort of just at the beginning of, of that discussion.

MICHELLE SMITH. Edward.

EDWARD LAWRENCE. Thank you, Mr. Chairman. Edward Lawrence of Fox Business. So if the Fed cuts rates as the dot plot is, is showing, about 75 basis points, does that signal that there's a belief of weakness next year in the economy?

CHAIR POWELL. It wouldn't, if that were to—first of all, let me just say, that isn't a plan. That's, that's just cumulating what people wrote down. So that's not something—you know this, but allow me to say it again: We don't debate or discuss what the right, you know, whose SEP is right. We just say what they are, and we tabulate them and publish them. So and it's, you know, it's important for people to know that. But it wouldn't need to be a sign of—it could just be a sign that the economy is normalizing, and it doesn't need the tight policy. It depends on—the economy can evolve in many different ways, right? So but, but it could be more of what I just described.

EDWARD LAWRENCE. And you focused on core inflation, we've heard from—in other meetings. How sticky is core inflation right now?

CHAIR POWELL. Well, that's what we're finding out, and we've, you know, we've seen real progress in, in core inflation. It has been sticky, and famously, the service sector is thought to be stickier, but we've actually seen reasonable progress in nonhousing services, which was the area where, where you would expect to see less progress. We are seeing some progress there, though. And, in fact, all three of the categories of core [prices] are now contributing: goods, housing services, nonhousing services. They're all contributing in different—at different levels, you know, meeting by meeting—or, rather, report by report. So, yeah.

MICHELLE SMITH. Okay. Let's go to Catarina.

CATARINA SARAIVA. Catarina Saraiva of Bloomberg News. Thanks for taking our questions. I just wanted to ask a little bit about, you know, we had some pretty positive data this, you know, this morning and yesterday. I'm assuming those were not incorporated into the forecast we see today, but I just wanted to ask, you know, how that kind of adds to your thinking, you know, on the inflation outlook.

CHAIR POWELL. Right. So we got—we got CPI the morning of the first day, and we got PPI the next day, which informs the, you know, the translation into PCE [inflation]. So it's very late in the game, you know, to—but nonetheless, participants are allowed to, encouraged to update their SEP forecast until probably midmorning today. After that, so staff has to—has to cumulate all of that and create the documents that you see. So until about midmorning, a little, maybe late morning, it's okay to update, and I believe some people did update their forecast based on what we saw today.

CATARINA SARAIVA. Okay. And do you see—I mean, how are you, when you think about, you know, starting to think about the rate cuts next year or whenever they come, how do you, you know, how do you think about the economy we're in now kind of post-pandemic? Do you think that there's been significant structural shifts, and is that going to change how you look at a rate cut path?

CHAIR POWELL. The question of whether there have been fundamental structural shifts is, is really hard to know the answer and a very interesting one right now. The one that would affect—the one that comes to mind, though, is just the question of where the neutral rate of interest is. And so, for example, if it's risen, and I'm not saying that it has, but if it were to have risen, that would mean that, that interest rates would need to be a little bit higher to convey the same level of restriction. The thing is, we're not really going to know that. You know, people will be writing papers about that 10 years from now and still fighting about it. So it's just that it's going to be uncertain.

So we're going to be making policy in this, you know, difficult, uncertain, really unprecedented environment. Some—someone once said that you know the—you know the natural rate of interest by its works, and that's really right, but that's very difficult because policy operates with a lag. So that's one of the reasons why we slowed down this year. We started slowing down at this meeting last year, reducing the pace at which we were adding restriction. And, over the course of this year, we really slowed down a lot to give those lags time to work.

In terms of demand, has demand shifted more away from services into goods? There's—you can make a case for that, that the shift back into services has not been complete, and it doesn't look like it's ongoing, but I don't know if that's right. Maybe people just bought so much stuff that they temporarily don't want any more stuff. They haven't got anyplace to put it. [Laughter]

MICHELLE SMITH. Let's go to Jennifer.

JENNIFER SCHONBERGER. Thank you, Chair Powell. Jennifer Schonberger with Yahoo Finance. You said back in July that you needed to start cutting rates before getting to 2 percent inflation. As you mentioned, PCE inflation is now running at 3½ on core. On a six-month annual basis, core PCE is running at 2½ percent, though when you look at supercore and shelter, they are, of course, stickier. So when looking in the different components of the data, how much closer do you have to get to 2 percent before you consider cutting rates?

CHAIR POWELL. I mean, the reason you wouldn't wait to get to 2 percent to cut rates is that policy would be, it would be too late. I mean, you'd want to be reducing restriction on the economy well before 2 percent because—or before you get to 2 percent so you don't overshoot, if we think, think of restrictive policy as weighing on economic activity. You know, it takes—it takes a while for policy to get into the economy, affect economic activity, and affect inflation. So I can't give you a precise answer. But if you look at what's in the—in the SEP, and, you know, I think you'll see a reasonable estimate of the time lags and things like that that it would take.

JENNIFER SCHONBERGER. Do think below 3 percent would be reasonable?

CHAIR POWELL. I wouldn't want to—I wouldn't want to identify any one precise point, because I would be able to look back then and probably find out that it turned out not to be right. But we'll be looking at it and, and looking at the broad collection of factors.

MICHELLE SMITH. Let's go to Jean Yung.

JEAN YUNG. Hi, Chair Powell. Jean Yung with Market News. I wanted to go back to the stickiness-of-inflation question. Over the past couple of years, a lot of central bankers have talked about the more difficult last mile of getting inflation back down to 2 percent, yet it's also been surprising how fast inflation has come down this year. I'm curious, do you think something has changed in our understanding of inflation, or do you subscribe to this notion still? Or is it something different about the U.S. economy? Thank you.

CHAIR POWELL. I think—I think this. You know, we felt since the beginning that it would be a combination of two factors. The first factor is just the unwinding of, of what happened in the pandemic: the distortions of supply and demand. And the second thing would be our policy, which was weighing on aggregate demand and actually making it easier for the supply side to recover because of lower demand. We thought those two things were going to be necessary. Sorry, say your—say the last part of your question again.

JEAN YUNG. If there was something different about the U.S. economy.

CHAIR POWELL. Yeah. So it's not that—it may or may not be about "different," the U.S. economy being different. I think that this inflation was not the classic demand overload, pot-boiling-over, kind of inflation that we [typically] think about. It was a combination of very strong demand, without question, and unusual supply-side restrictions, both on the goods side but also on the labor side, because we had a—we had a participation shock. So this is just very unusual.

And, you know, we had the view—my colleagues and I broadly had the view—that we could get a lot of—you know, you had essentially a vertical supply curve, because you ran into the limits of, of capacity at very low levels, because there weren't workers and because people couldn't—the supply chains were all broken. So we, we had the view that you could come straight down that vertical supply curve to the extent demand [was] lowered, reduced. And, you know, something like that has happened. It happened so far. The question is, you know, once, once that part of it runs out—and we think it has a ways to run; we definitely think that the sort of supply chain and shortages side has some, some ways to run—does labor force participation have much more to run? It might. Immigration could help, but it may be that, at some point—at some point, you will run out of supply-side help, and then it gets down to demand, and it gets harder. That's, that's very possible. But to say with certainty that the last mile is going to be different, I'd be reluctant to, you know, to suggest that we have any certainty around that. We just don't know. I mean, inflation keeps coming down. The labor market keeps getting back into balance. And it's so far, so good—although we kind of assume that it will get harder from here. But so far, it hasn't.

MICHELLE SMITH. Okay. We'll go to Megan for the last question.

MEGAN CASSELLA. Hi, Chair Powell. Thanks for taking our questions. Megan Cassella with *Barron's*. I want to ask about the balance sheet given the Fed's focus now on proceeding carefully and considering rate cuts. And can you talk us through what the latest thinking is, and has there been any consideration of altering the pace of quantitative tightening at all?

CHAIR POWELL. We're, we're not talking about altering the pace of QT right now, just to get that out of the way.

So the balance sheet seems to be working pretty much as expected. What we've been seeing is, you know, that we're allowing runoff each month. That's adding up. I think we're down—we're close to 1.2 trillion [dollars]. That's showing up. The reverse repo facility [take-up] has been coming down quickly, and reserves have been either moving up or—as a result—or holding steady. At a certain point, you know, there won't be any more to come out of, or there'll be a level where [take-up at] the reverse repo facility levels out. And, at that point, reserves will start to come down.

You know, we still have—you know that we intend to reduce our securities holdings until we judge that the quantity of reserve balances has reached a level somewhat above that consistent with ample reserves, and we also intend to slow and then stop the decline in size of the balance sheet when reserve balances are somewhat above the level judged to be consistent with ample reserves. We're not at those levels, you know, with, with reserves close to 3.5 trillion [dollars]. We're not—we don't think we're at those [levels judged consistent with ample] reserves. There isn't a lot of evidence of that. We're watching it carefully. And, you know, so far—so far, it's working pretty much as expected, we think.

MEGAN CASSELLA. Do you anticipate adjusting that thinking at all by the time you're, you're considering or moving forward with rate cuts? Is that time to rethink, or are you still going to follow that thinking?

CHAIR POWELL. So I think they're, they're on independent tracks. You're asking, though, the question, I guess you're implying the question of can you continue with QT at such time—QT, which is a tightening action—at such time as policy is still tight? And the answer is, it depends on the reason. You know, if you're—if you're—if you're cutting rates because you're going back to normal, that's one thing, [and distinct from] if you're cutting them because the economy is really weak. So you can imagine, you'd have to know what the reason is to know whether it would be appropriate to do those two things at the same time.

MICHELLE SMITH. Thank you.

CHAIR POWELL. Thanks very much.

Transcript of Chair Powell's Press Conference
January 31, 2024

CHAIR POWELL. Good afternoon. My colleagues and I remain squarely focused on our dual mandate to promote maximum employment and stable prices for the American people. The economy has made good progress toward our dual-mandate objectives. Inflation has eased from its highs without a significant increase in unemployment. That's very good news. But inflation is still too high, ongoing progress in bringing it down is not assured, and the path forward is uncertain. I want to assure the American people that we're fully committed to returning inflation to our 2 percent goal. Restoring price stability is essential to achieve a sustained period of strong labor market conditions that benefit all.

Today, the FOMC decided to leave our policy interest rate unchanged and to continue to reduce our securities holdings. Over the past two years, we've significantly tightened the stance of monetary policy. Our strong actions have moved our policy rate well into restrictive territory, and we've been seeing the effects on economic activity and inflation. As labor market tightness has eased and progress on inflation has continued, the risks to achieving our employment and inflation goals are moving into better balance. I will have more to say about monetary policy—about monetary policy, after briefly reviewing economic developments.

Recent indicators suggest that economic activity has been expanding at a solid pace. GDP growth in the fourth quarter of last year came in at 3.3 percent. For 2023 as a whole, GDP expanded at 3.1 percent, bolstered by strong consumer demand as well as improving supply conditions. Activity in the housing sector was subdued over the past year, largely reflecting high mortgage rates. High interest rates also appear to have been weighing on business fixed investment.

The labor market remains tight, but supply and demand conditions continue to come into better balance. Over the past three months, payroll job gains averaged 165,000 jobs per month, a pace that is well below that seen a year ago but still strong. The unemployment rate remains low at 3.7 percent. Strong job creation has been accompanied by an increase in the supply of workers. The labor force participation rate has moved up, on balance, over the past year, particularly for individuals aged 25 to 54 years, and immigration has returned to pre-pandemic levels. Nominal wage growth has been easing, and job vacancies have declined. Although the jobs-to-workers gap has narrowed, labor demand still exceeds the supply of available workers.

Inflation has eased notably over the past year but remains above our longer-run goal of 2 percent. Total PCE prices rose 2.6 percent over the 12 months ending in December; excluding the volatile food and energy categories, core PCE prices rose 2.9 percent. The lower inflation readings over the second half of last year are welcome. But we will need to see continuing evidence to build confidence that inflation is moving down sustainably toward our goal. Longer-term inflation expectations appear to remain well anchored, as reflected in a broad range of surveys of households, businesses, and forecasters, as well as measures from financial markets.

The Fed's monetary policy actions are guided by our mandate to promote maximum employment and stable prices for the American people. My colleagues and I are acutely aware that high inflation imposes significant hardship, as it erodes purchasing power, especially for those least able to meet the higher costs of essentials like food, housing, and transportation. We're highly attentive to the risks that high inflation poses to both sides of our mandate, and we're strongly committed to returning inflation to our 2 percent objective.

Over the past two years, we have raised our policy rate by 5¼ percentage points, and we've decreased our securities holdings by more than $1.3 trillion. Our restrictive stance of monetary policy is putting downward pressure on economic activity and inflation. The Committee decided at today's meeting to maintain the target range for the federal funds rate at 5¼ to 5½ percent and to continue the process of significantly reducing our securities holdings.

We believe that our policy rate is likely at its peak for this tightening cycle and that, if the economy evolves broadly as expected, it will likely be appropriate to begin dialing back policy restraint at some point this year. But the economy has surprised forecasters in many ways since the pandemic, and ongoing progress toward our 2 percent inflation objective is not assured. The economic outlook is uncertain, and we remain highly attentive to inflation risks. We're prepared to maintain the current target range for the federal funds rate for longer if appropriate.

As labor market tightness has eased and progress on inflation has continued, the risks to achieving our employment and inflation goals are moving into better balance. We know that reducing policy restraint too soon or too much could result in a reversal of the progress we've seen on inflation and ultimately require even tighter policy to get inflation back to 2 percent. At the same time, reducing policy restraint too late or too little could unduly weaken economic activity and employment. In considering any adjustments to the target range for the federal funds rate, the Committee will carefully assess the incoming data, the evolving outlook, and the balance of risks. The Committee does not expect that it will be appropriate to reduce the target range until it has gained greater confidence that inflation is moving sustainably toward 2 percent. We will continue to make our decisions meeting by meeting.

We remain committed to bringing inflation back down to our 2 percent goal and to keeping longer-run—longer-term inflation expectations well anchored. Restoring price stability is essential to set the stage for achieving maximum employment and stable prices over the longer run.

To conclude: We understand that our actions affect communities, families, and businesses across the country. Everything we do is in service to our public mission. We at the Fed will do everything we can to achieve our maximum-employment and price-stability goals.

Thank you. I look forward to our questions.

MICHELLE SMITH. Jeanna.

JEANNA SMIALEK. Jeanna Smialek from the *New York Times.* Thanks for taking our questions. Obviously, in the statement and just in your remarks there, you note that you don't want to cut interest rates without greater confidence that inflation is coming—coming down fully. I wonder—what do you need to see at this point to gain that confidence? And as you make those decisions, how are you weighing recent strong growth in consumer spending data against the sort of solid inflation progress you've been seeing?

CHAIR POWELL. Sorry—say that last part again.

JEANNA SMIALEK. How are—how are you weighing the growth data and consumption data, which have been surprisingly strong, against inflation data?

CHAIR POWELL. Okay. So, what are we looking for to get greater confidence? Let me say that we have confidence. We're—we're looking for greater confidence that inflation is moving sustainably down to 2 percent. Implicitly, we do have confidence, and it has been increasing, but we want to get greater confidence. What do we want to see? We want to see more good data. It's not that we're looking for better data. It's—we're looking at continuation of the good data that we've been seeing, and a good example is inflation. So we have six months of good inflation data. The question really is, that six months of good inflation data—is it sending us a true signal that we are, in fact, on a path—a sustainable path down to 2 percent inflation? That's the question. And the answer will come from some more data that's also good data. It doesn't—it's not that the six-month data isn't—isn't low enough. It is. It's just a question of, can we take that with confidence that we're moving sustainably down to 2 percent? That's really what we're thinking about.

In terms of, of growth, we've had strong growth. I mean, if you take a step back, we've had strong growth—very strong growth [in real GDP] last year—going right into the fourth quarter. And yet we've had a very strong labor market, and we've had inflation coming down. So I think—whereas a year ago, we, we were thinking that we needed to see some softening in economic activity—that hasn't been the case. So I think we, we look at—we look at stronger growth. We don't look at it as a problem. I think, at this point, we want to see strong growth. We want to see a strong labor market. We're not looking for a weaker labor market. We're looking for inflation to continue to come down, as it has been coming down for the last six months.

JEANNA SMIALEK. And I'm sorry. If I could just follow up very quickly, the—when, when you say that you want to make sure that it's a true signal, is there anything that you're seeing in the data that makes you doubt that it's a true signal at this stage?

CHAIR POWELL. No, I think it's—I, I would say it, it seems—it seems to be the likely case that, that we will achieve that confidence, but we have to achieve it, and we haven't yet. And so—I mean, it's a good story. We have six months of good inflation [readings]. But you can—and you know this—you can look behind those numbers, and you can see that a lot of it's been coming from goods inflation, for example, and goods inflation running significantly negative. It's a reasonable assumption that, over time, goods inflation will flatten out—probably approximate zero. That would mean the services sectors would have to contribute more. So, in other words, what we care about is the aggregate number—not so much the composition. But we, we just need to see more. That's where we are, as a Committee. We need to see more evidence that sort of confirms what we think we're seeing and that tells us that we are on—gives us confidence that we're on, on a path to—a sustainable path down to 2 percent inflation.

MICHELLE SMITH. Nick.

NICK TIMIRAOS. Nick Timiraos of the *Wall Street Journal.* Chair Powell, it seems to me you raised rates rapidly over the last two years for two reasons. One was the risk of a wage–price spiral. Two, there were risks of inflation expectations becoming unanchored. This morning's ECI report for the fourth quarter shows private-sector payroll growth running at a sub–4 percent pace. Inflation expectations are very close to where they were before the inflation emergency of the last three years. And, given that you appear to have substantially cut off these two tail risks and that you've judged here today current policy as well into restrictive territory, what good reason is there to keep policy rates above 5 percent? Are you really going to learn more waiting six weeks versus three months from now that you have avoided those two risks?

CHAIR POWELL. So, as you know, almost every participant on the Committee does believe that it will be appropriate to reduce rates and for, for—partly for the reasons that you say. You know, we, we feel like inflation is coming down. Growth has been strong. The labor market is strong. We're—what we're trying to do is identify a place where we're really confident about inflation getting back down to 2 percent so that we can then begin the process of dialing back the restrictive level. So, overall, I think—I think people do believe—and, as you know, the median participant wrote down three rate cuts this year. But I think to get to that place where we feel comfortable starting the process, we need some confirmation that inflation is, in fact, coming down sustainably to 2 percent.

NICK TIMIRAOS. If I could ask differently: If, if you hold rates high as inflation moderates, as it—as it has been, target rates will exceed the prescriptions of the Taylor rule or its variants. What would be the reasoning for holding rates higher than the levels recommended by those rules in the current instance?

CHAIR POWELL. Well, I—look, I think, as you know, we consult the range of Taylor rules and, and non-Taylor kind of rules. We consult them regularly. They're in our, our Tealbook, and, and they're in all the materials that we look at. But, you know, I don't think we've ever been at a—at a place where we were—where we were setting policy by them. And there—depending on the rule, it will tell you different things. There are many different formulations. Another way to think about it is, implicitly, is—so, in theory, of course, real rates go up if—holding all else equal—as inflation comes down. But that doesn't mean we can mechanically adjust policy as real rates—sorry—as inflation comes down. It doesn't mean that at all, because, for one thing, we, we don't know—we, we look at more than just the fed funds rate. We look at—broadly—financial conditions.

But, in addition, we don't know with great confidence where the neutral rate of interest is at any given time. But that also doesn't mean that we wait around for—to see, you know, the economy turn down, because that would be too late. So we're really in a risk-management mode: of managing the risk—as I mentioned in my opening remarks—managing the risk that we move too soon and move too late. And I think to move, which is—which is where almost everyone on the Committee is—is in favor of, of moving rates down this year—but the timing of that is going to be linked to our gaining confidence that inflation is on a sustainable path down to 2 percent.

MICHELLE SMITH. Howard.

HOWARD SCHNEIDER. Hi. Thanks, Chair Powell. I'd like you to, to key in on the use of the word in, in the statement that inflation still "remains elevated." You've pledged to cut rates before inflation reached 2 percent. So that implies that there's some sort of intermediate step here on, on inflation and that a, a cut would be consequent with a change in the statement language that inflation "remains elevated." What's the step-down from there?

CHAIR POWELL. Yeah, I, I don't know that we've worked out the particulars—statement language and that kind of thing. I would just say, if you look at—you know, look at where, where 12-month inflation is, and it's, you know, it's still well above—core is 2.9 percent, for example—12-month—which is way down from where it was. Very, very positive development—very fast decline—and, and, you know, the, the case is likely that it will continue to come down. So, so that's where—that's where it is. But we're, you know, we're wanting to see, you know, more data.

HOWARD SCHNEIDER. So, if I—if I could follow up on that, the statement allows that you want greater confidence on inflation falling before you cut, but it doesn't mention the other side of the mandate—a slide in employment. Would a slide in employment also bring you to the point of, of cutting rates?

CHAIR POWELL. Yes. So let me say that we're not looking for that. That's not something we're looking for. But, yes, if you think about, you know—in, in the base case, the economy is performing well—the labor market remains strong. If we saw an unexpected weakening in, in—certainly in the labor market, that would certainly weigh on cutting sooner. Absolutely. And if we saw inflation being stickier or higher or those sorts of things—would argue for moving later. In the base case, though, where, where the economy is healthy and we have, you know, we have ongoing growth—solid growth—we have a strong labor market—we have inflation coming down—that's what people are writing their SEP [submissions] around. And in that case, what we're saying is, based on that, we think we can and should take advantage of that and, and be careful as we approach that question of when to begin to dial back restriction.

MICHELLE SMITH. Claire.

CLAIRE JONES. Claire Jones, *Financial Times.* Just to circle back to the "greater confidence" aspect of the statement, there's been a lot of unanimity in recent meetings. I'm just wondering, going forward, when it comes to all needing greater confidence, is there unanimity or, at least, consensus among FOMC members about what the threshold for that greater confidence is? And if not, could you maybe tell us a little bit about the discussion today on, you know, what the variations between FOMC members was on what constitutes enough confidence to cut rates and also if there was any variation on how quickly that "greater confidence" threshold could be reached? Thank you.

CHAIR POWELL. So we're not—we're not really at that stage. You know, we're—we're—there was no proposal to cut rates. Some people did, you know, talk about their view of the rate path. I would point you to the [December 2023] SEP as, as, you know, as good evidence of where people are, although it is—it is [now] one [FOMC meeting] cycle later. So, you know, we're not—we're not at a place of, of really working out those kinds of details, because we weren't actively considering, you know, a—moving, moving the federal funds rate down. I will say, there is a—there is a wide disparity—a healthy disparity—of views, and you see that in public, public statements, in the minutes, and the transcripts when they're released every five years. So we do have a healthy set of differences, and I think that's actually essential for making good policy. We're also able to reach agreement, generally, because we listen to each other—

we, we compromise. And even though not everybody loves what we do, they're able to—for the most part—able to join in. To me, that's a well-functioning public institution.

MICHELLE SMITH. Rachel.

RACHEL SIEGEL. Hi, Chair Powell. Rachel Siegel from the *Washington Post.* Thanks for taking our questions. So, over the past few years, there have been all these real-time indicators that helped us gain a sharper understanding of where the economy was, like OpenTable data or office attendance. You've talked about vacancies in the past. And I'm wondering, at the start of this year, what might be on that dashboard for you that's giving you the clearest picture of the economy—including on rents—if you could touch on that.

CHAIR POWELL. Including?

RACHEL SIEGEL. Rent. Rent costs.

CHAIR POWELL. Yeah. Well, so we're not—you know, it's not the pandemic, so we can actually rely on more, more traditional forms. People are working. They're getting wages, and, and the economy has largely reopened and is broadly normalizing, as you see. So I wouldn't say we're looking at that, that sort of more innovative data as much. You know, you point to rents. So, of course, we follow the, the components of inflation very carefully. Which would be: Goods inflation—I talked about that a little bit; you mentioned housing inflation. So the question is, when will these lower market rents find their way into measured rents, as measured, measured in PCE inflation?

And we think that's coming, and we know it's coming. It's just a question of when and, and how big it'll be. So—but that's in, in everyone's forecast, I would say. So that will—that will help. But at the same time, we think goods inflation will probably—it's been giving a lot of disinflation to the effort—and probably that declines over time, but it may well have some, some more time to run. You know, these—the supply chains are not perfectly back to where they were. In addition, it takes time for the, the healing process to get into prices. So there may be still a tailwind. We'll find out with, with that. So we look at the things that relate to our mandate very carefully, and—as you would imagine.

RACHEL SIEGEL. I guess, just as a quick follow-up—do you feel comfortable at this point saying the economy has reached a soft landing, or is that part of looking for more confidence?

CHAIR POWELL. No, I wouldn't—I wouldn't say we've achieved that. And I, I think we have—we have a ways to go. Inflation is still—you know, core inflation is still well above target on a 12-month basis. Twelve months is our, our target, certainly. I'm encouraged, and we're encouraged by the progress. But, you know, we're, we're not—we're not declaring victory at all at this point. We think we have a ways to go.

MICHELLE SMITH. Steve.

STEVE LIESMAN. Thank you, Mr. Chairman. You've said that you would know the neutral rate by its works. So I'm wondering what you could tell me—how do you believe the neutral rate is working or telling you right now that growth is stronger? In other words, how much is the economy really being restrained right now by the current funds rate? And how much restraint does it really need, additionally, if inflation is still coming down?

CHAIR POWELL. So it's—I think you, you do see in the interest-sensitive parts of the economy—you do see, for example, housing. You see the effects. You do. Your, your second question, though, really, I think, is important, and that is, a lot of this has come through—a lot of the disinflationary process has come through the healing of supply chains and also of the labor market. So you've seen the—you know, that other set of factors is really different from other cycles and has brought that working with tighter, tighter policy, which has enabled the supply side to recover—I think is that, that mixture has been behind what has enabled this. So, no—we really do think that we're having an effect broadly across the economy. I would point to the interest-sensitive parts of the economy as well as spending, generally. But it's a—it's a joint story. It's a complicated story.

STEVE LIESMAN. But, but how much restraint are you actually imparting to the economy, would you say, relative to the neutral rate?

CHAIR POWELL. It's—so I think it's, it's—of course, you know that it's not something you can identify with any precision. But if you—a standard approach would be to take the nominal rate—5.3 percent, let's say—and subtract sort of a, a forward measure of inflation. If you do that—and there are many, many ways to calculate the neutral rate—but that's one I like to do. And, you know, you're going to get to something that is materially above mainstream estimates of neutrality—of the neutral rate—you will. And—but at the same time, you look at the economy, and you say, "This is an economy that grew 3.1 percent last year." And, and you say, "What does that tell you about the neutral rate?" What's happening, though, is, the supply side has been recovering in the middle of this. So that, that won't go on forever. So a lot of the growth we're seeing is not—is—it isn't just a tug of war between, between interest rates and demand. You're getting, you know, more activity because of the—of labor market healing and supply chains healing. So I think the question is, when that peters out, I think the, the, you know, the, the restriction will show up probably more, more sharply.

MICHELLE SMITH. Rich.

RICH MILLER. Thank you—sorry. Thanks for taking the question, Mr. Chairman. You mentioned earlier we're not seeking a weaker labor market, I think you, you said. Can you talk a little bit more about that? Do you—do you think the labor market now is back to quote, unquote, "normal" and that the—we can achieve the inflation target without wage gains coming back down to what they were pre-pandemic? Even with today's ECI levels, they were still above those pre-pandemic levels.

CHAIR POWELL. I, I think the labor market by many measures is at or nearing normal—but not totally back to normal. And you pointed to one or more of them. So I think, you know, job openings are not quite back to where they were. Wages—wage increases, rather, are not quite back to where they—to where they would need to be in the longer run. I, I would look at it this way, though. The, the economy is broadly normalizing, and so is the labor market. And that process will probably take some time. So wage setting is something that happens—it's, it's—you know, probably will take a couple of years to get all the way back. And that's okay. That's okay. But we do see—you saw today's ECI reading—you know, the evidence is that, that wage increases are still at a healthy level—very healthy level—but they're gradually moving back to levels that would be more associated—given, given assumptions about productivity, are more typically associated with 2 percent inflation. It's, it's an ongoing process—a healthy one—and, and, you know, I think we're, we're moving in the right direction.

RICH MILLER. So that process can continue without a weakening of the labor market, basically, you're saying?

CHAIR POWELL. I think the, the labor market is—it—I don't know if I'd—it's rebalancing. Clearly, that the—there was a fairly severe imbalance between demand for workers and supply at the beginning of the pandemic. So we lost several million workers at the beginning of the pandemic from people dropping out of the labor force. And then when the economy reopened—you remember 2021—you had a severe labor shortage, and it was just—it was everywhere—panic on the part of businesses—couldn't, couldn't find people. So, what's happened is—we expected labor—the labor supply—labor market to come back quickly, and it didn't. And 2022 was a disappointing year, and, you know, we were kind of thinking, "Well, maybe we won't get it back." And then 2023, we did, as you know—so labor force participation came back strongly in '23, and so did immigration. Immigration came to a halt during the pandemic.

So—and so those two forces have significantly lowered the temperature in the labor market to what is still a very strong labor market. It's still a good labor market for wages and for finding a job, but it's getting back into balance, and that's what we want to see. And, you know, one great way to look at that is what's happening with, with wage increases. And you see it now across the, the major things that we—that we track. It isn't every quarter, but, overall, there's a clear trend—still at high levels, but back down to where—what would be consistent with, with where we were before the pandemic and with 2 percent inflation.

MICHELLE SMITH. Chris.

CHRISTOPHER RUGABER. Hi, Chris Rugaber at Associated Press. Thank you. I wanted to follow up on Rich's question. It sounded like you suggested that you're not worried about faster growth so much—so wanted to see if you're seeing anything that suggests that inflation could reaccelerate from here. And it sounds like you're saying you're not worried that solid growth from here on out poses any risk to inflation. Thank you.

CHAIR POWELL. No, I think that that is a risk—the risk that inflation would, would reaccelerate. I think the, the greater risk is that it would—that it would stabilize at a level meaningfully above 2 percent. That's, that's, to me, more likely. Of course, if—if inflation were to surprise by moving back up, that would—we would have to respond to that, and that would—

that would be a surprise at this point. But I have to tell you, that's why we keep our options open here and why we're not, you know, rushing. So I, I think both of those are risks, but I think the more likely risk is the one that I mentioned, which is, you've had six good months—very good months—but what, what's really going to "shake out" here? You know, where—what will—when we look back, what will we see? Will, will inflation have dipped and then come back up? Are the last six months flattered by factors that are—that are one-off factors that won't repeat themselves? We don't think so. We don't—you know, that's not what we think, but that's the question we are asking. We have to ask [that], and we want to get comfort on that.

CHRISTOPHER RUGABER. And just one quick follow-up—Governor Waller had mentioned the revisions that are coming on February 9th for the CPI data. Is that something you're watching as well? And if, if we see those revisions fairly minor, is that going to give you more confidence where things are going?

CHAIR POWELL. We'll just have to see. Yeah. We'll—we look at those. Last year was a—was a, a surprise.

MICHELLE SMITH. Mike.

MICHAEL MCKEE. Michael McKee, Bloomberg Radio and Television. If you don't want to use the term "soft landing," would you say, at least, that, from your point of view now, the other scenario of a hard landing caused by the Fed is off the table or the risks have diminished very much? And you mentioned below–2 percent inflation for—on a three-month basis, core PCE has been running at 1½ percent. And there are those on Wall Street who think that if you maintain the level of restriction you have right now, you could end up with inflation running below your target. How do you see that?

CHAIR POWELL. So, how to—your first question—how to describe where we are? So I guess I would just say this—executive summary would be that growth is solid to strong over the course of last year. The labor market—3.7 percent unemployment indicates that the labor market is strong. We've had just about two years now of, of unemployment under 4 percent. That hasn't happened in 50 years. So it's a good labor market. And we've seen inflation come down. We've talked about that. So we've got six months of good inflation data and an expectation that there's more to come. So this is a—this is a good situation. Let's be honest. This is a—this is a good economy.

But what's the outlook? That's looking in the rearview—the outlook—we do expect growth to moderate. Of course, we have expected it for some time, and it hasn't happened, but we do expect that it will moderate as supply chain and labor market normalization runs its course. The labor market is rebalancing, as, as I mentioned. Job creation has slowed. The base of job growth has narrowed. And, of course, 12-month inflation is, is above target and getting, you know, getting down closer to target. It's not guaranteed, but we do seem to be getting on track for that. So those are the risks and, and questions we have to answer. But, overall, this is a pretty good picture. It, it is a good picture. Your second question was—sorry.

MICHAEL MCKEE. Could you get inflation that is below target—end up with inflation below target, and you have to do something about that?

CHAIR POWELL. So we—the thing is, we're not looking for inflation to tap the 2 percent base once. We're looking for it to settle out over time at 2 percent. And the same thing is true if we have a month or two of lower—and we have that now—of, of inflation that's annualized at a—at a lower level—that wouldn't be good. We're not—you know, we're not looking to have inflation anchor below 2 percent. We're looking to have it anchor at 2 percent.

So if we do face those circumstances, then we'll have to deal with that. I think—I think as of now, you know, the, the question, which—we want to take advantage of this situation and finish the job on inflation while keeping the labor market strong.

MICHELLE SMITH. Edward.

EDWARD LAWRENCE. Edward Lawrence from Fox Business. Thank you, Mr. Chairman, for taking this. So, as I've—as I've heard from some District Fed presidents, is it, in your view, a little premature to think that rate cuts are right around the corner? And then when we do see that first rate cut, is that—should we interpret that as the beginning of a rate-cut cycle, or is it a one-off?

CHAIR POWELL. So I'll point you to that language on your first question. We, we included that language in the statement to signal clearly that—with strong growth, strong labor market, inflation coming down—the Committee intends to move carefully as we consider when to begin to dial back the restrictive stance that we have in place. So if you take that to the current context—current context, we're going to be data dependent. We're going to be looking at this meeting by meeting. Based on the meeting today, I would tell you that I don't think it's likely that the Committee will reach a level of confidence by the time of the March meeting to identify March as the time to do that. But that's, that's to be seen. So I wouldn't call—you know, when you say—when you ask me about "in the near term," I'm hearing that as March. I would say I don't think that's—that's, that's probably not the most likely case or what we would call the base case. And your second question is—

EDWARD LAWRENCE. On, on the—is this the start of a—when we see a cut, is it the start of a cutting cycle, or is it—could it just be a one-off?

CHAIR POWELL. You know, that's going to depend on the data. The whole thing is, this is going to depend on the data. We're going to be looking at the economic data as it affects the outlook and the balance of risks. And we're going to make our decisions based on that. And it could wind up—you know, we'll, we'll have another SEP at the March meeting, and, and people will write down what they think. But, in the end, it's really going to depend on how the economy evolves. We talked about, there are risks that would cause us to go slower—for example, stronger inflation—more, more persistent inflation. There are risks that would cause us to—if they happen—that would cause us to go faster or—and sooner. And that would be a weakening in the labor market or, for that matter, very, very persuasive lower inflation. Those are the kinds of things. So we're just—we're just going to be reacting to the data. That's the—that's really the only way we can do this.

MICHELLE SMITH. Victoria.

VICTORIA GUIDA. Hi. Victoria Guida with Politico. Could you talk a little bit more about productivity growth? You know, you've mentioned multiple times about, you know, the level of wage growth that's consistent with 2 percent inflation. We've obviously seen, you know—you were talking about ECI this morning, in which it's cooled a little bit but still sort of above what you wanted to see. Growth has been very strong. How much of those numbers do you attribute to productivity? And do you see that productivity as sort of just temporary because of the factors—the labor and supply chain factors you were talking about—or do you think that productivity growth will, will fade over time?

CHAIR POWELL. So this is a really interesting question. And I think—my, my own view is—I think if you look, look back to the pandemic, you, you saw a spike in productivity as workers were laid off, and, and activity didn't decline as fast. And then you saw a deep trough of productivity. And then, over the last—you saw high productivity last year, in '23. I think we're, we're basically in the throes of getting through the pandemic economy. And the question will be, what, what is it that has changed the—you know, the productivity tends to be based on, you know, fundamental aspects of our economy. Is there—is there a case—will it be the case that we come out of this more productive on a sustained basis? And I don't know. I don't know. What would it take? It would take—you know, people talk about AI, but I would—my guess is that we may shake out and be back where we were, because I don't—I'm not sure I see—work from home doesn't seem like it's a big productivity increase. Or AI, artificial intelligence—generative it may be, but probably not in the short run—probably, maybe in the longer run. So I'm not—I'm not seeing why it would, but, you know, right—you know, right now I would say that productivity is kind of what falls out of the, the broader forces that are driving people in and out of the labor force and, and activity returning and supply chains getting fixed.

VICTORIA GUIDA. Right. So would that be behind why we've seen such strong growth, but we've also seen inflation fall—that maybe there's just a higher level of productivity?

CHAIR POWELL. That's one way to look at it. Yeah.

MICHELLE SMITH. Nancy.

NANCY MARSHALL-GENZER. Hi, Chair Powell. Nancy Marshall-Genzer with Marketplace. I want to ask a little bit more about housing. I'm wondering—how closely are you watching rent and housing prices as you evaluate whether and when to cut rates? And it seems like housing prices are not coming down as quickly as you expected.

CHAIR POWELL. So when we think about, you know—our, our statutory goals are maximum employment and price stability, and that's what we're targeting. We're not targeting housing price inflation, the cost of housing, or any of those things. Those are very important things for people's lives. But they're not—you know, those are not the things we're targeting. We're also well aware that when we cut rates at the beginning of the pandemic, for example, the housing, housing industry was helped more than any other industry. And when we raise rates, the housing industry can be hurt, because it's a very interest-sensitive sector.

On top of that, we have longer-run problems with the availability of housing. You know, we have a, a built-up set of cities, and, and, you know, people are moving further and further out. So there's—there hasn't been enough housing built. And these are not—these are not things that we have any tools to address. But, you know, where it comes into play very specifically in our work is inflation, which is a combination. It's, it's really rental inflation. You're taking owners' equivalent rent and then actual rent paid by tenants. And you're, you're running that through the CPI calculation. Or the PCE [inflation] calculation—the one we look at. And what that's telling you is that market rents are increasing at a much lower rate or even being flat and that that will show up in inflation over time. It has to as long as that remains the case.

NANCY MARSHALL-GENZER. And just real quick—what is your response to the letter that was sent to you by some members of Congress asking the Fed to lower interest rates to make housing more affordable?

CHAIR POWELL. My response is what I started with, which is that our, our job—the job Congress has given us is price stability and maximum employment. Price stability is absolutely essential for people's lives, most importantly for—well, not most importantly—most, mostly for people at the lower end of the income spectrum who are living at the edges—at the margins. And so someone—for someone like that, high inflation in the—in the necessities of life—right away, you're in trouble, whereas even middle-class people have some, you know, some scope to absorb higher costs. So we have to get—it's our job. It's what society has asked us to do, is to get inflation down, and the tools that we use to do it are interest rates. So that's how we think about that.

MICHELLE SMITH. Courtenay.

COURTENAY BROWN. Courtenay Brown from Axios. Can you give us some insight into whether the Committee discussed the possibility of slowing balance sheet runoff in the months ahead?

CHAIR POWELL. Yes. So I would start by saying that balance sheet runoff so far has gone very well. And as the process has continued, you know, we're getting to that time where questions are beginning to come into greater focus about the pace of runoff and all that. So at this meeting, we did have some discussion of the balance sheet, and we're planning to begin in-depth discussions of balance sheet issues at our next meeting in March. So those, those questions are all coming into scope now, and we're focusing on them. But we're, we're at the beginning of that process, I would say.

COURTENAY BROWN. Quick follow-up—is it the case that the Fed would decide to lower rates and make adjustments to the balance sheet runoff in tandem?

CHAIR POWELL. Yes, we do—we see those as independent tools. And so they don't—for example, if you're—if you're normalizing policy, you might be reducing rates but continuing to run off the balance sheet. In both cases, that's normalization, but from a strict monetary policy standpoint, you could say we're loosening along with tightening. So that, that could happen. It's not something we're planning or thinking about, but right now, we're thinking about getting to a place where—we're going to see the balance sheet runoff to continue. We're watching it carefully, and, as I said, we'll—we'll be looking into that as a Committee starting in March.

COURTENAY BROWN. Thanks.

MICHELLE SMITH. Simon.

SIMON RABINOVITCH. Simon Rabinovitch with the *Economist.* Thank you, Chair Powell. You've mentioned six good months of inflation data, but that not being enough to build up confidence. Based on your previous response that your base case is you probably wouldn't start easing yet in March, the implication is that eight good months might not be enough, either. Roughly how many months do you think you might need of, of good inflation data to be—to be confident?

CHAIR POWELL. I'm, I'm not in a position to put a number on it. I'm just going to say—and it's not that we don't have any confidence. We, we have growing confidence, but not to the point where we—where we feel like—it's a highly consequential decision to start the process of, of dialing back on restriction. And we want to get that right, and we feel like the strong economy, strong labor market, inflation coming down—it gives us the ability to do that. We think that's the best way we can serve the public, because, ultimately, we, we've made a lot of progress on inflation. We just want to make sure that we do get the job done in a sustainable way. That's how we're thinking about it. In terms of when that'll be, you know, that, that'll all come out of our communications, and, you know, we won't—we won't keep that a secret.

MICHELLE SMITH. Evan.

EVAN RYSER. Hi, Chair Powell. Evan Ryser with MNI Market News. Can you explain a little bit more on what you're considering when tapering QT? Do you need to see the overnight reverse repo facility all the way down to zero, or is it something that you can start with a couple hundred billion dollars there?

CHAIR POWELL. Not a decision that we've made, but I, I wouldn't think we'd, we'd be—we wouldn't be taking a position that it's got to go to zero. I mean, if it—if it were to stabilize at a different level—but that's, that's not a decision that we've made. That's, that's what we'll be talking about at the March meeting. A whole range of issues will be briefed up, and the Committee will get into—get into all of the issues that will be arising over the course of the next, let's say, year or so.

MICHELLE SMITH. Greg.

GREG ROBB. Thanks. Greg Robb from MarketWatch. Chair Powell, I want to change gears a little bit. In the presidential primary campaign that's been going on for the last nine months or so, your name has come up often, and many Republican candidates had said that they probably wouldn't want to give you a third term. So I wanted to give you a chance to talk about that. Do you want another term—you've had—on the Fed? What, what's your stance on that?

CHAIR POWELL. I don't have a stance on that. It's not something I'm focused on. [We're] focused on doing our jobs. We have—this year is going to be a highly consequential year for, for the Fed and for monetary policy. And we're, all of us, very buckled down, focused on doing our jobs.

MICHELLE SMITH. Jennifer.

JENNIFER SCHONBERGER. Thank you, Chair Powell. Jennifer Schonberger with Yahoo Finance. As you mentioned, core PCE [inflation] has been running at 1.9 percent over the past six months. And you guys are actually expecting core inflation higher this year, at 2.4 percent, compared to that six-month measure. Given that forecast and that the median is for three rate cuts this year, what happens if inflation stays where it's been over the last six months for the next six months?

CHAIR POWELL. So I—you know, we're going to do—we'll update our, our inflation forecasts at the next meeting. You referred to the December meeting. That's, that's, you know, three months old [by March], so it might be lower now, given the data we've gotten. So, look, as I mentioned, we're going to be reacting to the data. If, if we get—if we get very strong inflation data and it, it kicks back up, then it'll—then we'll go slower or later or both. If we got really good inflation data soon, that would matter for both the—that, that would tell us that, that we could go sooner and perhaps go faster. So we're just going to be—but, of course, we'll weigh that with all the other factors. We're setting policy based on the totality of, of the data.

JENNIFER SCHONBERGER. But just to follow—if inflation stays where it is currently, that would probably mean that the real interest rate becomes more restrictive. Would that mean you'd have to trim more, perhaps, than you already have factored in?

CHAIR POWELL. Well, I think if we—if we came to the view that, that inflation were—that the six-month inflation numbers, which are very close to 2 [percent], were, in "PCE world"—if we came to—if that's—if we thought that is really where we're going to be, then, yes, our policy would be in a different place. It would. But, you know, that's the whole point is, we're trying to get comfortable and gain confidence that that is where—that inflation is on a sustainable path down to 2 percent or toward 2 percent.

MICHELLE SMITH. Daniel.

DANIEL AVIS. Hi, Chair Powell. Daniel Avis, Agence France-Presse. I just wondered if I could get your comment on the recent consumer confidence data. It seems to suggest that consumers are sort of moving towards a much more optimistic view of the economy. I just wonder—is it fair to say that they're moving towards where the Fed appears to have been in recent months? And, you know, do you think that inflation and falling inflation perhaps has played a role in that? And what challenges do you see, going forward? Thank you.

CHAIR POWELL. Yeah, so it's been—it's been interesting that confidence surveys have been weak, at a time when unemployment has been low—very low, historically low—for a couple of years. And—but, nonetheless, that's been the case. And we've asked ourselves why that is. And, you know, one obvious answer—we don't pretend to have perfect wisdom on this—is—but one obvious answer is that the *price level* is high. So prices went up much more than 2 percent for year—per year for a couple of years. And people are going to the store, and they're paying much more for the basics of life than they were two years ago—three years ago. And they're not happy about it. And it's fine that inflation is coming down, but the price—the prices they're paying are still high.

So that, that is what—that, that has to be some part of why people are unhappy. And they're, they're right to be unhappy. You know, this is why we need to keep price stability. It's why we need to do our jobs—so that people don't have to deal with things like this.

In terms of [surveys]—you're right. In, in recent, recent surveys, a couple of—you've seen a couple of significant increases in, in consumer confidence or, or happiness with the economy. I guess that's a good thing. That can—that can support spending—can support economic activity. There's some evidence of that. But it is—it is a fact that we have seen, you know, a meaningful increase. I think levels of confidence are still maybe not as high as they've been at various times. But it's—they certainly have come up.

MICHELLE SMITH. Bryan.

BRYAN MENA. Thank you for taking our questions. Bryan Mena, CNN Business. Committee members have said they'd like to meet with business leaders and stakeholders in person to learn more about the economy in real time, given that some data is subject to large revisions, the issue of seasonal adjustments being thrown off balance, and many readings of the economy being quarterly. So did any members say they've learned anything not reflected in the data? Or have you yourself learned anything through anecdotal evidence that hasn't been captured in the data yet?

CHAIR POWELL. Well, yes. I'm, I'm a big believer that—yes. So we, we do meet with outside groups who come from all different parts of the economy. And I always feel like you—I mean, I spent most of my life in the private sector looking at companies—individual companies—individual management teams—and then building out from that. And so, starting with GDP data is—and working into what's actually affecting people's lives is—is challenging. It's very hard. So I, I really like anecdotal data. In addition, as you know, the 12 Reserve Banks have really the best network of anyone. In all their Districts, they're talking to, you know, not just the business community, but the educational, medical, all, all—you know, nonprofit community. They have arms into all of that. And so when they come back—that's what goes into the Beige Book. But they come back, and what each Reserve Bank president does is, during the outlook go-around, they'll say, "In my District . . ." And they'll talk about 100 conversations they—not—they won't talk—they, they will give you input, based on 100 conversations that they've had with people of all different walks. And it's—I personally find it very helpful in understanding what's going on. And also, I think you hear things before they show up in the data sometimes.

BRYAN MENA. Did any of them—did any of them notice slowing economy based on what they've heard from, like, their District?

CHAIR POWELL. Yes. I mean, if you—if you look back at the last—not this Beige Book, but the one before, it was more—there was a lot of "slower activity." I think that, that what you're hearing now is, is, things are picking up a bit. You're hearing—not, not in every District and not every, every person that we talk to, but you're—overall, it feels like you're hearing things picking up at the margin. So that's what comes through.

MICHELLE SMITH. Let's go to Jeff Cox for the last question.

JEFF COX. Thank you, sir. Jeff Cox from CNBC.com. Just kind of looking to put it all together: You talked about basically the, the economy looking strong with 3.3 percent annualized growth in the fourth quarter. Does the strength of the economy speak more loudly to you now than any inflation threat might? That, you know—you're in a position, in other words, to keep rates elevated as long as the economy stays strong, and you're more—you're more tilted towards that. And also, perhaps, are you worried at all that the economy is maybe a little too strong right now and that inflation could come back at some point?

CHAIR POWELL. I'm not so worried about that. You know, it's—again, we've had inflation come down without a slow economy and without, you know, important increases in, in unemployment, and there's no reason why we should want to get in the way of that process, if it's going to continue. So I, I am—you know, I think—I think declining inflation—continued declines in inflation are, are really the main thing we're looking at. Of course, we want the labor market to remain strong, too.

We don't have a growth mandate. We've got a, a maximum-employment mandate and a, a price-stability mandate, and those are the two things we look at. Growth only matters to the extent it influences our achievement of those two—of those two mandates.

Thank you very much.

Ameren, Exelon shares fall after Illinois regulators reject grid plans

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By Allison Good
Platts

Shares of Ameren Corp. and Exelon Corp. each dropped more than 7% on Dec. 14 after Illinois regulators rejected multiyear grid plan proposals by their utility subsidiaries and authorized lower-than-expected equity returns beginning in January 2024.

The Illinois Commerce Commission determined the four-year electric distribution grid plans proposed by Ameren Illinois Co. and Commonwealth Edison Co. did not adequately describe community benefits, transparency, affordability or cost-effectiveness and did not comply with the state's Climate and Equitable Jobs Act (CEJA) of 2021.

"The Commission's decisions today protect Illinois ratepayers and the goals CEJA created. Illinois' utilities are specifically required to consider affordability and cost-effectiveness so that customers are not unfairly asked to shoulder undue costs tied to the state’s energy transition," ICC Chairman Doug Scott said in a statement. "While we are not yet at the finish line, compliant plans from the state's largest utilities will help lead us to an energy transition that works for all Illinoisans."

The law requires Illinois to transition to 50% renewable energy by 2040 and 100% clean energy by 2050 through reducing emissions and supporting electrification.

The commission also authorized an 8.72% return on equity (ROE) for Ameren Illinois (Docket No. D-23-0082) and an 8.91% ROE for Commonwealth Edison (ComEd) (Docket No. D-23-0055), a substantial decrease from the administrative law judge's recommended 9.24% ROE for Ameren Illinois and 9.28% ROE for ComEd. Both utilities originally asked for a 10.50% ROE.

"We can say at this time that we are very disappointed with the outcome," ComEd said in a Dec. 15 email. "That said, we remain committed to working with all stakeholders, including our regulators, to deliver a cleaner, more equitable, and brighter energy future for the northern Illinois communities we're privileged to serve."

Ameren did not immediately respond to requests for comment.

Both companies' stock prices continued to decline Dec. 15. In midday trading, Ameren shares were down about 3.5%, hovering below $72, and Exelon shares were down about 5%, trading below $36, both on above-average volume.

Unexpected regulatory decisions

Industry analysts told investors that the rulings were worse than anticipated.

"Even though we believe most investors' expectations were significantly dampened by the mid-November final orders in the Illinois gas utility rate cases, from our conversations, investor outlooks had coalesced around the 9.3% to 9.4% level [for ROE]," analysts at BMO wrote. "Which, given the sensitivity of [approximately 4 cents of earnings per share] per every 50 [basis points] change in ROE for both companies, in our opinion, could have resulted in a de-risking event."

"We expect a disproportionate effect on 2024 earnings for each company," they continued.

The utilities have three months to refile their grid plans, but KeyBanc analysts still anticipate a "messy and contentious" process with an "uncertain" timeline. "We believe that it will be difficult for Ameren, as well as its peer, to maintain their status as premium utilities," the analysts said.

Wells Fargo analysts agreed that the grid plan rejections jeopardize Ameren's and Exelon's targeted earnings per share compound annual growth rates and told clients they "now view [Illinois] as one of the worst regulatory jurisdictions in the US."

None of the analysts faulted the companies' management.

"We don't see this as a management issue — both teams have been good operators and worked through the case process to a manageable proposed order. ... the ICC is simply sending a negative message to investors," Guggenheim analysts wrote.

During a third-quarter earnings call on Nov. 9, Ameren President and CEO Martin Lyons said the company was hopeful the ICC would "reach a more constructive and fair outcome" given that the administrative law judge's calculations used "inappropriate data points."

Exelon CEO Calvin Butler similarly criticized the law judge's decision during a Nov. 2 earnings call.

"The [proposed] order does not recognize a fair cost of financing that investment," Butler emphasized. "It provides a return on equity that is well below the national average. It does not recognize the significant investment we have made in our pension which supports ComEd's employees and has saved customers almost $1 billion to date with its returns and continues to generate savings for our customers, and it does not allow for a prudent capitalization of the business."

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Report

Greenhouse Gas Emissions Reduction Targets and Market-based Policies

Updated September 05, 2023 | Laura Shields

Related Topic: **Energy**

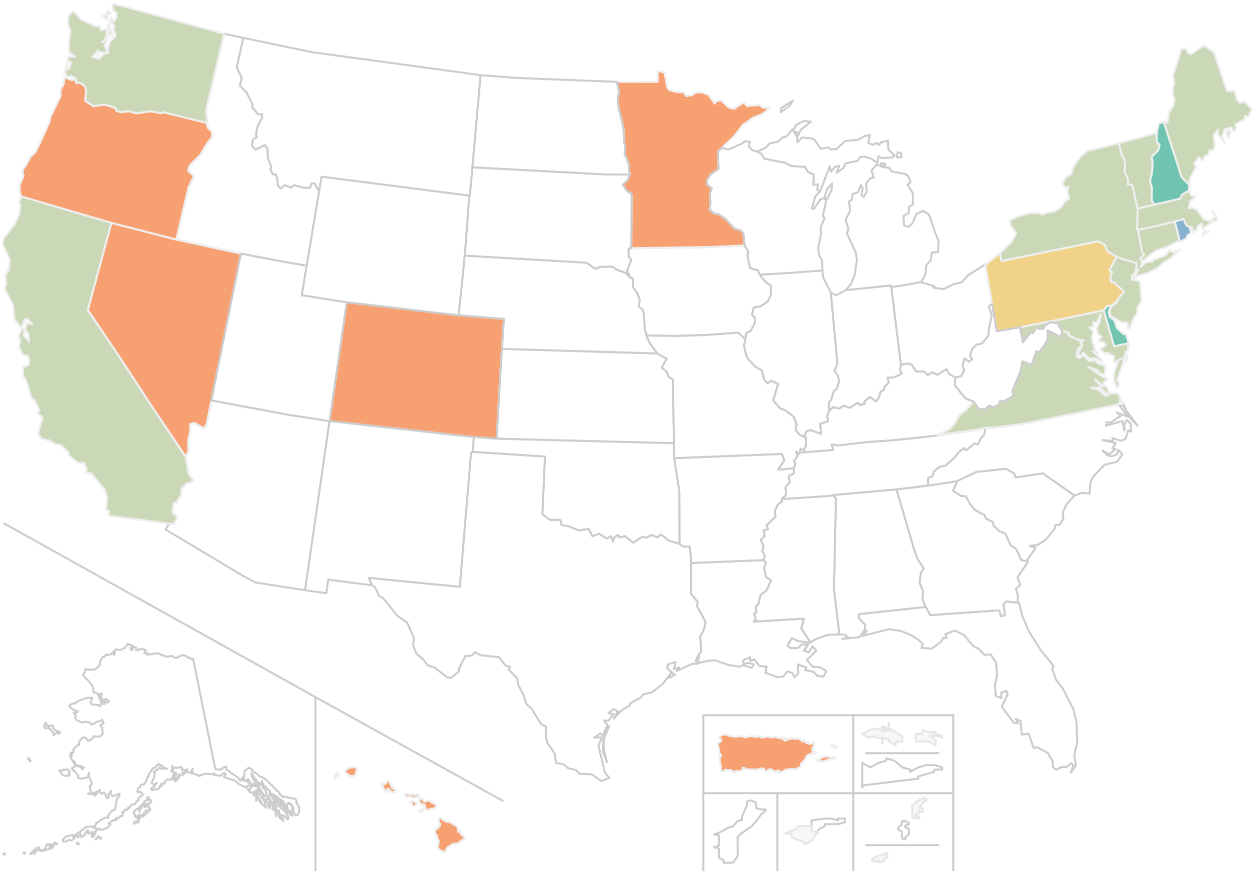
Introduction

States have implemented a variety of policies aimed at mitigating greenhouse gas (GHG) emissions. At least 16 states and Puerto Rico have enacted legislation establishing GHG emissions reduction requirements, with more requiring state agencies to report or inventory GHG emissions. Other states, such as New Mexico, North Carolina and Pennsylvania have recently committed to statewide GHG reduction goals through executive action but do not currently have binding statutory targets.

Several states have also implemented carbon pricing policies either independently or through regional agreements. California and Washington are employing a multisector GHG cap-and-trade program, and several Northeast and Middle Atlantic states are participating in the Regional Greenhouse Gas Initiative (RGGI), the first binding cap-and-trade program aimed at reducing GHG emissions from the power sector. Many of these same states also participate in the Transportation and Climate Initiative (TCI), which is committed to developing a cap-and-invest program aimed and reducing transportation sector emissions.

Many states have multiple policies in place, as shown in the map below. Several states have binding statutory requirements to reduce statewide emissions and complete a statewide inventory measuring emissions. Several Northeastern states participate in both the RGGI and TCI, addressing the two highest-emitting sectors of the U.S. economy: power and transportation. Additionally, multiple states have implemented statutory GHG reduction and reporting requirements, as well as a carbon pricing policy. While not addressed here, 30 states have renewable or clean electricity standards, which require that a percentage of electricity sold by utilities comes from renewable sources. Several states have recently increased their standards to require 100% renewable or zero-emissions electricity by midcentury.

States with Comprehensive Greenhouse Gas Reduction Policies



☐ States with no Reduction/ Reporting Requirements or Market-based Policy

🟩 Statutory Reduction and Reporting Requirements + Market-based Policy

🟦 Statutory Reduction Requirements + Market-based Policy

🟨 Statutory Reporting Requirements + Market-based Policy

🟧 Statutory Reduction and Reporting Requirements with no Market-based Policy

🟩 Participants in RGGI and TCI with no Statutory Reduction or Reporting Requirements

Reduction/Reporting Requirements

Maine was the first state to enact legislation setting specific GHG reduction targets in 2003, followed by California in 2006. Since then, several other states have enacted statutory targets, with Virginia being the most recent. Of the 16 states that have enacted GHG reduction targets, seven did so from 2007 through 2009.

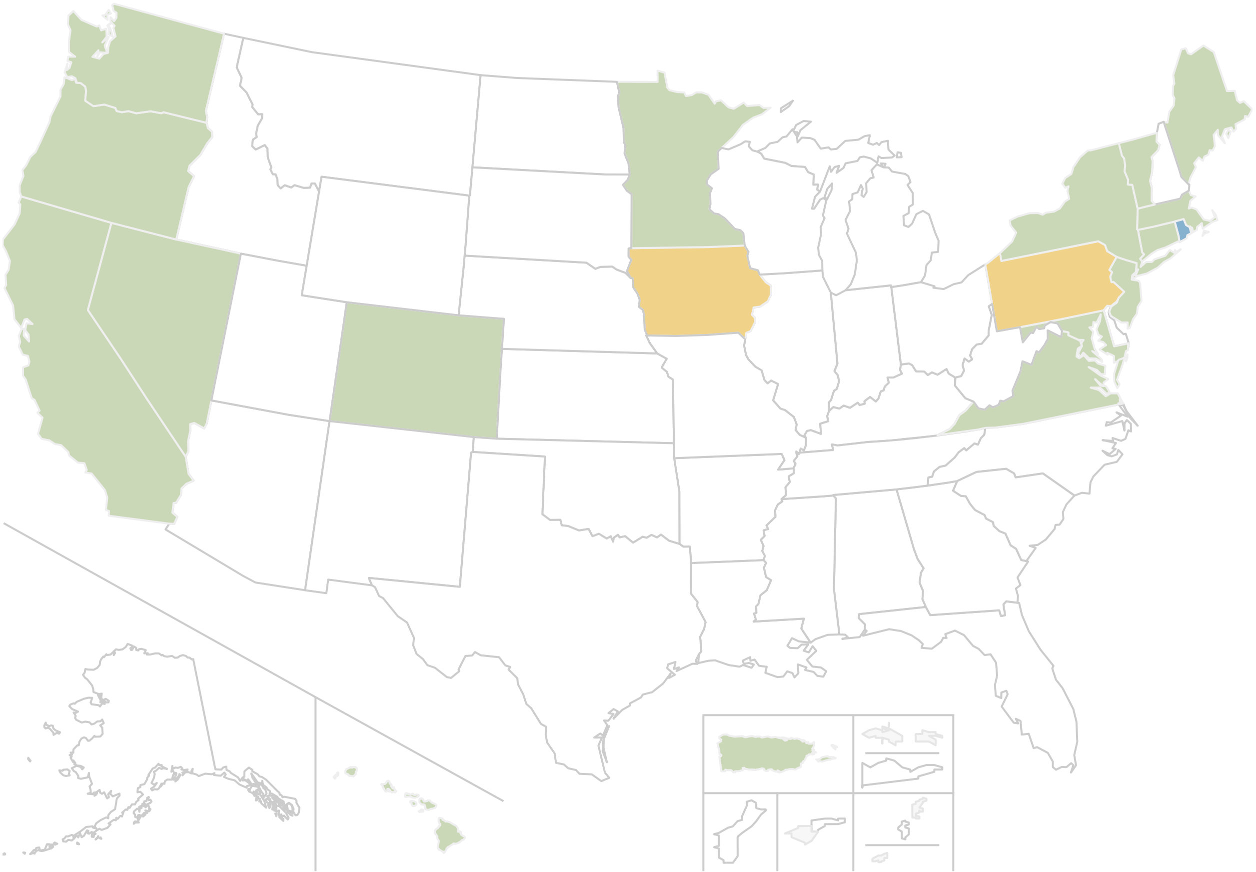
Generally, states have set targets as a future percentage reduction compared to a specific year's emissions levels or baseline, but the overall stringency of state programs can vary depending on the percentage reduction required and baseline used to measure such reductions.

State percentage reduction requirements range from 10% by 2020 up to 90% by midcentury. Several states—California, Connecticut, Maine, Massachusetts, New York, Oregon, Rhode Island, Vermont and Washington—use a 1990 baseline to measure emissions reductions, while the emissions baseline for Colorado, Minnesota and Nevada is 2005 and for Maryland and New Jersey it is 2006.

Connecticut and Vermont also implement a shifting baseline depending on the target year. For example, Connecticut uses a 1990 emissions baseline for its 2020 targets, but a 2001 emissions baseline for its 2030 and 2050 targets. Vermont uses a 2005 baseline for its near-term target and a 1990 baseline for its targets in 2030 and 2050.

Additionally, a number of states are statutorily required to conduct a GHG emissions inventory or reporting process to measure emissions from major sources on an annual, biennial or triennial basis. Some states, including Alaska, Delaware, Louisiana, New Hampshire, New Mexico and North Carolina, as well as Washington, D.C., administer an inventory program without an explicit statutory directive. Some states, such as Iowa and Pennsylvania, are statutorily required to compile an emissions inventory but do not have a statutory mandate to reduce statewide emissions. Conversely, several states with statutory GHG reduction requirements also have a statutory mandate to compile an emissions inventory.

States with Statutory Greenhouse Gas Reduction and Reporting Requirements



☐ No Reduction/Reporting Requirements

🟩 Statutory Greenhouse Gas Reduction + Reporting Requirements

🟦 Statutory Greenhouse Gas Reduction Requirements

🟨 Statutory Greenhouse Gas Reporting Requirements

California (Reduction Targets and Mandatory Reporting)

- Established: 2006.
- Statutory Targets: 40% by 2030 (1990 baseline).
- Description: California initially enacted statutory GHG emissions reduction targets in the Global Warming Solutions Act of 2006, which required that the state Air Resources Board (CARB) establish targets for reducing GHG emissions to 1990 levels by 2020. This 2006 legislation also directed CARB to adopt regulations governing the state's GHG emissions reporting process no later than Jan. 1, 2008. CARB was directed to develop a program requiring the reporting and verification of GHG emissions in the state and develop mechanisms for enforcement and compliance. Cal. Health & Safety Code § 38530. Information about CARB's mandatory greenhouse gas reporting regulation can be found here. In 2016, California extended its GHG emissions reduction targets by enacting SB 32, which required that CARB ensure GHG emissions are reduced to 40% below 1990 levels by 2030.

Colorado (Reduction Targets and Mandatory Reporting)

- Established: 2019.
- Statutory Targets: 26% by 2025; 50% by 2030; 90% by 2050 (2005 baseline).
- Description: In 2019, Colorado enacted comprehensive climate legislation directing the state Air Quality Control Commission (AQCC) to promulgate implementing regulations aimed at achieving statewide emissions reductions below 2005 levels of at least 26% by 2025, 50% by 2030 and 90% by 2050. Of note, House Bill 1261 requires the AQCC to identify, solicit stakeholder input from, and consider impacts on communities disproportionately impacted by climate change. Colo. Rev. Stat. § 25-7-102. Colorado also enacted a separate piece of legislation (Senate Bill 96) in 2019, which established specific statutory requirements for statewide GHG reporting. Under this provision, the AQCC is required to adopt rules with monitoring and public reporting requirements for GHG emitters. Such reporting requirements are designed to support the state's GHG inventory efforts. The state Air Pollution Control Division is now also required to update Colorado's GHG inventory at least every two years and include emissions forecasts tracking progress made toward achieving the state's GHG reduction targets. Colo. Rev. Stat. § 25-7-140.

Connecticut (Reduction Targets and Mandatory Reporting)

- Established: 2008.
- Statutory Targets: 10% by 2020 (1990 baseline); 45% by 2030 (2001 baseline); 80% by 2050 (2001 baseline).
- Description: Connecticut bolstered its statewide GHG reduction goals initially established in 2004 by enacting a comprehensive 2008 Global Warming Solutions Act (HB 5600), establishing binding GHG reduction requirements and mandating a statewide emissions inventory. Under this provision, the state is required to reduce GHG emissions by 10% below 1990 levels by 2020, 45% below 2001 levels by 2030, and 80% below 2001 levels by 2050. Conn. Gen. Stat. § 22a-200a. Additionally, the commissioner of Energy and Environmental Protection was required to publish a GHG inventory no later than July 1, 2010, and develop a schedule of regulatory actions no later than July 1, 2012, and every three years thereafter showing progress toward the state's GHG reduction targets. Conn. Gen. Stat. § 22a-200b.The state's GHG emissions inventory reporting can be found here.

Hawaii (Reduction Targets and Mandatory Reporting)

- Established: 2007; 2018.
- Statutory Targets: Carbon neutrality by 2045.
- Description: Hawaii enacted House Bill 2182 (2018), requiring that the state achieve a zero-emissions economy no later than 2045. In particular, state law requires that Hawaii "sequester more atmospheric carbon and greenhouse gases than emitted within the State as quickly as practicable, but no later than 2045." Hawaii Rev. Stat. §225P-5. More than 10 years earlier, Hawaii enacted a law mandating that the director of health adopt rules "requiring the reporting and verification of statewide greenhouse gas emissions." Hawaii Rev. Stat. § 342B-72. Additional information about Hawaii's GHG emissions inventory regulations and reporting can be found here.

Iowa (Mandatory Reporting Only)

- Established: 2007.
- Statutory Targets: None.
- Description: State law requires the Department of Natural Resources to submit an annual GHG emissions report starting in 2011 and in every year thereafter. Iowa also administers a voluntary GHG reporting registry to track companies that reduce their GHG emissions or increase efficiency. Iowa Code § 455B.104; Iowa Code § 455B.152. Additional information about Iowa's GHG emissions inventory and reporting process can be found here.

Maine (Reduction Targets and Mandatory Reporting)

- Established: 2003; 2019.
- Statutory Targets: 45% by 2030; 80% by 2050 (1990 levels).
- Description: Maine became the first state to enact binding statutory GHG emissions reduction requirements in 2003, mandating a return to 1990 emissions levels by 2010 with additional reductions in future years. Under this law, Maine was required to reduce statewide GHG emissions to 10% below 1990 levels by 2020. Of note, Maine's long-term targets required reductions "sufficient to eliminate any dangerous threat to the climate," including a potential 75-80% reduction below 2003 levels. This same legislation also mandated that the Department of Environmental Protection create an annual statewide GHG emissions inventory. Me. Stat. Ann. tit. 38 § 575. Information about Maine's GHG emissions inventory program can be found here. In 2019, Maine enacted legislation repealing and replacing its existing GHG reduction targets with enforceable long-term reduction targets of 45% below 1990 emissions levels by 2030 and 80% below 1990 emissions levels by 2050. Me. Rev. Stat. Ann. tit. 38 § 576-A.

Maryland (Reduction Targets and Mandatory Reporting)

- Established: 2009; 2016.
- Statutory Targets: 25% by 2020; 40% by 2030 (2006 baseline).

- Description: In 2016, Maryland reauthorized and extended its statewide GHG targets to require a 40% reduction below 2006 levels by 2030. Previously, the state had enacted the Greenhouse Gas Reduction Act of 2009, setting reduction targets of 25% below 2006 levels by 2020 and establishing a long-term goal of reducing statewide emissions by up to 90% below 2006 levels by 2050. The 2016 reauthorization reaffirmed these existing targets, set a new target for 2030 and required the state Department of Environment to submit a final plan to achieve the 2030 emissions reduction goals no later than Dec. 31, 2019. Md. Ann. Code art. Environment, § 2-1201; Md. Ann. Code art. Environment, § 2-1204; Md. Ann. Code art. Environment, § 2-1204.1. The initial 2009 legislation also required the Department of Environment to publish a statewide GHG emissions inventory every three years starting in 2011. Md. Environment Code Ann. § 2–1203. In 2022, Maryland passed SB 528 (Climate Solutions Now Act), which requires the Department of the Environment to submit a proposed plan that reduces statewide greenhouse gas emissions by 60% (from 2006 levels) by 2031.

Massachusetts (Reduction Targets and Mandatory Reporting)

- Established: 2008.
- Statutory Targets: 85% by 2050 (1990 baseline).
- Description: Massachusetts enacted its comprehensive Global Warming Solutions Act in 2008, requiring the Department of Environmental Protection to establish targets for GHG emissions reductions below 1990 levels of between 10% and 25% by 2020 and 80% by 2050. The department is also required to implement interim reduction targets for 2030 and 2040 aimed at achieving the 2050 emissions goal. The 2008 act further required the department to adopt regulations mandating reporting and verification of GHG emissions in the state. Such regulations must establish a regional reporting registry, require annual reporting for Title V permit facilities, and require annual reporting for stationary source facilities emitting more than 5,000 tons of carbon dioxide equivalent per year. In addition, the regulations must facilitate voluntary GHG emissions reporting, as well as require reporting from electric generation sources, including all retail sellers of electricity such as electric utilities and municipal electric departments. The department was also required to implement compliance monitoring and enforcement to ensure a rigorous accounting of emissions and that regulated entities maintain records of reported emissions. Mass. Gen. Laws Ann. ch. 21N et seq. In 2021, the state passed SB 9, increasing the 2050 target from 80% to 85%, with the goal of achieving net-zero emissions by 2050 and an interim target of reducing emissions at least 75% below 1990 levels by 2040. Pursuant to Mass. Gen. Laws Ann. ch. 21N et seq, the state also set interim targets in 2022 to reduce GHG emissions 33% by 2025 and 50% by 2030 from 1990 levels.

Minnesota (Reduction Targets and Mandatory Reporting)

- Established: 2007; 2009.
- Statutory Targets: 30% by 2025; 80% by 2050 (2005 baseline).
- Description: In 2007, Minnesota enacted the Next Generation Energy Act, comprehensive climate legislation requiring state emissions reductions below 2005 levels of at least 15% by 2015, 30% by 2025, and 80% by 2050. The act also required the commissioner of commerce to submit a climate action plan meeting certain requirements to the Minnesota Legislature no later than Feb. 1,

2008. Minn. Stat. § 216H.01 et seq. In 2009, the state enacted legislation requiring the commissioner of the state Pollution Control Agency to establish a GHG inventory. The inventory must include emissions from facilities required to obtain a Title V permit under federal Clean Air Act requirements and facilities emitting more than a certain threshold amount between 10,000 and 25,000 tons of carbon dioxide equivalent per year. Minn. Stat. § 216H.021. The state currently requires facilities with certain emissions permits to report GHG emissions. Additional information about the state's GHG emissions reporting requirements can be found here.

Nevada (Reduction Targets and Mandatory Reporting)

- Established: 2007; 2019.
- Statutory Targets: 28% by 2025; 45% by 2030 (2005 levels); near-zero by 2050.
- Description: In 2019, Nevada enacted legislation establishing statutory reduction targets for the first time and updating its GHG emissions inventory mandate, initially established in 2007, to include specific reporting requirements. The new law establishes GHG reduction targets below 2005 emissions levels of 28% by 2025 and 45% by 2030. The law further establishes a long-term target of zero or near-zero GHG emissions by 2050. Additionally, the state Department of Conservation and Natural Resources must issue a statewide inventory no later than Dec. 31, 2019, and annually thereafter that provides a 20-year forecast of GHG emissions in the state. The annual inventory report must include GHG emissions projections for certain sectors, including electricity production and transportation. The state must also project emissions for certain sectors in its GHG inventory, reporting every four years, including from industry, commercial and residential, agriculture, and land use and forestry. The reporting must also include a statement of policies aimed at reducing emissions from the identified sectors and, in certain years, a quantification of emissions reductions necessary to meet 2025 and 2030 GHG reduction targets. Nev. Rev. Stat. § 445B.380; Senate Bill 254 (2019).

New Jersey (Reduction Targets and Mandatory Reporting)

- Established: 2007.
- Statutory Targets: 1990 emissions by 2020; 80% by 2050 (2006 baseline).
- Description: In 2007, New Jersey enacted the Global Warming Response Act of 2007, comprehensive climate legislation requiring state emissions reductions to 1990 levels by 2020 and to 80% below 2006 levels by 2050. The state was also required to conduct an inventory of current, 2006 and 1990 statewide GHG emissions no later than 2008. The 2007 Act further requires that the state issue an annual report measuring statewide emissions and monitoring progress toward 2020 and 2050 emissions targets. The following entities are required to report their GHG emissions: Fossil fuel manufacturers and distributers including, but not limited to, oil refineries and storage facilities, natural gas pipelines, fuel wholesalers and retail distributors; electricity generators located in-state; electricity generators that deliver for sale and end-use in-state; gas utilities; and other major emitters, as determined by the department. N.J. Rev. Stat. § 26:2C-37 et seq.

New York (Reduction Targets and Mandatory Reporting)

- Established: 2019.
- Statutory Targets: 40% by 2030; 85% by 2050 (1990 baseline); net-zero GHG emissions by 2050.
- Description: In 2019, New York enacted the Climate Leadership and Community Protection Act, comprehensive climate legislation committing the state to net-zero greenhouse gas emissions by 2050. It also caps GHG emissions at 60% of 1990 levels (40% reduction) and at 15% (85% reduction) by 2050. The remaining 15% under the state's net-zero goal will be achieved through greenhouse gas emissions offset projects. The 2019 Act further requires the Department of Environmental Conservation to issue a report on state GHG emissions requirements no later than two years after the Act's effective date and every year thereafter. Senate Bill 6599 (2019).

Oregon (Reduction Targets and Mandatory Reporting)

- Established: 2007.
- Statutory Targets: 10% by 2020; 75% by 2050 (1990 baseline).
- Description: In 2007, Oregon enacted HB 3543 requiring the state to reduce GHG emissions starting in 2010 and establishing future targets for reductions below 1990 levels of 10% by 2020 and 75% by 2050. It also established the Oregon Global Warming Commission to coordinate state and local efforts to achieve the 2020 and 2050 reduction targets. The Commission is required to submit a biennial report describing the state's progress toward meeting its GHG reduction mandates, including trends in state GHG emissions. Or. Rev. Stat. § 468A.260. The state Environmental Quality Commission adopted GHG reporting rules in 2008. The state's GHG regulatory reporting requirements can be found here. Or. Rev. Stat. § 468A.200 et seq.

Pennsylvania (Mandatory Reporting Only)

- Established: 2008.
- Statutory Targets: None.
- Description: Pennsylvania's Department of Environmental Protection is statutorily required to compile an annual GHG emissions inventory establishing emissions trends and major sector contributions, including GHG emissions from "transportation, electricity generation, industrial, commercial, mineral and natural resources, production of alternative fuel, agriculture and domestic sectors." Pa. Stat. Ann. tit. 71, § 1361.4. Additional information about the state's climate programs and the 2018 GHG inventory can be found here.

Rhode Island (Reduction Targets Only)

- Established: 2014.
- Statutory Targets: 10% by 2020; 45% by 2035; 80% by 2050 (1990 baseline).
- Description: Rhode Island enacted the Resilient Rhode Island Act of 2014, establishing targets for GHG reductions below 1990 levels of 10% by 2020, 45% by 2035, and 80% by 2050. In 2021, R.I. Gen. Laws §

42-6.2-2 added a goal of net-zero GHG emissions by 2050. It also created the Climate Change Coordinating Council to oversee, assess, integrate and coordinate efforts to address climate change.

Vermont (Reduction Targets and Mandatory Reporting)

- Established: 2005; 2020.
- Statutory Targets: 26% by 2025 (2005 baseline); 40% by 2030 (1990 baseline); 80% by 2050 (1990 baseline).
- Description: In 2020, Vermont enacted enhanced and enforceable GHG reduction targets and created a climate council through HB 688. The state's previous goals, as established in 2005, were reducing greenhouse gas emissions below 1990 levels by 25% by 2012, 50% by 2028, and if practicable by 75% by 2050. Additionally, Vermont's secretary of natural resources is statutorily required to publish an annual GHG inventory until 2028, or until the state engages in alternative regional or federally-mandated GHG emissions reporting. Vt. Stat. Ann. tit. 10, § 578; Vt. Stat. Ann. tit. 10, § 582; HB 688 (2020).

Virginia (Reduction Targets and Mandatory Reporting)

- Established: 2020.
- Statutory Targets: Net-zero economy by 2045.
- Description: In 2020, Virginia enacted legislation establishing as an energy policy objective creating reduction goals necessary to achieve a statutory target of net-zero GHGs across economic sectors by 2045. Va. Code Ann. § 67-101; Senate Bill 94 (2020). In 2021, the state enacted Senate Bill 1282, which requires state regulators to conduct a statewide GHG emissions inventory every four years.

Washington (Reduction Targets and Mandatory Reporting)

- Established: 2008; 2020.
- Statutory Targets: 45% by 2030; 70% by 2040; 95% by 2050 (1990 baseline); net-zero economy by 2050.
- Description: Washington enacted HB 2311 in 2020, enhancing the state's greenhouse gas emissions reduction targets and establishing a net-zero economy target for 2050. The state's previous reduction targets as enacted in 2008 (HB 2815) were 25% by 2035 (1990 baseline); 50% by 2050 (1990 baseline) or 70% below expected emissions by 2050. See also Wash. Rev. Code § 70.235.020. The 2020 legislation also enhanced the state's emissions reporting requirements for crucial sectors (agriculture, manufacturing, buildings, transportation and electricity) in addition to statewide levels of GHGs. The state initially enacted GHG reporting requirements through legislation in 2010. Wash. Rev. Code § 70.94.151.

Puerto Rico (Reduction Targets and Mandatory Reporting)

- Established: 2019.
- Statutory Targets: 50% in five years (2025) with a 100% renewable energy target by 2041.
- Description: In 2019, Puerto Rico enacted comprehensive climate and clean energy legislation aimed at reducing the state's dependence on fossil fuels. In particular, the bill requires a 50% reduction in statewide GHG emissions over the next five years and sets ambitious renewable energy targets of 100% by 2041. The law further requires Puerto Rico's Department of Natural and Environmental Resources or other jurisdictional entity to annually compile and publish a GHG emissions inventory. Six GHGs must be measured as part of the inventory. Puerto Rico Senate Bill 773 (2019).

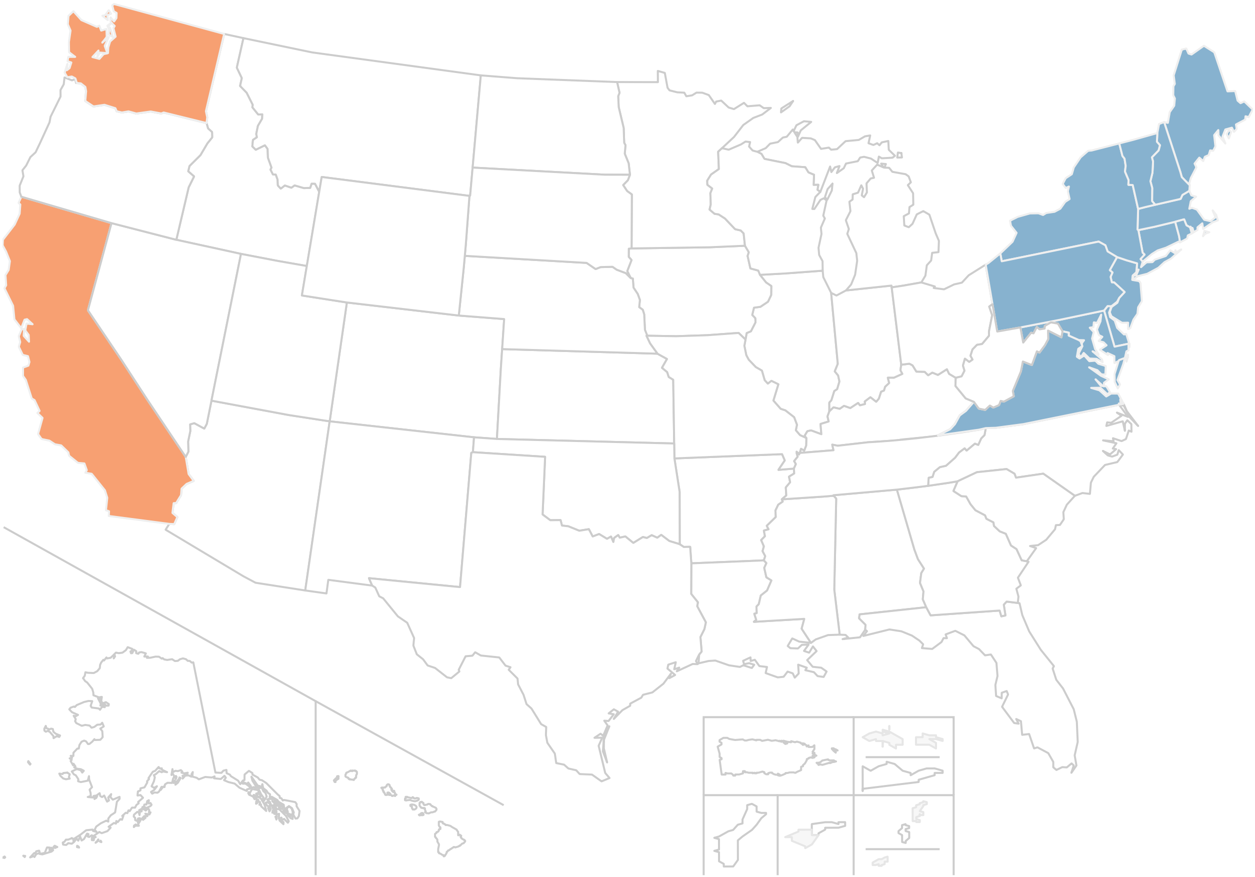
Market-based Policies

Several states have also implemented market-based policies aimed at limiting GHG emissions from major sectors. Such policies are implemented at the state level and through regional agreements. For the purposes of this section, we highlight those carbon pricing policies implemented through regulation.

Two primary carbon pricing regional agreements focus on limiting GHG emissions from major sectors. The first, the Regional Greenhouse Gas Initiative (RGGI), is focused on reducing GHG emissions from the power sector. The second, the Transportation Climate Initiative (TCI), is aimed at reducing emissions from the transportation sector.

At least one state, Massachusetts, is a participant in RGGI and TCI and also implements a state program, parallel to RGGI, limiting GHG emissions from certain power plants that rely on fossil fuels. California and Washington are the only states currently implementing an in-state multi-sector cap-and-trade program. Additionally, Washington's Clean Air Rule, adopted in 2016, established a market-based program limiting emissions from major in-state stationary sources and petroleum and natural gas distributors, has been suspended following a decision from the Washington state Supreme Court striking down portions of the rule.

States with Market-based Policies



☐ Do not have market-based policies

🟩 Participate in TCI only.

🟦 Participate in RGGI and TCI

🟨 Participate in TCI and RGGI Pending

🟧 In-State Cap-and-Trade Program

In-State Policies

California

In implementing the Global Warming Solutions Act of 2006 (AB 32), the California Air Resources Board (CARB) adopted by regulation a multi-sector cap-and-trade program rule in 2011. The initial rule established an annual emissions allowance budget from 2013 to 2020 and phased-in requirements for regulated entities during three compliance periods. Electricity generators and industrial facilities emitting 25,000 metric tons of carbon dioxide equivalent (CO2e) or more were required to comply with the cap during the first compliance period starting in 2013. The cap took effect for natural gas and fuel suppliers meeting or exceeding the 25,000 CO2e metric ton threshold during the second compliance period starting in 2015. The program was designed to regulate the sources responsible for 85% of the state's GHG emissions.

California's cap-and-trade regulation has been updated several times over the course of the program. Of note, in 2012 CARB adopted regulations authorizing "linkage" with other GHG emissions trading programs, which provided for the use of allowances and offsets earned in external cap-and-trade programs for compliance with California's program. California's program linked with Québec's cap-and-trade program in 2014. In 2017, California enacted AB 398, which extended the program's cap to 2031.

California's current regulations provide for an annual emissions allowance budget (in millions) of 346.3 in 2019, decreasing annually down to 193.8 in 2031.

Washington

In 2021, Washington state passed the Climate Commitment Act (SB 5126), which caps and reduces GHG emissions from their largest emitting sources and industries. The program was set to begin early 2023 and requires businesses that emit over 25,000 metric tons of carbon a year to purchase allowances for the additional emissions. The program creates a limited number of state-issued carbon allowances to be auctioned four times a year to companies that exceed the 25,000 metric-ton threshold. The number of allowances available at auctions will decrease each year, lowering the cap for overall emissions in the state.

Companies that choose not to comply will be fined $5,000 per violation per day. Companies that meet the criteria have until Nov. 1, 2024, to have 30% of their total 2023 emissions covered as the state makes the transition. A few companies will be classified as "emissions-intensive, trade-exposed" businesses to spare them from purchasing allowances right away to ensure big businesses don't leave the state.

Regional Agreements

Regional Greenhouse Gas Initiative

The Regional Greenhouse Gas Initiative (RGGI), formed in 2009, is the nation's first binding cap-and-trade program aimed at reducing GHG emissions from the power sector. Twelve states—Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, Vermont, and Virginia—currently participate in the program, with Pennsylvania being the latest state to rejoin RGGI. Other states are looking to participate in the program in the coming years.

The program is enforced through independent regulations adopted by participating states and is designed around a regional emissions allowance cap—one allowance provides for regulated entities to emit one short ton of CO2. In 2014, RGGI states adjusted down the regional cap to account for banked allowances. The adjusted allowance cap is 93.3 million in 2023. In 2017, the RGGI states extended the emissions cap out to 2030. Additional revisions to the cap are expected to be made in 2021 through 2025.

Transportation and Climate Initiative

The Transportation and Climate Initiative (TCI) was formed in 2010 by a coalition of Northeast and Middle Atlantic states and Washington, D.C., with the intent of reducing carbon emissions from the transportation sector. Fourteen jurisdictions, including 13 states—Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, North Carolina, Pennsylvania, Rhode Island, Vermont and Virginia—and Washington, D.C., participate in the TCI.

In 2018, TCI members committed to designing a regional cap-and-invest policy to reduce carbon emissions from the transportation sector. The policy would provide for each TCI jurisdiction to invest program proceeds “into low-carbon and more resilient transportation infrastructure.”

On Oct. 1, 2019, the TCI released a framework for its draft regional policy proposal, addressing which entities would be regulated under the program, emissions reporting and monitoring requirements and equity concerns. This framework was followed by a draft Memorandum of Understanding (MOU) released in mid-December 2019 that would, in addition to committing participating jurisdictions to implementing the cap-and-invest program, require participants to jointly develop a model rule. A draft model rule for potential adoption by TCI jurisdictions was released in March 2021. The model rule includes provisions related to covered emissions, emissions reporting, and allowance budgets, among other requirements. The model rule also includes specific provisions aimed at addressing concerns related to equity and environmental justice.

Additionally, in December 2020, Connecticut, Rhode Island, Massachusetts and the District of Columbia entered into an MOU to implement the TCI Program, with the first reporting period starting as early as January 2022. They will be the first jurisdictions to launch the program. Other Northeast, Southeast and Middle Atlantic states committed to working with Connecticut, Rhode Island, Massachusetts and the District of Columbia in developing the program while advancing emissions reduction policies in the transportation sector at both the state and regional level. While a number of TCI jurisdictions signed this statement of support, Maine did not. You can find additional information regarding the TCI-Program’s policy design process here.

Related Resources

Updated March 19, 2024

2023 Legislative Energy Trends

This report highlights trends in state energy legislation from 2023, ranging from renewable energy to energy security and grid development. State legislatures considered well over 3,000 bills in 2023, enacting almost 17% of those bills. These actions reflect state lawmakers’ diverse responsibilities and their varied approach to ensuring a robust, resilient and sustainable energy system that adequately meets states' energy needs.

Energy

Updated March 07, 2024

Love It or Hate It, Daylight Saving Time Is Here Again

The national debate and state actions related to daylight saving time are continuing into 2024. For the foreseeable future, though, clock changing remains the law of the land in all but a few places.

Energy, Health

State Legislatures News

Updated March 06, 2024

Supreme Court Hears Challenge to the EPA's 'Good Neighbor' Plan

The Supreme Court will consider whether to limit an effort by the Environmental Protection Agency to curtail air pollution that drifts across state lines.

Energy, Environment and Natural Resources, State-Federal

State Legislatures News

SMARTCITIESDIVE

Legal threats to city, state natural gas bans: A timeline

The nation's first gas ban was overturned. One state changed its building codes to avoid legal challenges. Here's the latest on state and local efforts to ban natural gas.

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Ysabelle Kempe
Editor

Gas bans regularly pop up in headlines nationwide. Sometimes the news captures advances, such as when another jurisdiction mandates that new construction be built all-electric. Other news is of setbacks, typically lawsuits filed by gas and construction groups to block such rules.

These legal challenges primarily center around a single question, said Amy Turner, director of the Cities Climate Law Initiative at Columbia University's Sabin Center for Climate Change Law: How much does the federal Energy Policy and Conservation Act preempt local and state building electrification rules?

The answer is pivotal for the dozens of cities and few states that have restricted gas hookups in new construction to stymie growing greenhouse gas emissions — and for the jurisdictions still hoping to pass such rules.

Even if EPCA-focused litigation doesn't ultimately succeed in blocking gas bans, Turner said she doesn't foresee well-funded gas industry players halting their pushback against them. "I would expect them to take up a different line of argument," she said. "This is existential for them."

Here's a play-by-play of the biggest news about gas bans and related litigation since a federal appeals court overturned Berkeley, California's first-in-the-nation rule in April 2023. Cities and states across the country will undoubtedly be watching for what happens next as they chart their decarbonization path forward.

Gas bans and legal challenges in 2023

April 17

A federal appeals court overturns Berkeley, California's first-in-the-nation ordinance banning gas in new construction, agreeing with the California Restaurant Association that the city bypassed federal energy regulations.

May 2

New York becomes the first state to pass a law banning gas in most new buildings through provisions in its fiscal year 2024 budget. Not included in the law is the option for cities and counties to override the ban, which some climate activists worried about before the law's passage.

May 22

In Washington state, a coalition including gas and building groups files a lawsuit in federal district court to block state building codes adopted in 2022 that require heat pumps in new residential and commercial construction, arguing that the codes violate the federal Energy Policy and Conservation Act.

May 24

Washington state building code officials vote to delay the heat pump rules for 120 days after their original effective date of

July 1, 2023, and begin revising the building codes to reduce the risk of their being overturned.

May 31

Berkeley files a petition for the federal appeals court to rehear the case regarding its gas ban. The city argues that the court misinterpreted the federal law the city was accused of violating. Less than two weeks later, the U.S. files an amicus brief in support of Berkeley's request.

July 10

Eugene, Oregon, reverses its ban on natural gas hookups in new, low-rise residential construction. Local opponents, largely funded by the state's largest gas utility, had gathered enough signatures for a citywide vote on the ban, and city officials said they were concerned about legal threats arising from the Berkeley decision.

Aug. 3

Gas and building groups drop their lawsuit to block new Washington state building codes requiring heat pumps in new construction, citing state officials' work to modify the rules. A federal judge in July had denied the industry groups' request to vacate the codes.

Sept. 8

Twenty-six local government leaders in California send a letter to Gov. Gavin Newsom urging him to urgently pursue statewide standards that would require new buildings to be all-electric. The letter says Newsom must step in with a "unified state standard," otherwise "many municipalities will be forced to backtrack on progress cutting emissions from buildings, due to insufficient resources to fight frivolous and opportunistic lawsuits."

Oct. 12

Gas and construction trade groups sue to block New York state's recently passed gas ban, arguing it violates EPCA.

Nov. 28

The Washington State Building Code Council approves revised codes that incentivize builders to choose electric heat pumps but erase language mandating heat pumps for heating water and rooms in homes.

Dec. 29

A coalition of construction contractor and heating fuels trade groups files a lawsuit against New York City in the federal court for the Southern District of New York, seeking to block the city from enforcing a law that effectively requires many new buildings to be all-electric. The groups argue the city's Local Law 154 — which passed in 2021 and first went into effect for some building types on Jan. 1, 2024 — violates EPCA and is contrary to the public interest. The law firm representing the plaintiffs is the same one that's representing the groups seeking to block Berkeley and New York state's gas bans.

Gas bans and legal challenges in 2024

Jan. 2

The U.S. Court of Appeals for the Ninth Circuit denies Berkeley's request for a rehearing of the case regarding its gas ban. The move leaves Berkeley with only one course of action if it wants to move the case forward in the court system: Try to take it to the U.S. Supreme Court.

March 22

The California Restaurant Association announces that Berkeley will immediately stop enforcing its ordinance while lawmakers go through the monthslong process to repeal it, per a settlement agreement between CRA and the city.

Is our timeline missing anything? To suggest additions, contact smart.cities.dive.editors@industrydive.com

08-Nov-2023 | 13:11 EST

MDU Resources Group Inc. And Cascade Natural Gas Downgraded To 'BBB', Outlooks Negative; Rating Actions On Other Subs

- MDU Resources Group Inc. (MDU) completed its strategic review of its construction services business, MDU Construction Services Group Inc. (CSG), and will divest CSG through a spinoff to MDU shareholders by year-end 2024. This announcement follows the successful May 2023 spinoff of MDU's construction materials business Knife River Corp.
- We expect the separation of these higher-risk businesses to reduce MDU's consolidated business risk while weakening consolidated financial measures given the loss of operating cash flows. However, with the completed and pending divestitures, MDU's credit profile no longer benefits from the moderate diversification through owning multiple uncorrelated business lines.
- Accordingly, we lowered our issuer credit ratings on MDU and subsidiary Cascade Natural Gas Corp. by one notch to 'BBB' from 'BBB+'. The outlooks are negative. We lowered our issue-level rating on Cascade's senior unsecured debt to 'BBB' from 'BBB+'.
- We affirmed our ratings on Montana-Dakota Utilities Co. and on Centennial Energy Holdings Inc., and our short-term ratings on MDU, Montana-Dakota, and Centennial.
- We affirmed our 'A-2' commercial paper rating on Montana-Dakota. In addition, we withdrew our 'A-3' commercial paper rating on Centennial after MDU terminated the program.
- We revised our outlook on Montana-Dakota to negative from developing and revised our outlook on Centennial to positive from developing.
- The negative outlook on MDU, Cascade, and Montana-Dakota reflects the possibility of weaker consolidated financial measures from higher leverage following the separation of CSG. Our base case post divestiture reflects funds from operations (FFO) to debt consistently below 15%.
- Our positive outlook on Centennial reflects our expectation that the remaining Centennial businesses, after the CSG spin-off, will be core to MDU. Therefore, we would likely align the Centennial issuer credit rating with the rating on the MDU group.

DALLAS (S&P Global Ratings) Nov. 8, 2023-- S&P Global Ratings today took the rating actions listed above. Our downgrades of MDU and Cascade reflect the more limited diversification of the remaining businesses under MDU. We previously viewed MDU as a conglomerate operating multiple uncorrelated business lines that together provided moderate diversification benefits to MDU's credit profile. This benefit resulted in one notch of uplift to our issuer credit rating on the company. However, with the completed and pending separation of the CSG businesses, MDU will no longer benefit from moderate diversification of having multiple uncorrelated business lines, resulting in a one-notch lowering of our issuer credit ratings on MDU and Cascade.

Due to the presence of insulating measures at Montana-Dakota, we affirmed our issuer credit rating on the company. We view existing insulation at Montana-Dakota as sufficient to rate the company up to one notch above MDU's group credit profile. Montana-Dakota's stand-alone credit profile (SACP) is 'bbb+', supporting our 'BBB+' issuer credit rating.

For further information regarding the insulation measures, please see Montana-Dakota Utilities full analysis published June 22, 2023.

We assess MDU's business risk profile above the midpoint for its respective category. We expect MDU's lower-risk, rate-regulated utilities will contribute a significantly greater proportion to consolidated EBITDA (about 55%), following the spinoff of Knife River, and before the spinoff of CSG. Although we expect Centennial's remaining nonutility businesses of CSG (prior to spinoff) and WBI Holdings Inc. (natural gas transportation and storage) to contribute about 45% to consolidated EBITDA, we would assess MDU's business risk profile above the midpoint for its assessment of satisfactory relative to peers. We expect business risk will further strengthen after the spinoff of CSG by year-end 2024.

The loss of Knife River and CSG's cash flows weaken MDU's consolidated financial measures. Our base-case scenario assumes MDU successfully spins off CSG by year-end 2024, resulting in the loss of its cash flows starting in 2025. In addition, we expect regulated utility capital spending to remain elevated to accommodate volumetric growth predominantly in Cascade's service territory, Montana-Dakota's

ongoing replacement of aging infrastructure, and WBI's ongoing expansion projects in the Bakken region. This incorporates a capital plan of between $500 million to $600 million annually through 2026.
Furthermore, in August, MDU realigned its dividend policy to a payout of 60%-70% of its regulated energy delivery earnings. In addition, we expect the disposal of its remaining shares in Knife River to provide over $300 million in cash proceeds (based on a $58 per share price assumption). Incorporating these assumptions, we forecast MDU's consolidated FFO to debt in the 14%-17% range for 2023-2025, compared with consolidated FFO to debt of 25% at year-end 2022. With the majority of MDU's cash flow now from utilities, we assess MDU's financial risk profile using our medial volatility benchmarks. These are more relaxed than the standard benchmarks we use for typical corporate issuers. This reflects MDR's lower-risk regulated utility operations and effective management of regulatory risk.

The repayment of over $1.1 billion in debt at Centennial strengthened its consolidated financial measures. Using proceeds from an $825 million one-time distribution from Knife River and new debt at MDU that the company intends to repay with the proceeds from the disposal of its remaining interest in Knife River, MDU repaid the entirety of Centennial's senior long-term debt, including about $455 million associated with Knife River and CSG, and about $645 million in outstanding term loans and borrowings under its revolving credit agreement. We forecast Centennial's stand-alone debt to EBITDA will improve to about 1.5x per year in 2023 and 2024 as compared to our prior expectations of 2x-2.5x over the same time period. Accordingly, we revised our assessment of Centennial's financial risk profile upward to intermediate from significant. After the spinoff of CSG (expected by year-end 2024), we expect Centennial's financial measures to weaken modestly following the cash flow loss.

We continue to incorporate a volatility adjustment at Centennial which reflects the potential for significant cash flow volatility at CSG during periods of stress. This volatility adjustment lowers its financial risk profile to intermediate from modest. The combination of a satisfactory business risk profile and intermediate financial risk profile, in addition to the strength of its consolidated financial measures within its respective financial risk profile category, raises Centennial's SACP to 'bbb-' from 'bb+'.

We revised upward our assessment of MDU's group support of Centennial. MDU's decision to spin off Centennial's higher-risk businesses is consistent with its stated strategy to focus on its core energy delivery businesses over the longer term. We believe this heightens the importance of Centennial's natural gas transportation and storage business under WBI, which we expect will contribute 100% of Centennial's EBITDA and 25% of MDU's consolidated EBITDA post-2024. Over 45% of WBI's revenues are generated through long-term transmission and storage contracts with affiliate Montana-Dakota; and given this relationship, we believe MDU will have a higher degree of support for Centennial. We therefore revised our group status on Centennial to strategically important from moderately strategic, reflecting our view that Centennial is unlikely to be sold, is important to the group's long-term strategy, has the long-term commitment of the group, and is a significant contributor to the MDU group.

MDU

The negative outlook on MDU reflects the possibility of weaker financial measures from higher leverage following the spinoff of CSG. Our base-case forecast incorporates MDU's consolidated FFO to debt in the 14%-17% range in 2023-2025.

We could lower our ratings on MDU by one notch over the next 12 to 18 months if the company's financial measures reflect higher leverage following the spinoff of CSG, such that FFO to debt is consistently below 15%.

We could revise the outlook to stable if MDU successfully spins off CSG, while maintaining FFO to debt consistently above 15%.

The negative outlook on Cascade reflects the potential for a one-notch downgrade if we lower our ratings on parent MDU.

We could lower our ratings on Cascade over the next 12 to 18 months if we lower our ratings on MDU.

We could revise the outlook to stable if we revise the outlook on MDU to stable.

Montana-Dakota Utilities

The negative outlook on Montana-Dakota reflects the potential for a one notch downgrade if we lower our ratings on parent MDU.

We could lower our ratings on Montana-Dakota over the next 12 to 18 months if we lower our ratings on MDU, or if Montana-Dakota's stand-alone financial measures weaken such that its FFO to debt is consistently below 13%.

We could revise the outlook to stable if we revise the outlook on MDU to stable, while Montana-Dakota maintains its stand-alone FFO to debt consistently above 13%.

Centennial

The positive outlook on Centennial reflects the potential for a one-notch upgrade if parent MDU maintains its credit quality consistent with current levels, following the spinoff of CSG, at which time we could align the ratings of Centennial with the group credit profile of MDU.

We could affirm our ratings on Centennial and revise the outlook to stable if we lower our ratings on parent MDU by one notch.

We could raise our ratings on Centennial if we affirm our ratings on MDU following the spinoff of CSG, at which time we would align the ratings on Centennial with the group credit profile of MDU.

Related Criteria

- Criteria | Corporates | Industrials: Key Credit Factors For The Midstream Energy Industry, Nov. 15, 2021
- General Criteria: Environmental, Social, And Governance Principles In Credit Ratings, Oct. 10, 2021
- General Criteria: Group Rating Methodology, July 1, 2019
- Criteria | Corporates | General: Corporate Methodology: Ratios And Adjustments, April 1, 2019
- Criteria | Corporates | General: Reflecting Subordination Risk In Corporate Issue Ratings, March 28, 2018
- General Criteria: Methodology For Linking Long-Term And Short-Term Ratings, April 7, 2017
- Criteria | Corporates | General: Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Dec. 16, 2014
- General Criteria: Methodology: Industry Risk, Nov. 19, 2013
- General Criteria: Country Risk Assessment Methodology And Assumptions, Nov. 19, 2013
- Criteria | Corporates | Utilities: Key Credit Factors For The Regulated Utilities Industry, Nov. 19, 2013
- Criteria | Corporates | General: Corporate Methodology, Nov. 19, 2013
- General Criteria: Methodology: Management And Governance Credit Factors For Corporate Entities, Nov. 13, 2012
- General Criteria: Principles Of Credit Ratings, Feb. 16, 2011

Certain terms used in this report, particularly certain adjectives used to express our view on rating relevant factors, have specific meanings ascribed to them in our criteria, and should therefore be read in conjunction with such criteria. Please see Ratings Criteria at www.spglobal.com/ratings for further information. Complete ratings information is available to RatingsDirect subscribers at www.capitaliq.com. All ratings affected by this rating action can be found on S&P Global Ratings' public website at www.spglobal.com/ratings.

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BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

Nancy Lange	Chair
Dan Lipschultz	Commissioner
Matthew Schuerger	Commissioner
Katie J. Sieben	Commissioner
John A. Tuma	Commissioner

In the Matter of the Application of Otter Tail Power Company for Authority to Increase Rates for Electric Service in Minnesota

ISSUE DATE: May 1, 2017

DOCKET NO. E-017/GR-15-1033

FINDINGS OF FACT, CONCLUSIONS, AND ORDER

Contents

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PROCEDURAL HISTORY

I. Initial Filings and Orders

On February 16, 2016, Otter Tail Power Company (Otter Tail, or the Company) filed this general rate case seeking an annual rate increase of $19,295,627, or approximately 9.8%. The filing included a proposed interim-rate schedule.

On the same date, the Company filed a petition to establish a new base cost of energy for the period during which interim rates would be in effect; that petition was granted by order dated April 14, 2016.[1]

Also on April 14, 2016, the Commission issued three orders in this case:

- an order finding the rate-case filing substantially complete and suspending the proposed final rates;
- a notice and order for hearing referring the case to the Office of Administrative Hearings for contested-case proceedings; and
- an order setting interim rates for the period during which the rate case was being resolved.

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[1] *In the Matter of the Application of Otter Tail Power Company for Approval of a New Base Cost of Energy*, Docket No. E-017/MR-15-1034, Order Setting New Base Cost of Energy (April 14, 2016).

II. The Parties and Their Representatives

The following parties appeared in this case:

- Otter Tail Power Company, represented by Bruce Gerhardson, Associate General Counsel; Cary Stephenson, Associate General Counsel; Richard J. Johnson, Moss & Barnett, P.A.; and Patrick T. Zomer, Moss & Barnett, P.A.

- Minnesota Department of Commerce (the Department), represented by Linda S. Jensen and Peter E. Madsen, Assistant Attorneys General.

- Office of the Minnesota Attorney General–Residential Utilities and Antitrust Division (OAG), represented by Joseph C. Meyer and Joseph A. Dammel, Assistant Attorneys General.

- Minnesota Chamber of Commerce (the Chamber), represented by Richard J. Savelkoul, Martin & Squires, P.A.

- Forest Products Group, represented by Andrew P. Moratzka and Emma J. Fazio, Stoel Rives LLP.

- Fresh Energy, represented by Attorney Benjamin L. Passer.

III. Proceedings Before the Administrative Law Judge

The Office of Administrative Hearings assigned Administrative Law Judge (ALJ) Eric L. Lipman to hear the case.

The parties filed direct, rebuttal, and surrebuttal testimony prior to the opening of evidentiary hearings. The ALJ held evidentiary hearings in Saint Paul on October 13, 14, and 17, 2016. After the hearings the parties filed initial briefs, reply briefs, and proposed findings of fact and conclusions of law.

The ALJ also held four public hearings in the case, on the dates and at the locations set forth below:

- City Hall, Bemidji—August 24, 2016
- Cobblestone Inn, Crookston—August 24, 2016
- City Hall, Fergus Falls—August 25, 2016
- City Council Chambers, Morris—August 25, 2016

IV. Public Comments

The Administrative Law Judge held four public hearings, where the Company, the Department, the OAG, and the Commission’s staff were available to make presentations and field questions from members of the public.

All public comments are filed in the case record. Written comments are labeled "Public Comment," of which the Commission received one. The commenting member of the public opposed a rate increase.

V. Proceedings Before the Commission

On January 5, 2017, the Administrative Law Judge filed his Findings of Fact, Summary of Public Testimony, Conclusions of Law, and Recommendation (the ALJ's Report). The following parties filed exceptions to the ALJ's Report under Minn. Stat. § 14.61 and Minn. R. 7829.2700: the Company, the Department, the OAG, Fresh Energy, and the Minnesota Chamber of Commerce.

On February 23 and March 2, 2017, the Commission heard oral argument from and asked questions of the parties. On March 2, 2017, the record closed under Minn. Stat. § 14.61, subd. 2.

Having examined the entire record in this case, and having heard the arguments of the parties, the Commission makes the following findings, conclusions, and order.

FINDINGS AND CONCLUSIONS

I. The Ratemaking Process

A. The Substantive Legal Standard

The legal standard for utility rate changes is that the new rates must be just and reasonable.[2] The Minnesota Supreme Court has described the Commission's statutory mandate for determining whether proposed rates are just and reasonable as "broadly defined in terms of balancing the interests of the utility companies, their shareholders, and their customers," citing Minn. Stat. § 216B.16, subd. 6.[3] That statute is set forth in pertinent part below:

> The commission, in the exercise of its powers under this chapter to determine just and reasonable rates for public utilities, shall give due consideration to the public need for adequate, efficient, and reasonable service and to the need of the public utility for revenue sufficient to enable it to meet the cost of furnishing the service, including adequate provision for depreciation of its utility property used and useful in rendering service to the public, and to earn a fair and reasonable return upon the investment in such property.

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[2] Minn. Stat. § 216B.16, subds. 4, 5, and 6.

[3] *In re Interstate Power Co.*, 574 N.W.2d 408, 411 (Minn. 1998).

B. The Commission's Role

While the Public Utilities Act provides baseline guidance on the ratemaking treatment of different kinds of utility costs, it generally makes only threshold determinations on rate recoverability, leaving to the Commission the tasks of determining (a) the accuracy and validity of claimed costs; (b) the prudence and reasonableness of claimed costs; and (c) the compatibility of claimed costs with the public interest.

In ratemaking, therefore, the Commission must decide a wide range of issues, ranging from the accuracy of the financial information provided by the utility, to the prudence and reasonableness of the underlying transactions and business judgments, to the proper distribution of the final revenue requirement among different customer classes.

These diverse issues require different analytical approaches, involve different burdens of proof, and require the Commission to exercise different functions and powers. In ratemaking the Commission acts in both quasi-judicial and quasi-legislative capacities: As a quasi-judicial body it engages in traditional fact-finding, and as a quasi-legislative body it applies its institutional expertise and judgment to resolve issues that turn on both factual findings and policy judgments. As the Supreme Court has explained,

> [I]n the exercise of the statutorily imposed duty to determine whether the inclusion of the item generating the claimed cost is appropriate, or whether the ratepayers or the shareholders should sustain the burden generated by the claimed cost, the MPUC acts in both a quasi-judicial and a partially legislative capacity. To state it differently, in evaluating the case, the accent is more on the inferences and conclusions to be drawn from the basic facts (i.e., the amount of the claimed costs) rather than on the reliability of the facts themselves. Thus, by merely showing that it has incurred, or may hypothetically incur, expenses, the utility does not necessarily meet its burden of demonstrating it is just and reasonable that the ratepayers bear the costs of those expenses.[4]

C. The Burden of Proof

Under the Public Utilities Act, utilities seeking a rate increase have the burden of proof to show that the proposed rate change is just and reasonable.[5] Any doubt as to reasonableness is to be resolved in favor of the consumer.[6]

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[4] *In re N. States Power Co.*, 416 N.W.2d 719, 722–23 (Minn. 1987) (citation omitted).

[5] Minn. Stat. § 216B.16, subd. 4.

[6] Minn. Stat. § 216B.03.

On purely factual issues, the Commission acts in its quasi-judicial capacity and weighs evidence in the same manner as a district court, requiring that facts be proved by a preponderance of the evidence. On issues involving policy judgments, the Commission acts in its quasi-legislative capacity, balancing competing interests and policy goals to arrive at the resolution most consistent with the broad public interest.

Utilities seeking rate changes must therefore prove not only that the facts they present are accurate, but that the costs they seek to recover are rate-recoverable, that the rate recovery mechanisms they propose are permissible, and that the rate design they advocate is equitable, under the "just and reasonable" standard set by statute. As the Court of Appeals explained, quoting the Supreme Court,

> A utility seeking to change its rates has the burden of proving by a preponderance of the evidence that its proposed rate change is just and reasonable. Minn. Stat. § 216B.16, subd. 4 (1986). "Preponderance of the evidence" is defined for ratemaking proceedings as "whether the evidence submitted, even if true, justifies the conclusion sought by the petitioning utility when considered together with the Commission's statutory responsibility to enforce the state's public policy that retail consumers of utility services shall be furnished such services at reasonable rates."[7]

II. Rate Case Overview

Otter Tail seeks an annual rate increase of $19,295,627, or 9.80%, to cover a revenue deficiency arising in part from what it described as its "largest capital expenditure program in its history." The Company projects that it will invest $858 million between 2016 and 2020 in capital projects.

According to the Company, it has invested approximately $536 million in capital projects between 2012 and 2015, and expects to invest an additional $858 million between 2016 and 2020. Investments in environmental improvements and transmission largely drove these costs, along with "routine replacements, upgrades, and extensions."

The average monthly impact of the proposed rate increase for a residential customer would be $9.53 per month or $114.36 per year. The impact on individual customers would be higher or lower depending on each individual customer's actual electric consumption. The Company proposed to increase fixed monthly charges and to shift more revenue responsibility to its residential classes.

The Company used a projected 2016 test year, based on actual data from fiscal year 2015.

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[7] *In re Minn. Power & Light Co.*, 435 N.W.2d 550, 554 (Minn. App. 1989) (citation omitted).

III. Summary of the Issues

Many initially contested issues were resolved in the course of evidentiary proceedings. The Administrative Law Judge found that the resolutions reached by the parties were reasonable and supported by record evidence; he recommended accepting them.[8] The Commission concurs.

Other issues remained contested. The following issues either were contested or otherwise require discussion.

Financial Issues

- ***Prorated Accumulated Deferred Income Tax Assets—***Should the Commission defer a determination on accounting for Accumulated Deferred Income Tax Assets in this case in anticipation that the Company will receive guidance from the IRS?
- ***Multi-Value Transmission Projects (MVPs)—***How should the Commission regard recovery for projects that are approved through the Midcontinent Independent System Operator (MISO) transmission-planning process, and classified as MVPs?
- ***Aircraft Expenses—***Are the Company's aircraft expenses recoverable through rates?
- ***Pension Asset and Other Post-Employment Benefit (OPEB) Liability—***Should these amounts and associated accumulated deferred income taxes be excluded from the test-year rate base?
- ***Discount Rates for Pension and OPEB Expenses—***What are the appropriate discount rates for these expenses?
- ***TailWinds Program—***Should the Company be permitted to recover costs for unsubscribed energy from non-enrolling customers?
- ***Reagents and Emissions Allowances—Fuel Clause Adjustment—***Should the Company be permitted to include test-year reagent cost and emissions-allowance amounts in the Base Fuel Cost, or to adjust them through the fuel clause adjustment?
- ***Cash Working Capital (CWC)—***Should the Commission adopt the ALJ's recommendation to adjust the amount of cash working capital by $244,109 in light of a settlement reached between the Company and the Department?
- ***Southwest Power Pool (SPP) Transmission Costs—***What amount of these transmission costs should be included in the test year and should differences be tracked?
- ***Management Incentive Compensation—***Are the Company's management incentive costs appropriate to include in the Company's test year?
- ***Charitable Contributions—***What amount of charitable contribution expenses should be included in the test year?
- ***Interim Rates Recoveries—***Did the Company appropriately adjust interim rate recovery of its Environmental Cost Recovery Rider, Transmission Cost Recovery Rider, and Renewable Resource Adjustment Rider?

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[8] ALJ's Report ¶¶ 172–265.

- ***Missouri River Energy Services Integrated Transmission Service Agreement——***What amount of the expenses associated with this agreement should be included in the test year?
- ***Operations & Maintenance (O&M) Expenses—***Is the increase in the Company's O&M budget reasonable?
- ***Investor Relations Expense—***What amount of these expenses should be included in the test year?
- ***Allowance for Funds Used During Construction (AFUDC) and Construction Work in Progress (CWIP)—*** Should the Company be permitted to continue placing CWIP in rate base and offsetting AFUDC from its income statement?
- ***Employee Expenses—***What amount of these expenses should be included in the test year?
- ***Lobbying & Organizational Dues—***What amount of these expenses should be included in the test year?

Cost-of-Capital Issues

- ***Return on Equity—***What is a fair and reasonable rate of return on equity for this Company, on this record, at this time?

Class-Cost-of-Service-Study (CCOSS) Issues

- ***CCOSS—***What action should the Commission take, if any, with respect to the Class Cost of Service Studies proposed in this case? What requirements, if any, should be established for future Otter Tail rate cases?

Sales Forecast

- ***Sales and Revenues***—What figures should be adopted for this case?
- ***Process Improvements***—How should Otter Tail improve its forecasting methods?

Rate-Design Issues

- ***Interclass Revenue Apportionment—***What percentage of the revenue requirement should be allocated to each customer class?
- ***Decoupling—***Should the Commission require the Company to propose or implement a revenue-decoupling rate design?
- ***Fixed Customer Charges—***At what level should the Commission set the fixed monthly charges?

These issues are examined individually below, with issues on which the Commission declines to accept the ALJ's recommendation discussed in greater detail.

IV. The Administrative Law Judge's Report

The Administrative Law Judge's Report is well reasoned, comprehensive, and thorough. The ALJ held three days of formal evidentiary hearings and four public hearings. He reviewed the testimony of 27 expert witnesses and related hearing exhibits. He reviewed the written comment submitted by a member of the public.

The ALJ received and reviewed initial and reply post-hearing briefs from the parties, as well as their proposed findings of fact and conclusions of law. He made some 667 findings of fact and conclusions of law and made recommendations on stipulated, settled, and contested issues based on those findings and conclusions.

The Commission has itself examined the record, considered the report of the Administrative Law Judge, considered the exceptions to that report, and heard oral argument from the parties. Based on the entire record, the Commission concurs in most of the Administrative Law Judge's findings and conclusions. On some issues, however, the Commission reaches different conclusions, as delineated and explained below. And on a few issues it provides technical corrections and clarifications.

On all other issues, the Commission accepts, adopts, and incorporates the ALJ's findings, conclusions, and recommendations.

FINANCIAL ISSUES

V. Accumulated Deferred Income Taxes

A. Introduction

1. Depreciation

Depreciation refers to the method of accounting for the presumed reduction in the value of an asset over time due to wear and tear, deterioration, or obsolescence. For regulatory and tax purposes, depreciation is designed to let a firm recover an investment in an asset over the asset's useful life by accounting for that investment as a stream of annual costs that can be offset against the firm's annual income.

When setting rates, the Commission seeks to permit a utility to recover its prudently incurred costs of service, including depreciation. The Commission generally prescribes *straight-line depreciation.*[9] For example, if a utility put into service an asset with an expected useful life of ten years, the Commission would design rates with the goal of letting the utility recoup its investment—including one-tenth of the asset's original book value—each year.

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[9] Minn. R. 7825.0800.

But to encourage capital investments, Congress authorizes many firms, for tax purposes, to depreciate assets faster than straight-line depreciation would allow. *Accelerated depreciation* permits a firm to record larger depreciation costs during an asset's early years, and smaller costs in later years, again with the goal of reaching zero by the end of the asset's useful life. And in 2015 Congress authorized *bonus depreciation* which further accelerates depreciation for tax purposes.[10]

2. Accumulated Deferred Income Taxes, Normalization, and Proration

Accelerated depreciation has the effect of deferring the payment of a portion of income taxes. The difference between the income taxes based on straight-line book depreciation and accelerated tax depreciation creates a deferred tax liability. A utility records each year's liability to an account known as *Accumulated Deferred Income Tax*.

If a utility seeks to gain the advantages of accelerated and bonus depreciation for tax purposes, federal law requires the utility to meet the requirements of *normalization*. This means that the utility's rates must reflect both the current income tax expense and the deferred income tax expense. In addition, the utility must apply the Accumulated Deferred Income Tax balance to reduce the amount of the utility's rate base, thereby reducing customer rates (all else being equal).[11] In effect, this process lets customers derive the benefit of the tax advantages of accelerated depreciation for an asset.

Rules adopted by the federal Internal Revenue Service (IRS) prescribe how to calculate the amount of the ADIT rate-base offset. In particular, when a utility calculates the amount of federal income tax to include in rates based on a future period, the IRS requires that the utility prorate projected accruals to ADIT to adjust for the period that these amounts are expected to be in the ADIT account.[12] In private letter rulings[13] the IRS has expressed its view that, to the extent that a rate is based on forecasted costs, it reflects a future period and thus the associated ADIT accruals must be prorated.

In this case, the size of the Otter Tail's accelerated and bonus depreciation, combined with its other operating costs, is greater than its current revenues. Consequently Otter Tail is reporting a net operating loss for federal tax purposes.

B. Positions of the Parties

1. The Department

The Department opposed Otter Tail's proposal to prorate its Accumulated Deferred Income Tax credit, which would increase the revenues to be recovered from Minnesota ratepayers by

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[10] *See* Protecting Americans from Tax Hikes (PATH) Act of 2015, Pub. L. No. 114-113, Division Q.

[11] *See* 26 U.S.C. § 168(f)(2), (i)(9); 26 C.F.R § 1.167(L)-1(h)(6).

[12] 26 C.F.R. § 1.167(l)-1(h)(6)(ii).

[13] The IRS may issue a private letter ruling (PLR) when a ratepayer asks how the IRS would apply the tax code to the ratepayer's specific circumstances. A PLR generally creates no legal precedent. *See* 26 U.S.C. § 6110(k)(3).

$763,973. The Department argued that historically utilities have not requested, and the Commission has not authorized, proration of these credits. The Department objected to the nature of the proration formula, which would result in deferred tax expenses not matching the change in the balance of Accumulated Deferred Income Tax.

While Otter Tail cited private letter rulings in which the IRS directed utilities to prorate their Accumulated Deferred Income Tax credits, the Department argued that those rulings pertained to other utilities' unique circumstances, not Otter Tail's circumstances. And while Otter Tail stated an intent to seek its own private letter ruling, the Department objected that Otter Tail's proposal provided no mechanism to refund over-collected sums if the Commission later learns that Otter Tail's legal analysis was in error.

2. The OAG

Noting the dispute between Otter Tail and the Department, the OAG proposed that the Commission reduce Otter Tail's depreciation expense to match the prorated level of the Accumulated Deferred Income Tax credit used for setting rates.

The OAG did not oppose Otter Tail's proposal to seek its own private letter ruling on this question, but expressed concern about prolonging the period of interim rates. Because interim rates tend to be higher than final rates, prolonging this period would prolong the time that ratepayers are paying excessive rates.

3. Otter Tail

Otter Tail argued in favor of prorating the Accumulated Deferred Income Tax adjustment credit. In support of its position, Otter Tail cited private letter rulings in which the IRS has directed other utilities that used forecasted test years to prorate their ADIT credits. Otter Tail acknowledged that its proposal would have the effect of increasing its revenue requirement by more than $763,000. But Otter Tail argued that the harm of failing to do so, if the IRS found the Company to be in violation of the tax code and the Company was no longer allowed to benefit from accelerated and bonus depreciation, would be substantially greater. If Otter Tail were required to use straight-line depreciation for tax purposes in this case, its Minnesota revenue requirement would have increased by $15.6 million.

But to further address the concerns raised by the parties, Otter Tail proposed to seek its own private letter ruling from the IRS. Ultimately the Department and the OAG supported this proposal.

C. The Recommendation of the Administrative Law Judge

The Administrative Law Judge recommended that the Commission adopt a proposal set forth by Otter Tail and summarized below:[14]

- Parties would address Otter Tail's Accumulated Deferred Income Tax issue in the same manner as they address any other issue, and brief it based on the information that the

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[14] ALJ's Report ¶ 321.

parties entered into the record. And the Commission would resolve the issues in this case according to the existing schedule—except for the Accumulated Deferred Income Tax issue. With respect to that issue, the Commission would defer judgment.

- Otter Tail convened a discussion among interested parties, as well as the Commission's staff, to draft a request for a private letter ruling from the IRS clarifying how the normalization rules would apply to Otter Tail's circumstances. Otter Tail sent the resulting request on December 28, 2016, and expects a reply within six months.

- The Commission would rule on this issue after the receipt of the IRS's private letter ruling, or after the expiration of some deadline such as August 31, 2017. The Commission's ruling, based on the then-available record, would provide the basis for establishing final rates and triggering any interim rate refunds.

- In the meantime, Otter Tail would agree to extend the duration of its case to provide time to resolve this Accumulated Deferred Income Tax issue, and would continue to charge interim rates.

No parties filed exceptions to the ALJ's Report on this issue—but at hearing, Otter Tail and the Department offered a refined version of this proposal. In particular, the parties proposed that if the IRS were to issue a ruling finding no need for proration—but issue it too late to be addressed in this docket—then Otter Tail would record its excess earnings due to proration into a separate account for potential refund in a later rate case or other proceeding. Also, the parties proposed setting July 31, 2017, as the final date for incorporating a private letter ruling into the record of this case, rather than August 31.

D. Commission Action

As the Administrate Law Judge observed, there is considerable uncertainty about whether federal law requires the proration of the Accumulated Deferred Income Tax credit for utilities setting rates on the basis of a forecasted test year.[15] Minnesota Statutes section 216B.03 directs the Commission to resolve doubts as to reasonableness in favor of the consumer. Arguably this would justify excluding Otter Tail's proration. But as Otter Tail noted, the interests of ratepayers are at risk whether the Commission authorizes the proration or not.

Given these risks, the Administrative Law Judge recommended that the Commission accept Otter Tail's proposal to await the IRS's private letter ruling on Otter Tail's query before resolving the rate case—and to extend the time for resolving the rate case to accommodate this delay. At hearing, while the parties recommended refinements to the Administrative Law Judge's proposal, no party objected to the idea in principle.

The Commission is concerned with delaying any appropriate relief for ratepayers bearing the cost of interim rates. But given the stakes involved, and the opportunity for reconciling any over-collection via the interim-rate refund or a future amortization of a regulatory liability, the Commission finds the parties' recommendation to be reasonable and appropriate to the

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[15] ALJ's Report ¶ 319.

circumstances. For these reasons, and based on discussions at the hearing, the Commission will approve Other Tail's proposal modified as follows:

For the present, the Commission will refrain from establishing final rates, and interim rates will remain in effect subject to refund. The Commission reserves the right to reopen the record of this proceeding to receive the parties' comments on the IRS's private letter ruling, and to set final rates and authorize a refund on the basis of the newly expanded record.

If at any time before August 1, 2017, the IRS issues a private letter ruling in response to Otter Tail's request, then the following will occur:

- Otter Tail must make a filing within 15 days of the ruling that would set forth the details of the ruling and estimate how implementing the ruling would affect rates.
- The Commission will establish a deadline for parties to file comments and replies on Otter Tail's analysis and proposal.

But if Otter Tail does not receive a private letter ruling from the IRS by July 31, 2017, then Otter Tail must do the following:

- By August 15, 2017, Otter Tail must file its detailed proposal for implementing final rates calculated on the basis of prorated Accumulated Deferred Income Tax.
- Otter Tail must record in its financial accounts a regulatory liability reflecting the difference between a revenue requirement including proration and a revenue requirement excluding proration.
- If the IRS ultimately issues a private letter ruling to Otter Tail that establishes that ratepayers paid excessive interim or final rates based on a misapplication of normalization requirements, then Otter Tail must submit a detailed proposal for addressing the regulatory liability. This proposal would be due as part of Otter Tail's initial filing in its next rate case, or at some earlier time designated by the Commission.

Finally, to minimize the chances of any last-minute disputes about this arrangement, the Commission will direct Otter Tail to file a preliminary report by July 1, 2017. This report would apprise the Commission of the status of Otter Tail's request for a private letter ruling, and summarize Otter Tail's understanding of how the parties will implement the process established above.

These procedures address potential contingencies associated with Otter Tail's request for an IRS private letter ruling, and provide an approach to each contingency that best promotes the public interest.

VI. MISO MVP Transmission Line Costs and Revenues

A regulated utility generally recovers its cost of providing regulated utility service through base rates, set in a rate case after consideration of all of the utility's costs and revenues. But the utility may also recover some costs via a separate mechanism called a *rider* or *automatic adjustment* *mechanism.* Specifically, the Legislature authorizes a utility to recover the cost of transmission facilities via base rates or a Transmission Cost Recovery Rider (TCRR).[16]

As with all other capital assets, if the transmission facilities generate additional revenues for the utility, those revenues would be used to offset other utility costs. This is called the "All-In" allocation. Where a utility's transmission facilities would serve multiple state jurisdictions, the costs of and revenues from the assets would be allocated among the jurisdictions according to some formula—for example, in proportion to each jurisdiction's energy consumption.

In this case, Otter Tail is building two transmission lines that will generate wholesale revenues that are expected to exceed their costs. Otter Tail proposed not to subject these capital costs to Minnesota retail ratemaking. As a result, Otter Tail would not recover the capital costs of these projects directly from Minnesota ratepayers via base rates or a rider, nor would Otter Tail share any of the revenues generated by these utility assets with Minnesota ratepayers. The Department and the Chamber opposed this proposal.

A. Introduction

1. MISO Multi-Value Projects (MVPs)

The Federal Power Act (FPA)[17] established the Federal Energy Regulatory Commission (FERC), and authorizes FERC to regulate "the sale of electric energy at wholesale in interstate commerce," including both wholesale electricity rates and any rule or practice "affecting" such rates.[18]

Under authority of the FPA and related rules, FERC has authorized the formation of regional transmission organizations.[19] One such organization is Midcontinent Independent System Operator, Inc. (MISO), which administers the high-voltage wholesale electric transmission grid in Minnesota and 14 other states, as well as the Canadian province of Manitoba. MISO evaluates the adequacy of the grid relative to the demand for transmission capacity, determines which generators may connect to the grid and when they may operate, and adopts tariffs establishing how the owners of transmission lines receive compensation from the parties who use them. The Commission authorized Otter Tail to join MISO in 2002, subject to conditions.[20]

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[16] Minn. Stat. § 216B.16, subd. 7b.

[17] 16 U.S.C. §§ 791 *et seq*.

[18] 16 U.S.C. §§ 824(b), 824e(a).

[19] 18 C.F.R. Pt. 35.

[20] *In the Matter of Otter Tail Power Company's Petition for Approval of Transfer of Operational Control of Transmission Facilities to the Midwest Independent System Operator*, Docket No. E-017/PA-01-1391, Order Authorizing Transfer with Conditions (May 9, 2002); *Otter Tail Power Co.*, 97 FERC ¶ 61,226 (2001); Otter Tail Power Co., 98 FERC ¶ 62,218 (2002).

When a utility's transmission facility comes within the scope of MISO's tariffs, the utility must pay MISO's tariffed rate to use its own transmission line (or any other transmission line operated by MISO). But the utility also receives payments that MISO collects from the other users of the utility's transmission line. MISO designs its tariffs to permit transmission owners to recover the costs of their projects through usage payments, including MISO's return on equity as authorized by FERC.

Generally MISO tariffs provide that the parties who benefit from a line pay the owners of the lines they use. But certain projects have such significant costs, and system-wide benefits, that MISO provides for their costs to be recovered from all of MISO's load-serving entities—and by extension, from their nearly 30 million retail customers—based on each entity's share of energy consumed within the MISO footprint. MISO calls these projects Multi-Value Projects (MVPs).

Because Otter Tail customers consume 0.98 % of the energy sold within MISO, MISO bills Otter Tail 0.98 % of the cost of all MVP projects. Otter Tail bears these costs in addition to the capital costs it bears to build its own transmission facilities. Otter Tail generally recovers all these costs via its Transmission Cost Recovery Rider or its base rates.

In addition, Otter Tail receives revenues for the use of MVP transmission facilities that it owns according to the MISO tariff's terms. Historically, Otter Tail also reflects these revenues in its Transmission Cost Recovery Rider or its base rates.

2. Otter Tail's MVPs at Issue

The parties disagree about the appropriate allocation of the cost and revenues of two MVPs that Otter Tail is building near Big Stone, South Dakota, collectively called the Big Stone Access Transmission Lines (BSAT Lines). Otter Tail owns a half interest in the Big Stone–Brookings Line, and a half interest in the Big Stone–Ellendale Line.

B. Positions of the Parties

1. Otter Tail and the OAG

For purposes of this rate case, Otter Tail proposed to remove the costs and revenues of its BSAT Lines from consideration in this ratemaking docket.

This proposal would have a number of financial consequences for Otter Tail's ratepayers and shareholders. Otter Tail would not seek to recover the lines' capital costs directly via base rates or rider—but would continue recovering the costs for the use of the new lines under the MISO tariff, just as before. And Otter Tail would not share any revenues it would recover under the MISO tariff for the use of its new transmission lines. This would benefit Otter Tail's shareholders by permitting them to retain earnings calculated on the basis of MISO's higher return on equity, rather than having those revenues assigned to the state jurisdictions in which Otter Tail operates to offset the utility's other costs.

Otter Tail acknowledged that it is seeking different ratemaking treatment for the BSAT Lines than for Otter Tail's other facilities, but argued that these lines were distinct from Otter Tail's other lines by virtue of their cost. This cost disparity, Otter Tail argued, reflects the idea that the BSAT Lines were not built to serve Otter Tail's customers specifically, but were built as MVPs to serve the MISO grid as a whole—and therefore warrant different regulatory treatment.

In addition, Otter Tail argued that it was justified in not seeking to recover the cost of its BSAT Lines via the TCRR because it had already made such a request and was denied. Otter Tail added that neither the Department nor the Chamber recommended recovering the cost of the BSAT Lines via the TCRR in any of Otter Tail's last three TCRR cases.

Otter Tail opposed the idea of accounting for the costs and revenues of the BSAT Lines in this rate case using All-In allocation. According to Otter Tail, FERC authorized a higher return on equity to provide incentives for investors to finance more transmission lines, but All-In allocation would frustrate this purpose by using this incentive to compensate ratepayers rather than investors. Otter Tail argued that the Department and the Chamber were merely seeking to arbitrage the differences between the federal and state jurisdictions to permit ratepayers to gain an unmerited advantage at the expense of shareholders. Otter Tail argued that FERC jurisdiction bars a state regulator from setting rates in a manner that would preclude a utility from receiving and retaining FERC-approved costs and revenues.

Otter Tail rejected the idea that it should have established a separate affiliate in order to justify according different treatment to the BSAT Lines than to its other assets. Otter Tail noted that jurisdictional allocations are a common feature of ratemaking and Otter Tail has never needed separate legal entities to make such allocations in the past.

In any event, Otter Tail argued that the circumstances of the BSAT Lines are sufficiently different from the circumstances under which the Commission has approved the use of All-In allocation as to justify a different result in this case.

The OAG agreed with Otter Tail that the BSAT Lines should not be subject to All-In allocation. The OAG argued that such treatment would be most consistent with traditional principles of cost allocation and separation.

2. The Department and the Chamber

The Department and the Chamber opposed Otter Tail's proposal to exclude consideration of the BSAT Lines from this rate case. Instead, they recommended that the Commission continue its practice of approving an All-In allocation, whereby Minnesota's share of a project's costs and revenues are considered with all other costs and revenues when setting rates.

The Department's recommendation differed somewhat from the Chamber's. The Department recommended that the Commission direct Otter Tail to incorporate the costs and revenues of its BSAT Lines into its currently pending TCRR docket.[21] In contrast, the Chamber recommended

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[21] *In the Matter of the Petition of Otter Tail Power Company for Approval of its Transmission Cost Recovery Rider Annual Adjustment*, Docket No. E-017/M-16-374.

that the Commission direct Otter Tail to incorporate the BSAT Lines into the TCRR retroactive to 2014, the first year that a revised TCRR statute provided for recovering the cost of out-of-state facilities.

The Chamber argued that, in effect, Otter Tail is seeking to treat its investment in the BSAT Lines as if it were an unregulated affiliate, unaffected with a duty to serve in the public interest. The Chamber noted that if Otter Tail had intended to achieve that outcome, it could have made the appropriate filings before it began to pursue the BSAT Lines project. This would have provided an opportunity for all parties to ensure that the costs of the regulated and unregulated operations were kept separate, so that ratepayers would not inappropriately subsidize shareholders. But Otter Tail never did that. To the contrary, in 2012 Otter Tail petitioned to recover the cost of these same transmission facilities via the TCRR. According to the Chamber, this fact undermines any argument that Otter Tail acted in reliance on the idea that it would be allowed to account for its costs and revenues as if they were separate from the rest of Otter Tail's regulated operations.

The Department and the Chamber noted that Otter Tail had a history of seeking to assign assets to FERC's jurisdiction that would generate substantial wholesale revenues (MISO Schedule 26A revenues). They noted that the Commission had precluded this practice in the past, requiring use of All-In allocation instead.

The Department and the Chamber argued that Otter Tail overstated the distinctions between Otter Tail's investment in the BSAT Lines and its investment in other assets recovered via All-In allocation. Both parties noted that the BSAT Lines, like Otter Tail's other transmission lines, would serve Otter Tail's retail customers. And the Department denied that the size of an investment should alter the ratemaking treatment for the investment.

Otter Tail argued that it was the Department and the Chamber who were advocating an inconsistent position, in that they refrained from advocating All-In allocation for the BSAT Lines during any of the three prior dockets to adjust Otter Tail's TCRR. But the Department rejected this assertion. The Department noted that it files comments in response to utility petitions for Commission approval. When a utility declines to seek Commission approval—for example, declining to seek cost recovery for the BSAT Lines via the TCRR—then it is not surprising that the Department would not file comments on that matter.

While it might appear that Otter Tail's retail customers would benefit from having to bear only 0.98% of the BSAT Lines' cost, the Chamber emphasized that the loss of the associated revenue the lines generate would offset this benefit. Moreover, the Chamber noted that Otter Tail's ratepayers would bear 0.98% of the cost not only of the BSAT Lines, but of all 17 of MISO's MVPs. Otter Tail's customers must bear the cost of these facilities—even remote facilities that might seem to provide little benefit for Otter Tail's customers—as well as bear various administrative charges. Consequently, those same ratepayers should derive the full benefit of the few MVPs that their utility actually owns, to help offset those other MISO costs, the Department and the Chamber argued.

If the Commission were to decline to order Otter Tail to recover the cost of the BSAT Lines via the TCRR, the Department would recommend that the Commission rescind its authorization for Otter Tail to use this rider, and instead have all transmission costs recovered through base rates following a full rate case. This remedy would eliminate disputes about which projects should be recovered via the TCRR and which should not.

C. The Recommendation of the Administrative Law Judge

The ALJ largely concurred with Otter Tail and the OAG.

The ALJ concluded that FERC has exclusive jurisdiction over the transmission of electricity in interstate commerce, and that MISO acted within that jurisdiction when it established a relatively high return on equity as a means to encourage investment in certain transmission facilities. According to the ALJ, state policies that would undermine the operation of these federal policies are preempted. Because the proposals of the Chamber and the Department would reduce Otter Tail's financial incentive to invest in the BSAT Lines, and similar lines in the future, the ALJ concluded that the Commission should reject them.

Furthermore, the ALJ concluded that the TCRR statute does not authorize the Commission to compel a utility to recover the cost of any given transmission project via the rider.

Finally, the ALJ concluded that the Department's alternative proposal to eliminate Otter Tail's TCRR would encounter the same problems as its initial proposal, because it would undermine the financial incentives created by MISO. Consequently the ALJ recommended that the Commission reject that proposal as well.

Instead, the ALJ recommended that the Commission authorize Otter Tail to treat its BSAT Lines as subject to federal jurisdiction.[22]

D. Commission Action

The Commission respectfully disagrees with the ALJ's recommendation regarding the jurisdictional allocation of the BSAT lines. The Commission concurs with the Department for the reasons set forth below, and will require Otter Tail to include the BSAT Lines in the Company's existing TCRR.

1. Filed Rate Doctrine Claim

There is no disagreement that Otter Tail is a public utility that is adding the BSAT Lines to its system as utility plant that will be used and useful in the provision of electric service to its retail customers in Minnesota. Parties disagree, however, about the boundaries between federal and state ratemaking jurisdiction with respect to those lines. But in 2016 the U.S. Supreme Court provided a modicum of clarity when it found that the
Federal Power Act authorizes FERC—

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[22] ALJ's Report ¶¶ 266-94.

> to regulate “the sale of electric energy at wholesale in interstate commerce,” including both wholesale electricity rates and any rule or practice “affecting” such rates. [16 U.S.C.] §§ 824(b), 824e(a). But the law places beyond FERC’s power, and leaves to the States alone, the regulation of “any other sale”—most notably, any retail sale—of electricity. § 824(b).[23]

Otter Tail argued that the Commission’s All-In allocation of the BSAT Lines would violate the filed-rate doctrine, which requires state commissions to pass through FERC mandated wholesale rates. But as the Department and the Chamber noted, All-In allocation does not decline to pass through MISO’s MVP rates. To the contrary, it includes those rates, as well as the associated revenues, when setting Otter Tail’s retail rates. And, as noted above, rates for the retail sale of electricity remain within the jurisdiction of the states—and the states alone.

Accepting Otter Tail filed rate doctrine claims would also result in “unbundling” Minnesota’s electric retail service rates. In Minnesota, retail rates bundle together all the costs of a utility providing retail and wholesale electric services—generation, transmission, and distribution—in a single price set by the Commission. In effect, Otter Tail is arguing that the federal filed rate requires unbundling a portion of Otter Tail’s transmission cost—from the rest of its bundled generation, transmission, and distribution retail service costs. Such an application of the filed-rate doctrine would be inconsistent with FERC’s own decision not to exercise its authority to unbundle state retail rates and assert jurisdiction over the retail transmission costs contained in those rates.[24]

Consequently the Commission rejects the conclusion that the filed-rate doctrine precludes the Commission from setting retail rates for bundled retail electric service using All-In allocation.

2. Continuity Between the BSAT Lines and Other Otter Tail Facilities

Otter Tail argues that the unique role of its BSAT Lines as MVPs justifies atypical regulatory treatment. And indeed, these lines are subject to MISO’s MVP tariffs. But they are not Otter Tail’s only lines subject to MISO tariffs.

Some of Otter Tail’s larger transmission lines come within FERC’s jurisdiction, even if they are not MVPs—for example, the CapX 2020 Fargo and Bemidji transmission lines. Otter Tail pays the MISO-tariffed rate to use these lines, and receives the MISO-prescribed revenues that MISO collects from transmission users on Otter Tail’s behalf. Notwithstanding the role of federal entities in this arrangement, no party has objected to the Commission taking both these costs and these revenues into account as part of this rate case.

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[23] *FERC v. Elec. Power Supply Ass’n*, 136 S.Ct. 760, 766 (2016).

[24] *See New York v. FERC*, 122 S.Ct. 1012, 1020, 1026 (2002) (noting that FERC specifically declined in Order No. 888 to use its authority under the FPA to require unbundling of state retail rates due to the “difficult jurisdictional issues” it would raise).

Moreover, Otter Tail already has an operating MVP: the CapX 2020 Brookings–Hampton 345 kV transmission line. This line is explicitly subject to MISO's MVP tariffs, yet no party has objected to the Commission incorporating both its costs and revenues into rates. Specifically, Otter Tail incorporates theses costs and revenues into its Minnesota retail rates through the operation of its TCRR. This fact undermines the claim that the BSAT Lines occupy a unique regulatory position.

The argument is further eroded by the fact that Otter Tail owns only half of its Big Stone–Brookings MVP line, and the party who owns the other half—Northern States Power Company d/b/a Xcel Energy (Xcel)—employs All-In allocation to recover its share of the line's costs via Xcel's own TCRR. Thus, to approve Otter Tail's proposal, the Commission would have to conclude that Otter Tail's ratepayers are not entitled to a portion of a transmission line's revenues to help offset the jurisdictional portion of the line's costs—when Xcel has reached the opposite conclusion about its own ratepayers.

In sum, the Commission is not persuaded that Otter Tail's interest in the BSAT Lines warrants regulatory treatment that differs from the treatment accorded to other projects in FERC's jurisdiction.

3. Arbitrage

Otter Tail argues that to subject its BSAT Lines to All-In allocation would reflect a wrongful arbitrage by taking the higher return on equity offered by MISO and allocating it to the benefit of Otter Tail's retail customers in Minnesota. The Commission shares Otter Tail's concern for arbitrage, but does not agree with Otter Tail's analysis or conclusion.

Regulatory arbitrage arises when a party seeks to take strategic advantage of price differences that arise within different regulatory environments. This Commission has addressed the problem in the context of telecommunications.[25] The remedy for arbitrage is to ensure, as far as possible, that a consistent regulatory policy prevails.[26]

In this case, Otter Tail has sought to assign the BSAT lines to the FERC's jurisdiction, contrary to the assignment of all of its other transmission lines, to maximize advantage for its shareholders at the expense of its ratepayers. In contrast, the Department and the Chamber have proposed that, for purposes of state ratemaking, Otter Tail's projects be subject to a uniform regulatory regime—All-In allocation. The Department's approach, which the Commission adopts, precludes arbitrage inherent in Otter Tail's proposal.

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[25] *See*, e.g., *In the Matter of Intercarrier Compensation Reform Required by [Federal Communications Commission] Order*, Docket No. P-999/M-12-356, Order Establishing Procedures for Revising Intrastate Access Rates (May 24, 2012) (addressing a disparity in the regulatory treatment of landline and wireless telecommunications, and between long-distance and local calls).

[26] *Id*. (adopting polices to reduce the disparities in the regulation of land-line and wireless telecommunications).

4. Transmission Cost Recovery Rider

In addition, Otter Tail argued that the Commission cannot compel the Company to recover any specific costs via the TCRR.

Otter Tail argued that the Commission already had the opportunity to authorize recovery of the BSAT Lines via the TCRR, but the Commission denied Otter Tail's petition for authorization to use the rider. But this argument is unpersuasive for two reasons. First, Otter Tail withdrew its request to recover the cost of the BSAT Lines before the Commission ever had the opportunity to rule on it.[27]

Second, Otter Tail initially sought to use the TCRR to recover the costs of its BSAT Lines in 2012, the authorizing statute did not provide for recovering the cost of out-of-state projects. That is why Otter Tail withdrew its initial petition. But in 2013 the Minnesota Legislature changed the statute to authorize such recovery.[28] The revised statute now authorizes the Commission to approve, reject, or modify a tariff that:

> allows the utility to recover charges incurred under a federally approved tariff that accrue from other transmission owners' regionally planned transmission projects that have been determined by the Midcontinent Independent System Operator to benefit the utility or integrated transmission system. These charges must be reduced or offset by revenues received by the utility and by amounts the utility charges to other regional transmission owners, to the extent those revenues and charges have not been otherwise offset; [and]
>
> allows the utility to recover on a timely basis the costs net of revenues of facilities approved by the regulatory commission of the state in which the new transmission facilities are to be constructed and determined by the Midcontinent Independent System Operator to benefit the utility or integrated transmission system….[29]

This revised statute clearly provides for recovery of MISO-approved MVPs—and clearly provides for considering a project's revenues as well as costs.

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[27] *In the Matter of Otter Tail Power Company's Request for Determination that Transmission Investments are Eligible for Recovery through the Company's Transmission Cost Recovery Rider,* Docket No. E-017/M-12-514, Order Approving Transmission Cost Recovery Rider Eligibility for Three Projects, at 1 (March 15, 2013).

[28] *See* 2013 Minn. Laws, ch. 85, art. 7, § 1.

[29] Minn. Stat. § 216B.16, subd. 7b(b)(2) and (3).

Otter Tail correctly observes that the TCRR statute states that a utility must request establishment of a TCRR mechanism before the Commission may implement one. But Otter Tail has already asked, and received, permission to establish a TCRR.[30]

Ultimately, when a utility files a general rate case under Minnesota Statutes Section 216B.16, it invites the Commission to evaluate the utility's costs and revenues related to regulated utility services. Thereafter, the Commission exercises its authority to rule on a utility's revenues and costs, and the means by which the utility will match the one with the other. Under the statute, the Commission may authorize a utility to recover its prudently incurred costs via base rates and/or a variety of riders, including the TCRR—assuming the utility has requested to add such a rider to its tariffs.

Because the Federal Power Act preserves the Commission's jurisdiction over retail electric service, and the record provides no sufficient basis to discriminate between the ratemaking treatment accorded to the BSAT Lines and Otter Tail's other transmission lines, the Commission will continue to apply All-In allocation uniformly. Because the BSAT Lines had not yet become used and useful during the test year of the current rate case, the Commission will not incorporate the costs and revenues of those facilities into Otter Tail's base rates in this proceeding. But riders permit rate adjustments to reflect certain changes in a utility's costs and revenues accruing between rate cases.

The Commission will therefore direct Otter Tail to amend its petition in the currently pending TCRR docket to incorporate into its filing the costs and revenues related to its BSAT Lines. In the interest of simplicity, however, the Commission will decline the Chamber's proposal to direct Otter Tail to file a TCRR rate retroactive to the earliest point it might have taken effect. The Commission's policy will provide both ratepayers and shareholders with the consistent regulatory treatment that has guided the Commission's past decisions—All-In allocation, matching all of a utility's costs within the state with all of the related revenues.

VII. Corporate Aircraft Expense

A. Introduction

Otter Tail's service territory (70,000 square miles) is rural with limited commercial air service. The Company owns a 1987 turboprop aircraft, which it used some 48 times during 2015, mainly for trips between the Fergus Falls headquarters and the three state capitals where it is subject to state regulatory proceedings. The Company seeks 100% of the jurisdictional share of costs for owning and operating the aircraft ($117,453).

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[30] *In the Matter of Otter Tail Power Company's Request for Approval of a Transmission Cost Recovery Rider Including the Proposed 2010 Transmission Factor*, Docket No. E-017/M-09-881, Order Establishing Transmission Cost Recovery Rider and Approving Costs for Recovery (January 28, 2010).

B. Positions of the Parties

1. Otter Tail

Otter Tail argued that, in compliance with the Commission directive in its last rate case, it had provided a cost/benefit analysis that would justify aircraft expense recovery of over 75%. Otter Tail explained that it used a “fly versus drive” tool (similar to one used by the Minnesota Department of Transportation) to justify each of the aircraft-expense transactions. The Company based its 2016 test-year amount for aircraft expense on a three-year average of costs during 2012, 2013, and 2014. The Company calculated that if the aircraft had not been used, the driving costs for the 48 flights would have been $311,621 (total)[31] compared with the total flying costs of $302,577.

2. The OAG

The OAG argued that $78,693 in requested expenses should be disallowed. The OAG asserted that the Company’s proposal for recovery of the fixed costs lacked sufficient support in the record. The OAG calculated that the Company’s invoiced flight amounts for 2015, adjusted to reflect known changes for 2016, were $82,878 ($38,760 for the Minnesota jurisdiction)—far less than the requested amount. The OAG calculated that the $117,453 requested is over 200% higher than the Minnesota-jurisdictional amount.

Finally, the OAG requested that, in Otter Tail’s next rate case, the Commission require the Company to provide more support to justify its recovery of fixed costs.

C. Report of the Administrative Law Judge

The Administrative Law Judge found that Otter Tail’s ownership and use of its aircraft is reasonable and necessary to the provision of utility service. He also found that the Company’s cost-benefit analysis supported 100% of the jurisdictional share of the ownership and operational costs of the aircraft for the 2016 test year. Finally, he found that use of the corporate aircraft cost ratepayers less than if Company employees were to travel by car.

D. Commission Action

The Commission concurs with the Administrative Law Judge and adopts his findings, conclusions, and recommendations on this issue. The Commission agrees that the Company complied with the Commission’s directive in its last rate case and has justified 100% of the airplane expenses in this matter. The Company has shown a clear business purpose for each of the trips for which it seeks expense recovery and that the efficiencies the Company gains (less travel time, lower travel costs, and not needing to hire additional staff) continue to be substantial.

In recognition of the OAG’s concerns, and pursuant to their request, the Commission will order Otter Tail to provide more detailed, granular information of aircraft-related fixed costs and avoided costs of driving in future rate cases.

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[31] The Company’s analysis did not include the avoided costs of additional vehicles, incidental costs such as meals, and having to hire additional employees.

VIII. Pension Asset and Other Post-Employment Benefit Liabilities

A. Introduction

Otter Tail proposed to include pension and other post-employment benefit amounts in rate base. The Department recommended that both Otter Tail's prepaid pension asset and its other post-employment benefit (OPEB) liabilities be excluded from the 2016 test-year rate base, which would increase the test-year rate base by $3,777,217. The OAG recommended that the only prepaid pension asset be excluded from test-year rate base.

B. Positions of the Parties

1. The Company

Otter Tail argued that prepaid pension asset should be included in rate base for three reasons:

- The prepaid pension asset provides substantial benefits to customers, including a reduction in pension expenses;
- Including the prepaid asset in rate base is consistent with standard regulatory treatment of investor funded prepaid expenses; and
- Including the prepaid pension asset in rate base is consistent and symmetrical with the treatment that the Company has applied to Financial Accounting Standards 106 and Financial Accounting Standard 112 liabilities.[32]

The Company explained that its prepaid pension asset was calculated as the excess of cumulative contributions over cumulative actuarially calculated pension expenses. The Company stated that it has contributed some $80 million (total company), $40.4 million (Minnesota), to its pension trust since 2009. The Company further argued that approximately $55 million of its contributions were not required under the Employee Retirement Income Security Act (ERISA).[33]

The Company disagreed with the Department's recommendation to exclude both the prepaid pension asset and the OPEB liabilities from rate base, arguing that the Company's approach is consistent with ratemaking standards and the Commission's approach in two Xcel Energy rate cases. Further, Otter Tail asserted that quantified and direct customer benefits of approximately $241,000 were shown in the 2016 test year from the prepaid pension asset, when considering both the reduced pension expense and the Company's recovery of a return on the prepaid pension asset.[34]

Finally, the Company argued that if it is not allowed to earn a return on its prepaid pension asset, then consistency and standard Commission practice require the asset to be excluded from the calculation of the pension expense.

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[32] Beithon Direct, at 28 – 29.

[33] Beithon Rebuttal, at 10.

[34] *Id.* at 9, 13.

2. The Department

The Department disagreed with rate-base treatment of these accounts for the following reasons:

- The concept of calculating the difference between plan contributions and actuarially calculated pension expense is an obsolete concept no longer used under Generally Accepted Accounting Principles (GAAP);
- It is unreasonable to allow Otter Tail to place a prepaid pension asset, as defined by outdated GAAP guidance, into rate base to earn a guaranteed return while the pension plan is actually underfunded; and
- The prepaid pension asset is different from typical prepaid assets because it does not necessarily represent cash outlay by the Company, nor does it depreciate or amortize over time like other assets.

Financial reporting guidance for defined-benefit plans has changed over the years and is now consolidated in Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC) 715, which the Department relied on. This is the current financial standard, and requires that companies with defined-benefit retirement plans report the overfunded or underfunded status of their plans as a net asset or net liability on the company's balance sheet. Treatment under ASC 715 contrasts with the prior treatment of these assets by the FASB, where the funded status of a company's pension assets and pension obligations was allowed to be reported as a footnote to the company's financial statements.

The Department emphasized that it would be unreasonable to place the pension asset balance into test-year rate base, and to pay shareholders a return on the amount, where the asset balance is not solely investor-supplied funds.[35] The Department explained that quantifying the reduction in pension expense due to increases in the expected return on the pension trust does not change the fact that investment earnings, which are *not* funds contributed by shareholders, are included in the prepaid pension asset.

The Department explained that it would also be unreasonable to guarantee the Company a return on its proposed prepaid pension, while providing no guarantees to ratepayers and leaving them obliged to pay any shortfalls that might occur in the future.

The Department argued that, although Xcel Energy may have used a similar approach to prepaid pension in recent rate cases, the Commission has not decided this issue based on a fully litigated record as to this aspect of pension costs, due to the voluminous numbers of issues in those cases. Further the Department argued that the 2015 Minnesota Energy Resources Corporation (MERC) rate case is instructive, as Otter Tail's proposed rate-base treatment of pension and Other Post-Employment benefits was not significantly different from MERC's. In that case, the Commission denied rate base treatment of MERC's prepaid pension asset.

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[35] Byrne Summary, at 2; Byrne Surrebuttal, at 37.

Finally, the Department recommended excluding the accrued OPEB liabilities from rate base, because those balances are temporary and may go up or down, depending on funding, market conditions, or amendments to the pension plan.

3. The OAG

The OAG opposed including the prepaid pension asset in rate base. The OAG also recommended that the Commission not allow any contributions above the ERISA minimum funding levels to earn a return.

C. Recommendations of the Administrative Law Judge

The Administrative Law Judge found that the test year rate base should exclude the prepaid pension asset and OPEB liabilities, and that the net financial effect of these adjustments is an increase to Otter Tail (Minnesota) rate base by $3,777,217.

The ALJ reasoned that the opportunity to generate an expected return on assets, which reduces corporate liabilities under ERISA, is itself a meaningful return to shareholders. Further, the ALJ stated that the pension asset is unlike other familiar items included in rate base. The ALJ stated that "teasing out which fraction of the asset is traceable to investor-supplied funds from that which follows from changes in actuarial experience, or marketplace returns, is very problematic," as the size of the asset fluctuates from year-to-year—even in years when no pension contributions are made by the Company.[36]

D. Commission Action

The Commission concurs with the Administrative Law Judge and the Department that Otter Tail has not justified rate-base treatment of pension and other post-employment regulatory benefits in this case.

Otter Tail recovers its allowable pension expense from ratepayers, and is not denied recovery of this operating cost. Further, as the Department explained, pension-plan assets and benefit obligations go up and down, depending on funding or market conditions. The balances in the prepaid pension asset are temporary, and fundamentally different from typical rate-base assets on which the Company earns a return on investment. In fact, as the Department explained, Otter Tail's pension is actually underfunded.[37]

Nor does the Commission find the treatment of pension assets in Xcel Energy's recent rate cases to be persuasive or precedential. The parties did not specifically litigate the question of whether a company's pension asset is properly included in rate base.[38]

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[36] ALJ's Report ¶ 343.

[37] Byrne Surrebuttal, at 30.

[38] Byrne Summary, at 2.

The Commission finds, however, that the treatment of this question in MERC's 2015 rate case is instructive.[39] In MERC's 2015 rate case the Commission found that prepaid pension asset should not be included in rate base, due to the fundamental difference between pension assets and other assets. Accordingly, the Commission will exclude prepaid pension asset and OPEB liabilities and associated ADIT from test-year rate base.

IX. Discount Rates for Pension and Other Post-Employment Benefit Options

A. Introduction

Otter Tail and the Department agreed to update the expected return on assets for qualified pension to 7.75% and update the census data for qualified pension, retiree medical, and Long Term Disability (LTD) medical expense to January 1, 2016.[40] Otter Tail and the Department also agreed to use a five-year average to determine the discount rates to calculate pension and OPEB. The parties disagreed, however, on which years to average. Otter Tail recommended use of a five-year average, spanning 2012 – 2016; the Department recommended calculating the average based upon the years 2011 – 2015.

B. Positions of the Parties

1. The Department

The Department recommended that Otter Tail's test-year pension and OPEB expenses be calculated using the five-year fully historical 2011 – 2015 average discount rate—5.06% for pension, and 4.87% for retiree medical expenses and long-term disability medical expenses. The effect of the Department's recommendation reduces qualified Minnesota jurisdictional pension expense for Otter Tail by $936,931 and increases OPEB expenses by $517,702

The Department argued that 2016 is an unaudited financial year, and based on forecasted test year costs, not on known, historical data. Further, the Department asserted that the Company's proposed discount rate, based on the years 2012 – 2016, does not follow recent Commission decisions on this issue. The Department disputed Otter Tail's reasoning that, because the pension and OPEB discount rates were based on the same financial standards (FAS 87, 106, and 112) as the discount rates for all prior years, that there is no basis to conclude that the 2016 discount rates are any less reliable than in previous years.

Finally, the Department argued that in several recent rate cases, the Commission has used the same methodology it has recommended, based exclusively on historical five-year rates.

2. Otter Tail

In rebuttal testimony, Otter Tail accepted the use of a five-year average to determine the discount rates to calculate pension and OPEB expense. Otter Tail, however, proposed to use the average of 2012 – 2016 discount rates, arguing that the five-year average should include the most current

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[39] *In the Matter of the Application of Minnesota Energy Resources Corporation for Authority to Increase Rates for Natural Gas Service in Minnesota*, Docket No. G-011/GR-15-736, Findings, Conclusions, and Order, at 11 (October 31, 2015).

[40] ALJ's Report ¶ 265; Byrne Surrebuttal, at 7–8.

information available, which includes the 2016 test year. The Company asserted that the 2016 data is more appropriate than six–year old data that reflects economic conditions in 2011, which were quite different from 2016.[41]

Otter Tail recommended adjustment of the 2016 test-year expense to reflect:

- The updated earned return on assets from 7.50 to 7.75% and updated January 1, 2016 census information; and
- The 2012 – 2016 average discount rates of 4.81% for pension and 4.63% for OPEB.

Otter Tail argued that the 2012 – 2016 five-year averages should be used to set rates for the test year because they are more representative and forward-looking as to costs and economic conditions than the Department's 2011 – 2015 five-year average. The Company argued that the Department's average uses old and unrepresentative data, considering that the 2011 OPEB discount rate of 5.75% ranges from 65 to 155 basis points higher than any other OPEB discount rate since that time. Otter Tail also argued that its five-year average buffers short-term variation in current economic conditions.

Finally, Otter Tail argued that in the 2013 Xcel rate case, the test year was included in the five-year average adopted by the Commission. The Company argued that none of the other 2013 or 2015 rate cases relied on by the Department raised the issue of whether to include the test year in the five-year period used to calculate the discount rate.

C. The Administrative Law Judge's Report

The ALJ acknowledged that the issue is not free from doubt, but concluded that the term "historical average" should refer to actual data from prior years and not test-year projections. The ALJ therefore adopted the Department's recommendation to use a historical 2011 – 2015 discount rate, resulting in a 5.06% discount rate for pension, and a 4.87% discount rate for post-retirement medical expenses (FAS 106) and long-term disability expenses (FAS 112).

D. Commission Action

The Commission accepts Otter Tail and the Department's agreement to update the expected return on plan assets for qualified pension to 7.75% and update the census data for qualified pension, retiree medical, and LTD medical expense to January 1, 2016.

The Commission respectfully disagrees, however, with the ALJ's discount-rate recommendations for pensions and OPEB. The Commission will instead adopt certain revised findings and conclusions as set forth below and in the ordering paragraphs.

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[41] Beithon Rebuttal, at 6.

The ALJ recommended adopting the Department's position to use the 2011 – 2015 period to establish average discount rates used to calculate pension and OPEB expense because it uses only actual data from prior years and not test-year projections. The Commission finds, however, that the Company's proposal to use the average for 2012 – 2016 also uses only actual data, because the 2016 discount rates are not projections, but the actual rates established as of December 2015, used by Otter Tail to calculate the 2016 pension and OPEB expense.[42]

The Commission finds that it is more appropriate to use the most representative average data to determine rate-case costs. The Commission finds that the 2016 actual data better reflects current conditions than the 2011 actual data, which are outliers—2011 economic conditions and discount rates were considerably different from more current economic conditions and discount rates.

The Commission therefore will allow Otter Tail to use the 2012 – 2016 five-year average discount rates of 4.81% to calculate test-year pension expense, and 4.63% to calculate test-year OPEB expenses. The Commission will also require Otter Tail to make the correct adjustment to total test-year pension and OPEB expenses, including those in O&M expenses and those that are capitalized.

X. Energy Rider and TailWinds Program

A. Introduction

The Tailwinds Program is Otter Tail's wind-generated energy program that allows customers to purchase 100-kilowatt-hour blocks of renewable energy at a fixed rate per block each month. Otter Tail has purchase power agreements (PPAs) with two small wind providers designated to serve the Tailwinds program. Under the PPA terms, Otter Tail purchases 100% of the energy generated by the specific wind turbines.

Otter Tail excludes the amount of energy purchased from the program from incurring monthly energy adjustment rider (or fuel clause adjustment rider) charges. The program is currently undersubscribed.[43]

B. Positions of the Parties

1. Otter Tail

Subscription to the program was approximately half the designated output from the facilities in 2015. Because the Company excludes the entire amount of the two PPAs from the fuel clause calculations, it is not recovering the unsubscribed portion of the PPAs.

The wind energy (kWh) produced by the two generators in excess of the subscriptions serves as a contribution to the energy requirements of all Otter Tail customers, but is reflected in the Company's energy-cost calculations at zero cost. The Company proposed to revise Section 13.01 of its Electric Rate Schedule so that non-TailWinds customers pay for wind energy credited to them through the fuel clause.

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[42] Beithon Rebuttal, at 4–7.

[43] Tommerdahl Rebuttal, at 49.

Otter Tail argued that its request is reasonable. The Company argued that the Commission's approval of Xcel Energy's Windsource program provides support for its request.[44]

2. The Department

The Department opposed the Company's request for recovery of the unsubscribed costs of the TailWinds program PPAs. The Department argued that the Commission's approval of recovery for Xcel's Windsource program is not relevant, because Xcel had established that the PPA for that program was cost-effective and reasonable. The Department recommended denying the Company's request, because Otter Tail provided no information demonstrating that the TailWinds PPAs are cost-effective or reasonable.

3. The Chamber of Commerce

The Chamber of Commerce also objected to the Company's proposal to recover the unsubscribed portion of the PPAs from other customers, and recommended that the Commission deny recovery through the fuel clause. The Chamber argued that the purpose of the PPAs was to sell renewable energy to customers willing to pay a premium for renewable energy.

C. Recommendations of the Administrative Law Judge

The ALJ noted the significant differences in the record for Xcel's Windsource PPA and the record in this matter. In the Xcel docket, there was a thorough assessment of program costs, operational risks, and curtailment provisions. The ALJ found that in this record, there was not the same detail or assurance that the PPAs are cost effective and in the best interest of ratepayers. The ALJ recommended denial of Otter Tail's proposal to charge unsubscribed energy costs to non-enrolling customers through the fuel clause.

D. Commission Action

The Commission concurs with the Administrative Law Judge's findings, conclusions, and recommendations, and will deny Otter Tail's proposal to recover the unsubscribed energy costs associated with the TailWinds program from non-enrolling customers through the Fuel Clause. Otter Tail did not provide sufficient evidence to establish that the PPAs for the TailWinds program were cost effective and in the best interests of customers.

XI. Reagents and Emissions Allowances – Fuel Clause Adjustment

A. Introduction

Reagents are substances used to process emissions and are necessary for a utility to comply with federal regulations enforced by the Environmental Protection Agency (EPA). Emission allowances are necessary to comply with the federal Cross-State Air Pollution Rule (CSAPR).

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[44] Thirty percent of the Windsource PPA is recovered from the Windsource Rider. The remaining 70% was included in the fuel clause and recovered from all customers.

Otter Tail proposed to include test-year reagent cost and emission-allowance amounts in its fuel clause adjustment. After the Department objected to the amount of reagent expenses related to the Company's Coyote generating plant to be included in the fuel clause, the parties agreed to reduce the $1,726,412 amount Otter Tail initially proposed by $170,827.

The Company also proposed to include test year reagent cost and emission allowance amounts in the base fuel cost amount, against which actuals would be measured in the energy adjustment rider (also referred to as fuel clause adjustment). The Commission has previously denied a request by Otter Tail to include reagent costs in the rider.[45]

Otter Tail explained that any over- or under-recovery would be addressed through the annual fuel clause true-up process. The Department recommended that the Commission deny the Company's proposed recovery of reagent costs and emission allowances through the fuel clause adjustment.

B. Positions of the Parties

1. Otter Tail

The Company explained that the consumption of reagents and the quantity of reagents used depends on the dispatch of the generating unit—*i.e.*, when the plant is operating, it is consuming reagents. The variability of amount consumed is beyond the Company's control, and makes reagents appropriate for rider recovery.[46] The Company also stated that similarly, plant emission levels depend on the hours of operation and dispatch levels of each plant, and are also appropriate for recovery through the base fuel amount with over- or under-recovery adjusted for through the fuel clause adjustment rider.

The Company proposed certain modifications to Section 13.01 of its Minnesota Electric Rate Schedule to address recovery of reagents and emissions-allowance expenses through the fuel clause adjustment rider, as well as the proceeds of any emission-allowance sales as a credit.

Otter Tail argued that recovery in the fuel clause rider is appropriate, because the rate case has allowed comprehensive review of Company costs and revenues for prudence and reasonableness that the Commission found not available in Docket No. E-017/M-14-649.[47]

2. The Department

The Department objected to the Company's proposal to true up the costs of reagents and emission allowances through the fuel clause adjustment rider.

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[45] *In the Matter of Otter Tail Power's Request for Approval to Review Its Energy Adjustment Rider to Include Emission Control Costs*, Docket No. E-017/M-14-649, Order Denying Petition to Revise Energy Adjustment Rider and Denying Variance Request (May 27, 2015).

[46] Tommerdahl Direct, at 24.

[47] *See* Order Denying Petition to Revise Energy Adjustment Rider and Denying Variance Request (May 27, 2015).

The Department argued that Minn. Stat. § 216B.16, subd. 7, authorizes, but does not require, the Commission to permit automatic adjustment of charges for specified costs, including the cost of reagents. The Department argued that the Commission has previously considered this exact issue, and denied the Company's request to recover reagent costs and emission allowances through the fuel clause.[48] The Department argued that there has been no material change in circumstances since the Commission issued its decision in that matter.

Further, the Department argued that it would be unreasonable to allow fuel clause recovery in this rate case. The Department asserted that while the Company demonstrated the reasonableness of reagent costs in this rate case, the Company's proposed cost recovery in the fuel clause would not be subject to such a comprehensive review, because the costs will automatically flow though the fuel clause rider and on to ratepayers.

Finally, the Department explained that the Commission has asked the Department and other parties to examine the fuel clause adjustment mechanism and to file a proposal for a more appropriate ratemaking mechanism than the automatic flow-through of cost changes in the fuel clause.[49]

C. Recommendations of the Administrative Law Judge

The ALJ recognized that reagent costs, once placed in the fuel clause adjustment rider, could change between rate cases to the detriment of ratepayers. The ALJ also recognized that if the variable expense experienced—whether due to the dispatch of the generation units or fluctuations in commodity price—is lower than the amount of costs placed in the test year as fixed costs, an over payment could occur.

The ALJ found the Company's proposal to be the lower risk alternative, and recommended that the Commission include test year reagent cost and emission allowance amounts as part of the base fuel cost of the fuel clause adjustment, with any over-or under-recovery addressed through the annual true-up process.

D. Commission Action

The Commission respectfully disagrees with the ALJ's recommendations on this issue. The Commission concurs with the Department, and will deny the Company's request. Accordingly, the Commission will adopt certain revised findings and conclusions as set forth below and in the ordering paragraphs.

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[48] *Id.*

[49] *See In the Matter of the Review of the 2011 – 2012 Annual Automatic Adjustment Reports for All Electric Utilities*, Docket No. E-999/AA-12-757, Order Acting on Electric Utilities' Annual Reports and Requiring Additional Filings (June 2, 2016).

Minn. Stat. § 216B.16, subd. 7, authorizes, but does not require, the Commission to permit the automatic adjustment of charges for specified costs. Importantly, Minn. Stat. § 216B.03 continues to require that all rates, including the fuel clause adjustment, be just and reasonable and that "[a]ny doubt as to reasonableness should be resolved in favor of the consumer."

The Commission has previously considered this issue. In Docket No. E-017/M-14-649, the Commission determined that allowing recovery of all reagent costs through the fuel clause, without the careful review of costs as would occur in a rate case, would not be reasonable, and would likely reduce Otter Tail's incentive for efficiency and cost minimization. Otter Tail has not proved in this rate case that its request to recover all costs of reagents through its fuel clause adjustment rider would be reasonable.

Accordingly, the Commission will not authorize Otter Tail to include test-year reagent cost and emission-allowance amounts in the base fuel cost, or to adjust test-year reagent costs and emission-allowance amounts through the fuel clause.

XII. Resolved Financial Issues and Update Requirements

A. Fuel Clause Rider

Based on the Department's recommendation, the Commission will amend ALJ Finding of Fact 229, as follows:

> Otter Tail's proposal to use the E8760 allocator to allocate both base fuel costs and amounts recovered through the Energy Adjustment Rider is reasonable and shall ~~should~~ be adopted. Further, OTP shall ~~should~~ only begin using the ~~10 class~~ E8760 allocation for the energy adjustment upon implementation of the new CIS in 2018. When the new system is operational, it would make allocations across the ten customer classes as recommended by the Department. Finally, OTP shall ~~should~~ submit a compliance filing at least 120 days ahead of the proposed implementation date of the new rates, consistent with the recommendation of the Department.

Otter Tail did not object to this proposed amendment.

B. Cash Working Capital

Otter Tail and the Department agreed that the Cash Working Capital lag days for Property Taxes should be 296.3; the expense lag days for Labor and Associated Payroll Expense should be changed from 16.0 to 15.11; and expense lag days for Tax Collections Available-Franchise Taxes should be adjusted from 27.6 to 23.8. The Commission will require Otter Tail to update the Cash Working Capital to reflect the Commission-approved expense levels in this rate case. Accordingly, the Commission rejects ALJ Finding of Fact 219.

C. Southwest Power Pool Transmission

In its exceptions, Otter Tail requested that the Commission clarify the ALJ's findings related to this matter. The Commission agrees with this request, and will clarify the ALJ's findings to reflect that:

- The Chamber recognized that SPP transmission-related expense remains fluid;
- Otter Tail and the Chamber agreed that the appropriate base-rate amount of net SPP transmission-related expense in the test year should be $530,000, with the differences accounted for in a tracker to track the amounts over and under on an annual basis.

D. Management Incentive Compensation

The Department and the Company agreed to reduce test-year management incentive compensation costs by $170,079, based on Otter Tail's corrected response to Department Information Request No. 132. The adjustment includes removal of management incentive costs of $30,975 and Board of Directors long-term incentive costs of $139,104. The ALJ did not address this issue in his report.

The Commission agrees with the proposed reduction. The Commission will allow Otter Tail to recover management incentive costs in test-year expenses after removal of the agreed amounts of management incentive costs and Board of Directors long-term incentive costs. This adjustment is embedded in the agreed-upon corporate cost allocation adjustment.

E. Production Tax Credits

The ALJ recommended that the Commission approve the Company's proposal to recover Production Tax Credit (PTC)-related expenses through the Renewable Rider after the PTCs expire. And the ALJ agreed with the Department that there should be a true-up of the PTCs included in base rates and the amounts for the renewable rider when the PTCs begin to expire in late 2017.

The Company, the Department, and the Chamber all also agreed that the Company should increase the PTCs in the 2016 test year and reduce the Company's tax expense by $76,828, and that the Company should true-up and recover the difference between projected PTCs in base rates and actual PTCs in its Renewable Rider prior to the PTCs expiration. The Commission concludes these additional agreements are consistent with the ALJ's findings and recommendation and will so approve them.

F. Charitable Donations

Utilities are allowed to recover 50% of charitable contributions as operating expenses if they qualify under Minn. Stat. § 300.66, subd. 3,[50] and the Commission deems the contributions prudent.

Otter Tail initially proposed to include the following costs in test-year contributions:

- $12,221 paid to Minnesota Utility Investors, Inc. and Minnesota Business Partnership;
- $9,741 for the purchase of circus tickets and grills; and
- $221 for a Chamber Customer Appreciation Day, University of Minnesota picnic, and Faith Haven Camps.

Following an objection by the OAG, the Company agreed to exclude the $12,221 paid to Minnesota Utility Investors, Inc. and Minnesota Business Partnership. The ALJ did not make a finding of fact on the recommended disallowance.

The Commission will allow Otter Tail to recover the costs of the following donations in its test-year expenses:

- $9,741 for the purchase of circus tickets and grills; and
- $221 for a Chamber Customer Appreciation Day, University of Minnesota picnic, and Faith Haven Camps.

G. Employee Expenses – One-Page Summary

Minn. Stat. § 216B.16, subd. 17(b), requires utilities to provide a summary of the total amounts for each expense category included in the utility's proposed test year.

Otter Tail stated that its budgeting system does not provide budgeting information at a level of detail that allows the Company to prepare a one-page summary of total amounts in each expense category for the test year. Instead, Otter Tail provided a one-page summary of 2015 employee expenses.

The OAG argued that Otter Tail's submission did not comply with Minn. Stat. § 216B.16, subd.17(b), but did not request a particular remedy to address the issue.

The Administrative Law Judge agreed with the OAG, and recommended that in Otter Tail's next rate case, the Company should produce a one-page summary of total amounts in each expense category for the 2016 test year.

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[50] Minn. Stat. § 300.66, subd. 3, allows a corporation to contribute to various groups organized and operating for religious, charitable, philanthropic, benevolent, literary, artistic, educational, civic, or patriotic purposes.

In its exceptions, Otter Tail requested that the Commission clarify the ALJ's Finding 658 to indicate that the one-page summary of employee expenses should correspond to the test year proposed for the Company's next rate case, and not the 2016 test year.

The Commission agrees that Otter Tail's filing in this rate case does not comply with the statute, and will require the Company to produce a one-page summary in each expense category, and will amend the Administrative Law Judge's Finding of Fact 658 to read as follows:

> The Administrative Law Judge agrees and finds that OTP did not meet the presentation requirement. In its next rate case, it should produce a one-page summary of total amounts in each expense category ~~for the 2016 Test Year~~.

XIII. Interim-Rate Recovery

A. Introduction

In the Order Setting Interim Rates, the Commission approved the recovery of certain costs, including some previously approved for rider recovery. These costs included remaining unamortized portions of its generation-related Big Stone II development costs, Environmental Cost Recovery Rider costs, Transmission Cost Recovery Rider costs, and Renewable Resource Adjustment Rider costs. The Commission approved the Company's interim-rate request with modifications on April 14, 2016.

B. Recovery of Big Stone II Generation-Related Development Costs

In Otter Tail's last rate case,[51] the Commission authorized the Company to recover Big Stone II generation-related development costs beginning October 1, 2011. In its initial filing in this rate case, Otter Tail proposed to recover the remaining unamortized portion of Big Stone II generation-related development costs in interim rates. Due to over-collection of the unamortized amount of Big Stone II generation-related costs (caused by errors in Otter Tail's calculations based on the assumed implementation date of interim rates), Otter Tail collected more in interim rates from Big Stone II generation-related development costs than appropriate.

Otter Tail agreed to refund any over-collection of Big Stone II generation-related development costs in its interim-rate refund.

C. Positions of the Parties

1. Otter Tail

The Company asserted that the Environmental Cost Recovery Rider, Transmission Cost Recovery Rider, and Renewable Resource Adjustment Rider costs are appropriately being recovered in interim rates, but adjusted their amount for timing and to reflect an appropriate rate

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[51] Docket No. E-017/GR-10-239.

of return. In its direct testimony, Otter Tail explained the following annualized adjustments it had made to interim rates:

- Environmental Cost Recovery Rider - $172,967
- Transmission Cost Recovery Rider - $142,004
- Renewable Resource Adjustment Rider - $45,574[52]

2. The OAG

The OAG disagreed with the proposed adjustments, arguing that allowing recovery of costs before parties can address and contest them creates a presumption that the costs are appropriately recoverable. The OAG also disagreed that the Company was following normal cost-recovery treatment in interim rates. The OAG argued that interim rates were $500,000 too high.

D. The Recommendation of the Administrative Law Judge

The Administrative Law Judge found that the Commission had approved each of the interim-only costs in other dockets, and found them appropriate for inclusion in rates. The ALJ also found that at the conclusion of the rate case, the Commission could order interim-rate refunds to address any concerns. Finally, the ALJ recommended that the Commission decline to disallow the costs requested by the OAG.

E. Commission Action

The Commission finds that Otter Tail's costs under its Environmental Cost Recovery Rider, Transmission Cost Recovery Rider, and Renewable Resource Adjustment Rider adjustments were appropriate to recover in interim rates. These amounts have been subjected to Commission review in other dockets and do not need to be revisited.

But the Commission will order Otter Tail to provide a detailed reconciliation of Big Stone II generation-related development costs that reflects the Commission's final order, including any over-recoveries as part of the interim-rate refund.

XIV. Integrated Transmission Service Agreement – Missouri River Energy Services

A. Introduction

The Western Minnesota Municipal Power Agency (WMMPA) has transmission facilities in a 6,400 square-mile area entirely within Otter Tail's service area. Missouri River Energy Services (MRES),[53] a not-for-profit joint-action agency, uses WMMPA's transmission facilities. MRES's mission is to help municipalities that operate their own electric systems to work together in planning for future power-supply needs.

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[52] In Docket No. E-017/M-12-708, the Commission instructed Otter Tail to address the uncollected balance in its next rate case. The Company collected the balance of $67,361 over 18 months, which resulted in a $45,574 annualized adjustment.

[53] MRES serves members in Iowa, Minnesota, North Dakota, and South Dakota.

Otter Tail, MRES, and WMMPA entered into an integrated transmission agreement (ITA) in 1986, under which Otter Tail operated all transmission facilities within the system. Otter Tail also maintained WMMPA's transmission facilities within the system, and performed certain operation and management services.[54] This agreement expired at the end of 2015.

In 2016 Otter Tail and WMMPA entered into a new Operational and Supplemental Services Agreement, with MRES serving as the agent for WMMPA. Under the new agreement, Otter Tail performed a different, and reduced, range of services for WMMPA/MRES.

The issue in this rate case is what level of test-year Operations and Maintenance (O&M) expense Otter Tail should recover for the 2016 Operational and Supplemental Services Agreement.

B. Positions of the Parties

1. Otter Tail

In contrast to Otter Tail's revenues under the 1986 ITA, which were based on a percentage of total transmission O&M expenses, Otter Tail's revenues under the new Operational and Supplemental Services agreement (Supplemental Services Agreement or 2016 Agreement) are based on a flat annual fee.[55]

Once the 2016 Agreement was implemented, Otter Tail recommended revising the 2016 test-year revenues to use the actual 2016 Supplemental Services Agreement's revenues of $220,000 (Minnesota) in the rate-case revenues. The Department and the OAG supported this proposal.

Otter Tail stated that the 2016 test year also includes all transmission-related revenues from WMMPA/MRES. With the update of the test-year revenues from the 2016 Agreement, Otter Tail proposed to reduce the test-year revenues included in the 2010 rate case by approximately $730,000 on a Minnesota basis.

Level included in 2010 rate case (under 1986 Integrated transmission agreement)	$950,000
Actual revenues	(220,000)
Proposed adjustment to revenues	$730,000

Otter Tail made no adjustment for reduced transmission costs under the 2016 Agreement, stating that because of the type of services provided to MRES/WMMPA, and the manner in which the Company provided such services, it did not anticipate a reduction in transmission costs in the test year.

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[54] Weirs Rebuttal, at 12. Otter Tail based its revenues under the 1986 ITA on a percentage of total transmission O&M expenses.

[55] Weirs Rebuttal, at 12; Weirs Surrebuttal, at 4.

2. The Department and the OAG

The Department and the OAG argued that it is not reasonable for the Company to reduce only revenues in the 2016 test year, and not the related Operations and Management (O&M) transmission costs associated with the reduced revenues. The agencies argued that the Commission should also reduce O&M expenses by approximately $730,000 to account for the smaller scope of the 2016 Agreement, and the fact that Otter Tail will be performing less transmission work (with two fewer employees) on behalf of MRES in the test year.[56]

The agencies disputed the Company's argument that, because of the type of services it provides under the 2016 Agreement, and the manner of billing for those services, there will be no reduction in net expenses. The Department argued that a test-year adjustment is necessary to reflect the fact that Otter Tail will be performing less transmission work on behalf of MRES in the test year due to the expiration of the 1986 ITA and its reduced responsibilities under the 2016 Agreement.[57]

Due to the paucity of actual numbers established in Otter Tail's testimony on this topic, the Department recommended a dollar-for-dollar reduction in the Company's level of O&M expense. Both the Department and the OAG recommended that the Commission require Otter Tail to reduce test year O&M expenses by $730,000.

C. Recommendation of the Administrative Law Judge

The ALJ found that the Company's revenues under both the 1986 ITA and the 2016 Supplemental Services Agreement do not follow directly from the expenses incurred to provide services to MRES and WMMPA.

The ALJ concluded that the 2016 test year appropriately reflects all revenues associated with Otter Tail's O&M service to WMMPA/MRES. The ALJ recommended that the Commission adopt the revenue adjustment included in the Company's rebuttal testimony of $730,000.

D. Commission Action

The Commission respectfully disagrees with certain of the Administrative Law Judge's findings and his recommendation on this issue, as well as with the recommendations of the Department and the OAG.

The Commission finds that Otter Tail has not fully met its burden of proof to establish its requested level of recovery. The record establishes that the Company will have reduced responsibilities on behalf of MRES under the Supplemental Services Agreement. Further, the Company acknowledged that there are now two fewer employees doing that work.[58] Thus, the Commission finds unpersuasive the Company's claim for full recovery.

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[56] Weirs Rebuttal, at 13.

[57] Johnson Direct, at 42–43.

[58] Weirs Rebuttal, at 13–14.

Nor, however, does the Commission find the Department's proposal for a dollar-for-dollar reduction in the recoverable level of expense to be reasonable. Although the record indicates that reduced costs should flow from the Company's reduced responsibilities under the Supplemental Service Agreement, it is unreasonable to assume a dollar-for-dollar reduction since the initial price paid by the Company was not based on a dollar-for-dollar cost calculation. The record reasonably establishes that some significant portion of the initial costs remain.

Accordingly, the Commission finds that a test-year adjustment is necessary to reflect the Company's costs, while recognizing Otter Tail's reduced responsibilities for Missouri River Energy Services under the Supplemental Services Agreement, and with fewer employees, in the test year and beyond. The Commission will therefore disallow $547,000 of the Company's requested recovery. To adjust for the changes, the Commission will allow $182,500, or approximately 25% of the Company's requested expense recovery in this rate case.

Finally, if Otter Tail seeks recovery of MRES expenses in its next rate case, the Commission will require the Company to provide additional detail to clearly delineate and justify such amounts. If Otter Tail does not better establish its requested recovery in the next rate case, the Commission will deny further recovery of these expenses.

XV. Operations and Maintenance Expenses

A. Introduction

Generally, the Commission has examined a utility's Operations and Maintenance expenses in a rate case on an issue-by-issue basis for individual items, and not on a macro level. In this rate case, however, Otter Tail proposed an overall level of O&M expenses in its budget for the 2016 test year. Otter Tail stated that the test-year O&M amounts were based on 2015 O&M amounts, adjusted to reflect known changes for 2016. The OAG disputed the Company's calculation, and recommended that the Commission use historical actuals based on a 2013 – 2015 average, and not a projected budget.

B. Positions of the Parties

1. Otter Tail

To arrive at its 2016 O&M budget, Otter Tail started with its 2015 budget and made adjustments to reflect known changes for 2016.

The Company stated that it had submitted the 2016 O&M budget for review by various business areas within the Company. The Company stated that Otter Tail Power's and Otter Tail Corporation's Boards of Directors have approved the budget. Otter Tail then made a number of adjustments to its 2016 budget to calculate its 2016 test-year O&M expense. Otter Tail explained that it conducted several tests of reasonableness for the 2016 test-year O&M budget.[59]

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[59] The tests compared (1) budgeted O&M expense to actual O&M expense; (2) actual 2014 O&M expense to actual 2015 O&M expense; and (3) budgeted 2016 O&M expense to 2014 and 2015 actual O&M expense.

Otter Tail argued that its actual expenses, by FERC account, have averaged only 0.12% above budget for 2013 – 2015, and 1.68% below budget for the period 2011 – 2015. The Company explained that its 2015 O&M expense was approximately 3.62% below the budgeted expense, due to the commencement of significant projects at the Big Stone and Coyote plants and the reclassification of those O&M expenses as capital costs.[60]

Otter Tail argued that its 2016 O&M budget represents a 3.2% increase over its 2014 actuals, or approximately 1.6% per year. The Company's net rate base grew by approximately 14% over that period, and sales grew almost 17.2%. Based on those calculations, Otter Tail argued that its 2016 O&M budget is a reasonable representation of what will occur in 2016.

Further, Otter Tail argued its 2016 budget is reasonable, given the planned growth in the business going forward, including a projected growth in rate base of some $858 million (Otter Tail total) of capital expenditures over the 2016 – 2020 time frame.

Finally, the Company argued that both Minnesota Power and Xcel Energy use budgets to develop forward-looking test-year O&M expenses, and not historical averages.

2. OAG

The OAG recommended that the Commission set 2016 test-year O&M expense equal to the average historical actual O&M expense during the 2013 – 2015 period. The OAG acknowledged that a reasonable level of test-year O&M expense could be calculated based on budgets, but recommended as a better approach the use of a normalized level of historical, actual O&M expense.

The OAG argued that using a historical average better protects ratepayers than using a projected budget. The OAG disagreed, however, with Otter Tail that the Company's reclassification of the Big Stone and Coyote plants caused the $4.3 million dip in 2015 O&M expenses. The OAG argued that its analysis showed that, as the 2015 expenses were $4.3 million lower than budget, and the Company's 2014 expenses were $4.6 higher than budget, the differences offset each other and support the proposed use of a three-year average.

Based on its analysis, the OAG recommended using the three-year (2013 – 2015) historical average to determine the appropriate 2016 test-year amount, or approximately $1 million over 2015 actual O&M expenses.[61]

C. Recommendation of the Administrative Law Judge

The Administrative Law Judge found that the Company's 2016 O&M budget represents a reasonable 3.2% increase over 2014 actuals, or approximately 1.6% per year.

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[60] The Company originally considered the O&M expenses for the Big Stone and Coyote plants to be routine O&M projects; it later re-categorized the expenses as capital projects based on the scope and type of work performed**.** Otter Tail switched both labor and non-labor costs for these projects from O&M to capital costs.

[61] Lindell Surrebuttal, at 25.

In reaching this result, the ALJ noted that the Company's 2015 O&M expenses were abnormally low due to its re-categorization of Big Stone expenses as capital expenses, and the limited operation of the Coyote plant. The ALJ also found that there have been significant changes to the Company's financials, rate base, and operations since 2013, with both sales and rate base growing over 14%. Importantly, the ALJ found that Otter Tail has projected its rate base to continue to grow after the test year, with some $858 million (Otter Tail total) of capital expenditures planned by 2020.

D. Commission Action

The Commission concurs with the Administrative Law Judge on this issue; it accepts and adopts the ALJ's Findings and Recommendations (Findings 384 – 394).

The Commission appreciates the input of the OAG to highlight and clarify this issue. However, the Commission believes that with a forward-looking test year, the better approach is to use the forward-looking, but substantiated, projected budgets, and not rely on historical averages.

The Commission encourages the Company to continue to plan and make O&M investments to build for the future for the benefit of its ratepayers.

XVI. Investor-Relations Expense

A. Introduction

As a regulated utility, Otter Tail uses capital funding from its investors to accomplish multiple tasks. Otter Tail included $188,314 in the test year for investor-relations expenses, which is 100% of the Minnesota share of investor-relations expenses allocated to Otter Tail by its parent company. The Department seeks to disallow 50% of the expense, or $94,157, from the test year.

The issue is whether to include 100% or 50% of investor-relations expense in the test year.

B. Positions of the Parties

1. Otter Tail

Otter Tail asks the Commission to allow it to recover 100% of the investor-relations expense in the test year. The Company asserted that there is no basis for the Department's proposal to impose a 50% limit on recovery of these expenses, other than that the Commission disallowed that amount in Xcel's last rate case.

Otter Tail challenged the requested 50% disallowance as arbitrary and unreasonable as, in its previous rate cases, the Commission has found investor-relations costs to be a prudent and necessary cost of business to serve Minnesota customers. Further, Otter Tail asserted that the Commission has never specifically articulated a rationale for the 50% disallowance, other than that the parties had agreed that it was appropriate.

Otter Tail also emphasized that the Department's recommendation does not account for the fact that the benefits of the corporate investor-relations expenses are heavily weighted to Otter Tail and its ratepayers.[62] The Company explained that it is in the process of significant capital spending that will largely accrue to the benefit of its ratepayers and argued that it depends on strong relationships with both the debt and equity capital markets to raise the necessary funds.

Otter Tail argued that for 2014 and 2015, as well as 2016 – 2019, virtually all of the equity raised by Otter Tail Corporation is to be invested in the utility to fund capital expenditures made on behalf of ratepayers.[63] Finally, Otter Tail stated that during a period of such substantial infrastructure spending, its investor relations efforts are critical.

2. The Department

The Department argued that 50% ($94,157) of Otter Tail's investor relations expense should be excluded from the test year to provide a reasonable sharing of these expenses between ratepayers and shareholders. The Department stated that many of the functions performed within the Company's investor-relations department are more appropriately shareholder costs.

The Department argued that some of these costs appear principally to benefit shareholders, such as the cost of the annual shareholders' meeting. The Department acknowledged that it is necessary to ensure that Otter Tail shareholders receive reasonable information about the Company, but argued that these costs should be the responsibility of shareholders, and not ratepayers. The Department argued that clearly it is not reasonable to allocate 100% of the costs to ratepayers.

The Department recommended that the Commission disallow 50% of the Company's claimed investor-relations expense. The Department asserted that excluding 50% of investor relations expenses from the test year is reasonable, and is consistent with other recent Commission rate-case decisions on this issue.

C. Recommendations of the Administrative Law Judge

The ALJ focused primarily on the costs to the Company of obtaining the equity capital necessary to achieve the capital structure set by the Commission. Further, the ALJ noted that Otter Tail Corporation has projected that virtually all of the equity raised by it in the near term will be invested in Otter Tail to fund capital expenditures.

The Administrative Law Judge recommended that the Commission permit Otter Tail to recover 100% ($188,314) of the Minnesota share of investor-relations expenses allocated to the Company in the test year. In reaching his recommendation, the ALJ noted recent Commission decisions in which the Commission adopted ALJ recommendations to disallow 50% of investor-relations expenses. The ALJ observed, however, that the Commission did not specifically address the issue in the prior cases.

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[62] Tommerdahl Rebuttal, at 56.

[63] *Id*. at 57–58.

D. Commission Action

The Commission does not accept the ALJ’s recommendation to assign 100% of investor-relations expenses in the test year to ratepayers. Instead, it will allow Otter Tail to recover 50% of its investor-relations expense from ratepayers.

The Commission agrees that it is necessary for the Otter Tail Corporation to provide reasonable information to its shareholders, and that in the next few years Otter Tail Corporation will be investing significant amounts in capital projects that will provide economic benefit to the utility as well as its other subsidiaries. The Commission does not find, however, that it is reasonable to allocate 100% of the costs of investor relations to ratepayers on the record developed in this matter.

The Commission agrees with the Department that a significant portion of the investor-relations costs identified by the Company appear principally to benefit shareholders. The Company has not met its burden to show that 100% of these costs benefit ratepayers. Accordingly, to resolve doubt in favor of ratepayers and reasonably and equitably share such expenses between shareholders and ratepayers, the Commission will disallow half of the proposed test-year investor relations expenses.

XVII. Allowance for Funds Used During Construction and Construction Work in Progress

A. Introduction

Construction Work in Progress (CWIP) and Allowance for Funds Used During Construction (AFUDC) are accounting devices used to permit utilities to recover the cost of capital used during construction. Capital costs incurred during construction are placed in rate base as CWIP. Utilities add the associated financing costs to net operating income as AFUDC, which normally offsets any return on CWIP until the plant under construction goes into service. A utility recovers CWIP and AFUDC over the life of the asset through the recording of book depreciation expense.

The Commission is authorized to consider CWIP and AFUDC in ratemaking under Minn. Stat. § 216B.16, subds. 6 and 6a.

The issue is whether the Company should be permitted to continue placing CWIP in rate base and offsetting AFUDC from the income statement.

B. Positions of the Parties

1. The OAG

The OAG recommended that:

- AFUDC should not apply to any projects where construction is suspended for a period of three months;
- A minimum project-cost threshold of $100,000 should be imposed for AFUDC to accrue;

- The AFUDC rate should be based solely on long-term and short-term interest rates; and
- Otter Tail should remove CWIP from rate base and AFUDC from income because projects under construction are not used and useful for the benefit of ratepayers.

2. Otter Tail

The Company explained that it uses a combination of debt and equity and earnings to finance CWIP. Otter Tail argued that it follows Commission standards in its treatment of CWIP and AFUDC.[64]

Otter Tail argued that prohibiting AFUDC on a project that is inactive for three or more months would represent a new limitation of AFUDC. The Company noted that stopping construction during the winter months in Minnesota (approximately November through March) would lead to suspension of AFUDC.

Otter Tail argued that the OAG made essentially the same arguments about CWIP and AFUDC in each of the last two Xcel electric rate cases, and that in each case the Commission rejected OAG's arguments.[65] In Xcel's 2013 rate case, the Commission found no reason to change Xcel's practice of accruing AFUDC on projects larger than $25,000. According to Otter Tail, the OAG has presented no additional rationale that should persuade the Commission to limit the accrual of AFUDC to projects over $100,000 in this rate case.

In Xcel's 2013 rate case, the Commission also rejected the OAG's claim that excess revenues should be used to finance capital projects and that the AFUDC rate should be based solely on long-term and short-term interest rates. Again, the Company argued that the OAG presented no reason why the Commission should, in this rate case, impose such limitations. Otter Tail argued that, like Xcel, its rates are based on cost and do not include an extra component for financing of construction activities.

Otter Tail argued that its cash from operations represents a combination of the "return of" investment to investors and "return on" investments (earnings on common stock previously invested).[66] Both of these sources of cash are owned by investors and cannot be used to finance CWIP without compensation to investors.

C. Recommendation of the Administrative Law Judge

The Administrative Law Judge found that it is not appropriate to conscript the resources of Otter Tail's shareholders for financing utility projects without compensating the owners of those resources.[67] The ALJ also found that prohibiting the accrual of AFUDC on a project that is inactive for three months would represent a new limitation on AFUDC, and could end accruals

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[64] *See* Minn. Stat. § 216B.16, subds. 6 and 6a; Beithon Direct, at 36–39.

[65] *See* Docket Nos. E-002/GR-12-961, E-002/GR-13-868.

[66] Beithon Rebuttal, at 38–39.

[67] ALJ's Report ¶ 399.

on active projects that are interrupted during cold winter conditions between November and March.

The ALJ recommended that the Commission decline to adopt the OAG's rationale on CWIP and AFUDC.

D. Commission Action

The Commission concurs with the Administrative Law Judge's findings (398 – 401), and will decline to adopt the OAG's proposed limitations on CWIP and AFUDC. The Commission previously has considered virtually the same objections raised by the OAG in the last two Xcel rate cases. The OAG has not introduced any new or additional facts or law that would lead the Commission to a different conclusion in this rate case.

XVIII. Employee Expense – Flex Field

A. Introduction

Minn. Stat. § 216B.16, subd. 17, requires utilities to include in a general rate case petition schedules that separately itemize travel, entertainment, and related employee expenses as specified by the Commission. In addition, in Otter Tail's last rate case, the Commission required that the Company, in its next rate case, to:

> . . . file the information required by Minn. Stat. § 216B.16, subd. 17, in a searchable, sortable format. The Company shall modify the information describing the business purpose for each expense to more clearly describe the purpose. The filing shall include the name of the employee incurring the expense and the jurisdictional share of the expense. The filing shall also include a reference document that clearly describes what type of costs and activities are included in each business purpose category used by the Company.[68]

The Company worked with the Department, the OAG, and Commission staff concerning the types of employee-expense data that the Company would file in its next rate case. On July 24, 2013, Otter Tail made an informational filing explaining how it would report employee-expense data in its next rate case, including its rationale and use of monetary thresholds.

B. Positions of the Parties

1. Otter Tail

In its filing, Otter Tail included itemized employee-expense schedules as required by Minn. Stat. § 216B.16, subd. 17, including an itemization of 2015 employee expenses for travel, meals, and lodging of $542,741 (Otter Tail MN).

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[68] *In re Otter Tail Power Company's Petition for Authority to Increase Rates for Electric Utility Service in Minnesota*, Docket No. E-017/GR-10-239, Findings of Fact, Conclusions, and Order, at Ordering Paragraph 12 (April 25, 2011).

Otter Tail stated that its employee-expense reporting system conforms to the procedures set out in its July 2013 filing. The Company explained that its reporting system does not require narrative descriptions in the flex field for transactions under certain monetary thresholds: $175 for lodging, $35 for meals, and $475 for travel.[69] Otter Tail argued that a narrative description in the flex field itself is unnecessary to a determination of reasonableness, because the Company provided other information that, taken together, demonstrated the reasonableness and purpose of the expense.[70]

Otter Tail explained that to provide additional narratives in the flex field for every transaction, the Company would need to hire at least one additional full-time employee for data entry. The Company would also incur additional costs associated with the time and effort of employees providing the narrative description to Company data-entry personnel.[71]

The Company argued that the Commission should reject the OAG recommendations, as the agency requested a level of business purpose detail that is not required by statute or order and such information is not necessary to determine the business purpose of the transaction. The Company asserted that its proposed approach, set out in its July 2013 filing, balances the OAG's desire for additional business purpose information and the cost to the Company and its ratepayers of collecting and maintaining that information.

2. The OAG

The OAG recommended that the Commission disallow $97,982 in employee travel, meal, and lodging expenses because the information submitted by the Company was inadequate to determine whether the expenses were reasonable or necessary for the provision of utility service. OAG argued that 3,568 transactions relating to these expenses lacked sufficient information to determine whether they were reasonable or necessary.

Specifically, the OAG argued that the challenged expenses lack a narrative explanation with data on the meeting topics, description of fieldwork or business purpose, name of the employee for whom the expense incurred, and detail of the expense on the expense schedule form, as required in the Company's last rate case.

The OAG asserted that the expense filing failed to comply with Minn. Stat. § 216B.16, subd. 17, in that it did not provide sufficient business-purpose detail for the bulk of the transactions listed. The OAG also argued that the Company did not uniformly follow its internal threshold amounts (limiting when a business purpose is required).

Finally, the OAG asked the Commission to order the Company to use the available flex fields in its accounting system to record the business purpose and other transaction information for all transactions, regardless of amount involved.

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[69] Tommerdahl Direct, at 69–71.

[70] Tommerdahl Rebuttal, at 39–40.

[71] Tommerdahl Rebuttal, at 41.

C. Recommendation of the Administrative Law Judge

The ALJ found that the Company's use of thresholds to provide additional business-purpose data was reasonable. The ALJ also found that Otter Tail had provided sufficient business-purpose information for transactions under the thresholds to determine whether the expenses were reasonable and necessary for the provision of utility services.

The Administrative Law Judge recommended that the Commission approve the Company's $97,982 in employee travel, meal, and lodging expenses for the 2016 test year.

D. Commission Action

The Commission concurs with the Administrative Law Judge's findings, conclusions, and recommendation on rate recovery of these expenses. The Company has provided adequate detail in the course of this proceeding to demonstrate that the expenses claimed are reasonable and necessary for the provision of utility service.

Further, the Commission finds that Otter Tail's use of thresholds to provide additional business-purpose information is reasonable. Otter Tail has demonstrated that it has met the statutory criteria in Minn. Stat. § 216B.16, subd. 17.

Finally, Otter Tail has provided sufficient business-purpose information for transactions under the thresholds to determine whether the expenses are reasonable and necessary for the provision of utility service. The Commission will approve Otter Tail's $97,982 in employee travel, meal, and lodging expenses for the 2016 test year.

XIX. Employee Expense – Gifts

A. Positions of the Parties

1. Otter Tail

Otter Tail included in its test-year expenses a total of $18,310 (Otter Tail MN) for gift expenses[72] and $7,380 for employee recognition and employee entertainment expenses.[73] Otter Tail asserted that the expenses recognize employee achievement, acknowledge life events such as retirements and deaths, and mark holidays and other special events.

The Company argued that it categorized nearly all the items listed in its gift schedule under activity code 1080 – Employee Recognition Programs. The Company argued that the description of these activities along with the information provided in the Company's gift schedules demonstrates that the gifts are extremely modest, reasonable and prudent, and should be eligible for rate recovery as they help to build employee morale and promote retention.

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[72] These expenses include $7,742 for employee recognition, $4,563 for holiday gifts, $3,310 for employee life events (such as retirements and funerals), and $298 for prizes at safety meetings. Otter Tail Initial Filing, Schedule 06-2015 Gift Expenses.

[73] Tommerdahl Rebuttal, at 44.

2. The OAG

The OAG objected to asking ratepayers to pay for these expenses, arguing that ratepayers already pay all employee compensation costs necessary for the provision of utility service. The OAG urged the Commission to disallow the requested $18,310 as well as the $7,380 in employee recognition and entertainment expenses.

The OAG argued that the Commission has not allowed such expenses in the Company's prior rate cases, and in Otter Tail's 2010 rate case specifically disallowed employee gifts as unreasonable and unnecessary for the provision of utility service. The OAG requested that the Commission again disallow all such costs.

B. Recommendations of the Administrative Law Judge

The Administrative Law Judge recommended disallowing the Company's request for rate recovery of $18,310 for gifts, life events, and other employee gift expenses and $7,380 in employee recognition and entertainment expenses. The ALJ reasoned that, in the Company's last rate case, the Commission had disallowed inclusion of these types of expenses in the test year. Therefore, absent a willingness by the Commission to revisit its earlier holding, the $18,310 for gifts, life events, and other employee gift expenses, and the $7,380 in employee recognition and entertainment expenses should be excluded from test-year expenses.

C. Commission Action

The Commission concurs with the Administrative Law Judge and will disallow rate recovery of the Company's proposed employee gift and recognition expenses.

The Administrative Law Judge recommended disallowing the $18,310 for gifts, life events, and other employee gift expenses, and $7,380 in employee recognition and entertainment expenses. The ALJ reasoned that the hearing record in this matter, and the legal arguments for approving the proposed expenses, are akin to those in the Company's last rate case, in which the Commission denied recovery. Therefore, absent a willingness by the Commission to revisit its decision in the 2010 rate case, Otter Tail's proposed employee recognition and employee gift expenses should be denied.

The Commission finds that the evidence adduced and the arguments presented in this rate case are similar to those of the last rate case. The Commission finds that the proposed employee gift and recognition expenses are not reasonable and necessary for the provision of utility services. The Commission will deny recovery for these items.

XX. Lobbying and Organizational Dues

A. Introduction

OTP seeks full recovery of organizational dues expenses. The OAG disagreed with the Company's request. The OAG recommended that the Commission deny $89,573 of Minnesota-jurisdictional dues paid to the Edison Electric Institute and the Lignite Energy Council because the organizations are primarily lobbying organizations that advocate on behalf of investor-owned utilities and do not benefit ratepayers.

B. Positions of the Parties

1. The OAG

The OAG challenged rate recovery of dues paid to the Edison Electric Institute and the Lignite Energy Council, arguing that they are primarily lobbying groups. The OAG argued that Otter Tail has not provided record support for the portion of the dues allocated to lobbying expenses, nor has it shown that membership in these organizations benefits ratepayers.

2. Otter Tail

Otter Tail agreed that it should not recover lobbying expenses. The Company explained that it has reduced the dues payable to both organizations to exclude the portion of the charges for lobbying activities.

Otter Tail claimed that in addition to lobbying activities, these organizations provide valuable services, information, and expertise the Company cannot duplicate on its own. Otter Tail explained that the Edison Electric Institute provides public-policy leadership, critical industry data, market opportunities, strategic business intelligence, conferences, products, and services. Otter Tail also asserted that in the Company's 2010 rate case, the Commission allowed recovery of dues paid to these organizations.

At oral argument, Otter Tail agreed to withdraw its request for the organizational dues for the Lignite Energy Council.

C. Recommendation of the Administrative Law Judge

The ALJ found that both organizations provide valuable services and information that benefit ratepayers, which the Company cannot duplicate cost-effectively on its own.

He also found that the Company had established that the 2016 test year dues for these organizations do not include non-recoverable lobbying expenses. The Company itemized its lobbying expenses for these organizations in FERC Account 426.4, a below-the-line account.

Finally, the ALJ noted that the OAG's arguments against recovery of membership dues in these organizations were the same as those it advanced in Otter Tail's last rate case, which the Commission rejected. Accordingly, the ALJ recommended that the Commission approve recovery of the organizational dues in its 2016 test year.

D. Commission Action

The Commission concurs with the Administrative Law Judge's findings, conclusions, and recommendations on rate recovery of expenses for the Edison Electric Institute. The Company has provided adequate detail demonstrating that the expenses claimed are reasonable and necessary for the provision of utility service.

The Commission will modify the ALJ's Finding of Fact 444 to exclude the recovery of Lignite Energy Council dues from the test year, as the Company has withdrawn that portion of its request.

Further, in future rate cases the Commission will require that if the Company seeks recovery of organizational dues of this nature, it must support its claim by providing information that identifies on membership invoices the amount of dues paid and the portion of dues charged for lobbying activities.

COST OF CAPITAL ISSUES

Utilities meet their capital needs by issuing stock, known as equity, and by incurring long-term and short-term debt; these three components make up the utility's capital structure. Generally, equity is the most expensive form of financing, followed by long-term debt and then short-term debt. The percentage of the capital structure made up of each of these components therefore has a substantial impact on costs and rates, as does the cost determined for each component during the ratemaking process.

In this case, the only contested cost-of-capital issue is the cost of equity. The Company and the Department took the same position on capital structure and the costs of long- and short-term debt—the OAG took none—and all three parties took different positions on the cost of equity.

The Commission will summarize the capital structure and address the cost of equity below.

XXI. Capital Structure

To determine the Company's cost of capital, it is necessary to determine reasonable ratios of long- and short-term debt and common-stock equity, because the costs of each source of financing are different.

Otter Tail Power is a wholly owned subsidiary of Otter Tail Corporation. The Company has separately issued short term debt and long-term debt, and has a separate credit rating, from Otter Tail Corporation. The Company argued, and the Department agreed, that the Company's proposed capital structure is a predominantly market-based capital structure that is reflective of Otter Tail's actual capital structure.

The Company proposed a capital structure that did not differ significantly from the capital structures of comparable utilities or the Company's capital structure approved in its last rate case. The Department concluded that Otter Tail's proposed capital structure is reasonable because it is consistent with those found in comparable utilities. The ALJ also concluded that the Company's proposed capital structure is reasonable. The Commission agrees. The updated 2016 capital structure is set forth below:

Long-Term Debt	44.06%
Short-Term Debt	3.44%
Common Equity	52.50%

XXII. Cost of Equity

A. Introduction

In determining just and reasonable rates, the Commission is required to

> give due consideration to the public need for adequate, efficient, and reasonable service and to the need of the public utility for revenue sufficient to enable it to meet the cost of furnishing service, including adequate provision for depreciation of its utility property used and useful in rendering service to the public, *and to earn a fair and reasonable return upon the investment in such property.*[74]

One of the critical components of that fair and reasonable return upon investment is the return on common equity, which—together with debt—finances utility infrastructure. The Commission must set rates at a level that permits stockholders an opportunity to earn a fair and reasonable return on their investment and permits the utility to continue to attract investment.

In short, the Commission must determine a reasonable cost of equity and factor that cost into rates. Otter Tail is a subsidiary of Otter Tail Corporation, Inc., and has no publicly traded common stock. Its cost of common equity—essential to determining overall rate of return and the final revenue requirement—must therefore be inferred from market data for companies that present similar investment risks. Using a proxy group also moderates the effects of one-time events on a given company's stock.

B. The Analytical Tools

Otter Tail, the Department, and the OAG conducted cost-of-equity studies and based their analysis on comparison groups of utilities they considered similar enough to Otter Tail to serve as proxies in determining the Company's cost of equity. All three used the Discounted Cash Flow (DCF) analytical model, on which this Commission has historically placed its heaviest reliance.

The Company, the OAG, and the Department also used the Capital Asset Pricing Model (CAPM) as a secondary, corroborating resource, consistent with the Commission's historical treatment of this model. The Company also conducted a third analysis using the Bond Yield Plus Risk Premium Model, which the Commission has historically relied on less heavily, considering the model prone to producing volatile and unreliable outcomes.

The DCF model uses the current dividend yield and the expected growth rate of dividends to determine what rate of return is sufficient to induce investment. The model is derived from a formula used by investors to assess the attractiveness of investment opportunities using three

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[74] Minn. Stat. § 216B.16, subd. 6 (emphasis added).

inputs—dividends, stock prices, and growth rates. DCF modeling can be performed using constant, "two-growth,"[75] and multistage dividend growth assumptions.

The CAPM model estimates the required return on an investment by determining the rate of return on a risk-free, interest-bearing investment; adding a risk premium determined by subtracting the risk-free rate of return from the total return on all market equities; and multiplying the remainder by beta, a measure of the investment's volatility compared with the volatility of the market as a whole.

The Bond Yield Plus Risk Premium (or Risk Premium) Model determines the cost of equity by adding to the risk free rate a premium reflecting the greater returns required by equity holders.

C. The Positions of the Parties

1. The Company

The Company proposed a return on equity of 10.05%, based on constant growth, two-growth, and multistage DCF models of an eight-utility proxy group, along with CAPM and Bond Yield Plus Risk Premium analyses.

The Company's chosen proxy group screened out companies using a cap on customers-per-square-mile, and a floor on the comparable companies' return on equity.

The Company also conducted a multistage DCF study, developing inputs for multiple time periods and extrapolating future financial performance from the results. The Company conducted a CAPM study, using 30-year treasury notes as the risk-free asset the study requires. It conducted an risk premium study, also using 30-year treasury notes as the baseline asset.

The Company also advocated for factoring in and adjusting for business risks and other factors specific to the Company's small size, equity-price volatility, and low institutional ownership, trading volume, and performance. According to the Company all of these factors taken together distinguish Otter Tail and justify a high ROE relative to the companies in the proxy group. Finally, the Company's ultimate recommendation of a 10.05% return on equity included an adjustment for flotation costs—the costs of issuing securities—since those costs result in a utility receiving less than the full sales price for shares issued.

2. The Department

The Department proposed a return on equity of 8.66%, the result of applying both a constant- and two-growth DCF model to a proxy group not screened using an ROE floor, using the most recent growth-rate projections for each company in that group, and adjusting the final number to include flotation costs.

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[75] A two-growth model assumes that dividends grow at one rate for a short time, and then grow at a second, sustainable rate in perpetuity.

The Department noted that it had also conducted two CAPM analyses on the companies as a reasonableness check—one using the classic CAPM model and the other the Empirical CAPM model. The agency stated that these studies confirmed the general accuracy of its DCF results, though the CAPM results were lower than those supported by DCF analysis.

The Department rejected the arguments that the cost of equity should be adjusted to reflect the individual factors proposed by the Company, arguing that the proposed adjustments would effectively be double-counting individual risk factors, which are already incorporated into the DCF analysis of the proxy group. And, the Department argued, the Company appeared only to have considered adjusting for individualized factors that appear to make the Company riskier. The Department also opposed granting an upward ROE shift to reward the company for good performance, arguing that the inclusion is not consistent with cost-of-service regulation.

3. The OAG

The OAG proposed a return on equity of 7.14%, based on a multistage DCF study using a different proxy group that did not apply screens used by the Company that the OAG considered unreasonable. The Office also opposed adjusting the DCF results upward to include a flotation adjustment.

The OAG also urged the Commission to base its decision on the DCF analytical model. The OAG pointed to the Commission's heavy historical reliance on the DCF model and to the Department's characterization of the model as "a fair, market-oriented method that uses current, relevant information.

The OAG challenged the Company's execution of the DCF analytical models, arguing that the Company's proxy group unreasonably screened out relevant comparable companies, and that the Company's DCF modeling used outdated market information and imprecise growth rates.

The OAG opposed the Company's and Department's support of a flotation adjustment. The Office argued that the adjustment wasn't needed to access capital markets, and so would be a windfall to the Company.

The OAG also opposed the Company's proposed upward adjustments for factors such as company size, customer concentration, and customer satisfaction for the same reasons the Department opposed them—it argued that adjusting a DCF-based ROE for these factors would effectively account for them twice.

D. The Recommendation of the Administrative Law Judge

The ALJ determined that, consistent with previous Commission decisions, DCF modeling provides the best resource for determining a reasonable cost of equity, and is superior to both CAPM and Bond Yield Plus Risk Premium models for the purpose.

The ALJ recommended that the Commission determine that “familiar, recognized discounted cash flow analyses will be used by the Commission as a starting point for ROE deliberations, and that within the appropriate range of DCF results, the Commission will address company-specific circumstances.” He concluded that the Department’s DCF modeling was superior to the models submitted by the OAG and the Company.

However, the ALJ supported adjusting DCF analysis results “to account for company-specific details.” He recommended that the Commission approve a return on equity on the high end of the Department’s two-growth DCF analysis: 9.54%, which incorporated an upward adjustment for flotation costs.

E. Commission Action

Setting the cost of equity is a fact-intensive and record-specific judgment. The Commission must ultimately establish a reasonable rate of return that is supported by the evidence in the record considered in its entirety.[76] The Commission believes that the record evidence in this case, including the broad diversity of modeling and expert testimony, establishes a range of reasonable costs of equity, within which the Commission must identify one value.

The Commission agrees with the ALJ that DCF analysis provides the best evidence in the record for establishing the Company’s cost of equity in this case. DCF modeling continues to offer analytically rigorous substantial evidence to support a determination of the Company’s cost of equity, with the reasonableness of the results checked by CAPM and Risk Premium analyses. The Commission also agrees with both the Company and Department that the two-growth DCF method is the best approach for determining Otter Tail’s ROE in this instance

A properly constituted proxy group ensures that a DCF analysis is grounded in relevant comparable data. In this case the proxy group used by the Department, prior to eliminating the 7% screen, likely reflects the most appropriate range of reasonably comparable companies for the DCF modeling. The Commission agrees with the Department and the OAG that the proxy-group screens applied by the Company erroneously excluded comparable companies.

On a different record, it may be reasonable to eliminate the 7% screen, as proposed by the Department in surrebuttal testimony; however, in this case the proposal was raised late in the proceeding, with too little opportunity for parties to fully address the issue. And Otter Tail reasonably questioned the Department’s rationale to abandon the screen in this particular case, in light of the overall distribution of ROEs in the proxy group.

Accordingly, the Commission concludes that the most persuasive and well-supported analysis is the Department witness’s surrebuttal testimony and two-growth DCF analysis, with the results adjusted after re-applying the 7% screen. This results in the following ROE range:

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[76] *In Re:App. of Minn. Power for Auth. to Increase Rates for Elec. Serv. in Minn.*, 838 N.W.2d 747, 760 (2013) (describing the substantial evidence test, and citing *Reserve Min. Co. v. Herbst*, 171 N.W. 2d 712, 825 (1977)).

	Mean Low	Mean Average	Mean High
Two-Growth DCF	8.13%	8.98%	9.85%

Using the DCF and other analyses in the record as both a foundation and a guide, the Commission has considered and weighed all the relevant factors. In light of these factors, the Commission will approve, for the reasons stated below, a cost of equity of 9.41%. A 9.41% return on equity is equal to the average of the proxy group's mean ROEs in the Department's two-growth DCF average- and high-growth scenarios, identified as the Midpoint in the following table:

	Mean Low	Mean Average	**Midpoint**	Mean High
Two-Growth DCF	8.13%	8.98%	**9.41%**	9.85%

The record does not formulaically dictate a particular ROE to be approved. Instead, the record presents a range of reasonable returns on equity that the Commission has carefully evaluated based on the analyses and arguments in the record. As such, the Commission is setting the Company's authorized ROE in light of the record as a whole.

The record in this case establishes a compelling basis for selecting an ROE above the mean average within the DCF range, given Otter Tail's unique characteristics and circumstances relative to other utilities in the proxy group. These factors include the company's relatively smaller size, geographically diffuse customer base, and the scope of the Company's planned infrastructure investments. The Commission has also considered Otter Tail's recognized the Company's performance in completing major infrastructure projects substantially under budget,[77] its history of providing reliable service with stable rates, and its record of effectively serving the needs of its customers, as measured by multiple customer-satisfaction metrics.[78]

Although the Department included an Otter Tail ROE in its DCF analyses to adjust for the Company's higher-than-average risk, the Commission concludes that, in this case, including Otter Tail in the proxy group does not adequately account for Otter Tail's unique characteristics; Otter Tail's ROE is only one of 15 ROE values in the calculation.

The Commission recognizes that the ALJ's recommended ROE of 9.54% is also likely within the range of reasonableness established by the record; however, the Commission concludes that a slightly lower ROE is more appropriate. Otter Tail's higher investment-risk profile relative to other utilities in the DCF proxy group—which the ALJ also concluded justified an ROE at the high end of the DCF analysis—is already partially reflected by inclusion of an Otter Tail ROE in the proxy group. To adjust for this, the Commission will approve an ROE below the ALJ's recommendation, but still higher than the mean–average DCF analysis results.

The Commission has determined that the midpoint of the mean–average and the mean–high results appropriately reflects the company-specific adjustments that are appropriate in this case,

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[77] For example, Otter Tail completed its Big Stone Air Quality Control System project approximately 25% below budget and completed its Hoot Lake Mercury Air Toxins Standard project below budget.

[78] For example, Otter Tail tied for the highest ranking in customer satisfaction among midsize utilities in the Midwest in J.D. Power's 2015 Electric Utility Residential Customer Satisfaction Study.

and best balances the interests of ratepayers and the Company. The outcome is that Otter Tail's approved ROE falls midway between the average and higher end of comparable company ROEs. As such, it adequately assures a fair and reasonable return in light of the Company's unique risk profile, substantial capital investment activity, costs of obtaining equity investment, and performance.

To further develop the record on the costs of obtaining equity investment in the Company's next rate case, the Commission will require the Company to provide detailed information on all the costs necessary to obtain equity in its proposed test year, and its plans for acquiring equity through the capital markets for the five years following the test year. With this information, the Commission and the parties can more fully analyze the need for and, if appropriate, amount of any adjustment for flotation costs.

XXIII. Cost of Long-Term and Short-Term Debt

The Company proposed a long-term debt cost of 5.62%. The Department concurred in the 5.62% figure, and the OAG did not address the issue.

The Company initially proposed a short-term debt cost of 3.28%, which it updated to 2.55% in the course of evidentiary proceedings. The Department concurred in the 2.55% figure, and the OAG did not address the issue.

No one challenged the reasonableness of either of these agreed-upon numbers, and the Administrative Law Judge recommended adopting both. The Commission concurs and will set the cost of long-term debt at 5.62% and the cost of short-term debt at 2.55%.

XXIV. Final Capital Structure and Overall Cost of Capital

The final capital structure and overall cost of capital resulting from the decisions made in this order are set forth below:

Component	Ratio	Cost	Weighted Cost
Long-Term Debt	44.0601%	5.6229%	2.4775%
Short-Term Debt	3.4399%	2.5549%	0.0879%
Common Equity	52.5000%	9.4100%	4.9403%
Total	100.000%		7.5056%

CLASS COST OF SERVICE STUDY ISSUES

XXV. Rate Design and Cost of Service

The preceding discussion has sought to quantify the costs that a prudently managed utility serving Otter Tail's service area would bear. The following sections will address how Otter Tail may recover those costs from its ratepayers and earn a reasonable return on its investment. This process of *rate design* requires the Commission to exercise policy judgment because there are many ways to set rates to enable a utility to recover appropriate revenues.

In designing rates, the Commission considers a variety of factors, including:

- Equity, justice, and reasonableness, and avoidance of discrimination, unreasonable preference, and unreasonable prejudice;[79]
- Continuity with prior rates to avoid rate shock;
- Revenue stability;
- Economic efficiency;
- Encouragement of energy conservation;[80]
- Customers' ability to pay;[81]
- Ease of understanding and administration; and, in particular,
- Cost of service.

Estimating the cost to serve any given customer is challenging because a utility will incur different costs to serve different customers, and will incur many costs that benefit multiple customers. Because similar types of customers tend to impose similar types of costs on the system, utilities simplify their analysis by first dividing customers into classes—for example, distinguishing residential customers from commercial or industrial customers. Utilities then attempt to determine the amount of revenues they should recover from each customer class.

To aid this analysis, the Commission directs utilities to conduct a Class-Cost-of-Service Study (CCOSS). Minn. R. 7825.4300(C) directs a utility to file

> A cost-of-service study by customer class of service, by geographic area, or other categorization as deemed appropriate for the change in rates requested, showing revenues, costs, and profitability for each class of service, geographic area, or other appropriate category, identifying the procedures and underlying rationale for cost and revenue allocations.

Otter Tail identified ten customer classes:

- Residential, subdivided into two categories: standard Residential, and Residential—Controlled Demand (RCD).
- Farm
- General Service
- Large General Service
- Irrigation
- Outdoor Lighting
- Other Public Authority Service

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[79] Minn. Stat. §§ 216B.01, .03.

[80] Minn. Stat. §§ 216B.03, .2401, 216C.05.

[81] Minn. Stat. § 216B.16, subd. 15.

- Water Heating.
- Controlled Service – Interruptible
- Deferred Load Service

XXVI. Class Cost of Service Studies

A. Introduction

1. Functionalization, classification, and allocation of costs

According to the *Electric Utility Cost Allocation Manual* of the National Association of Regulatory Utility Commissioners (Electric Manual), performing a CCOSS involves three steps. First, costs are grouped according to their function (generation/production, transmission, distribution, customer service/facilities, administrative). Second, costs are classified based on how they are incurred. Third, costs are allocated to the various customer classes.[82]

Functionalization: In this case, the function that has generated the most dispute is distribution. The distribution system carries electricity from the transmission system to a customer's location. Utilities distinguish between the primary distribution system and the secondary distribution system. In the primary distribution system, electricity travels from the high-voltage transmission system to substations, which reduce the voltage and distribute it via lines and poles to the neighborhoods of retail customers. While some large industrial customers purchase power at primary distribution voltages, generally this electricity flows to the secondary distribution system, where distribution transformers again reduce the voltage, permitting it to be distributed via lines and poles to customer premises.

Classification: The cost of a function might be classified as related to *energy, demand,* or *customers*. Energy-related costs increase as a customer's consumption of energy increases. Demand-related costs increase as the rate at which the customer consumes energy increases, especially during periods of peak demand. Customer-related costs increase as the number of customer accounts increases. According to the Electric Manual, the cost of an electric utility's distribution system is related to energy, demand, and customers.

Allocation: The various costs then get allocated to each customer class. The manner in which these costs get allocated have important rate consequences. For example, because the great majority of Otter Tail's customers are residential customers, a choice to characterize a cost as a customer cost will result in residential customers bearing the great majority of those costs.

According to the Electric Manual, the cost of an electric utility's distribution system is related to energy, demand, and customers.[83] Yet the two methods that the Manual identifies for allocating such costs—the Zero Intercept method and the Minimum System method, discussed below—classify the cost of distribution plant as related to demand and customers, and do not classify any part of the distribution system as related to energy.

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[82] Electric Utility Cost Allocation Manual, National Association of Regulatory Utility Commissioners, at 18–23 (January, 1992).

[83] *Id*. at 21–22.

B. Positions of the Parties

1. The Company

Otter Tail advocated use of the Minimum System method (also called the Minimum Size method). The Minimum System method reflects the premise that a utility builds out its distribution plant to serve each customer regardless of the amount of demand that each customer puts on the system, thus *some* portion of the plant should be regarded as customer-related. To use this method, an analyst estimates the minimum cost to build a system that would connect to all of Otter Tail's customers. The extent to which Otter Tail built a system that was larger than necessary simply to connect to each customer, this excess is attributed to demand—that is, to Otter Tail's need to provide the capacity to serve peak load.

In support of its CCOSS, Otter Tail noted that the Minimum System method is one of the allocation methods recommended in the Electric Manual, and has been previously adopted by various regulators—including this Commission.

Responding to concerns raised by other parties, however, Otter Tail agreed on the need to modify its CCOSS to treat the cost of Conservation Improvement Programs (CIP) as energy-related, rather than customer-related.

2. The OAG

a. The Basic System Method and the Peak and Average Method

The OAG recommended that the Commission rely on Otter Tail's CCOSS based on the Minimum System method—but also rely on CCOSSs based on the Basic System (sometimes called Basic Customer) method and the Peak and Average method. In support of its position, the OAG cited a prior Commission decision directing a utility to consider multiple CCOSS models prospectively.[84]

Similar to the Minimum System method, the Basic System method begins by attempting to identify the subpart of distribution costs that should be attributed to customer-related costs, and presumes that any excess cost should be attributed to demand. But while the Minimum System method relies on estimating the cost of a hypothetical minimum distribution system, the Basic System method identifies costs that can be attributed to individual customers—such as the costs of service lines, meters, billing, and collection—as the basis for estimating customer costs.

In support of the Basic System method, the OAG cited various academic studies and decisions from other jurisdictions.

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[84] *In the Matter of the Application of CenterPoint Energy Corp. for Authority to Increase Natural Gas Rates in Minnesota*, Docket No. G-008/GR-15-424, Findings of Fact, Conclusions, and Order, at 53 (June 3, 2016).

The *Peak and Average* method differs from both the Minimum System and the Basic System methods. These latter methods allocate capacity cost among customer classes based on each class's share of total energy consumption during the utility's peak demand (coincident peak demand). These methods reflect the idea that a utility designs and builds its system to have sufficient capacity to meet the needs of all its firm customers during periods of peak demand, no matter how brief that period is. In practice, this dynamic causes residential consumers to bear a larger share of these costs relative to the amount of energy consumed than do industrial customers.

In contrast, the Peak and Average method characterizes all distribution system costs as capacity costs, but rejects the premise that these costs should be allocated purely on the basis of coincident peak demand. Instead, the Peak and Average method allocates some costs based on each class's average level of usage, reflected by each class's energy consumption or average demand. And it allocates the rest based on peak demand—but the peak demand of *each customer class*, regardless of when that peak occurs (non-coincident peak demand). This has the effect of assigning less distribution-system cost to residential customers, and more to industrial customers.

b. Opposition to Minimum System Method

The OAG criticized Otter Tail's choice to rely solely on the Minimum System method. Because this analytical method relies on comparing Otter Tail's actual distribution plant costs to the cost of a hypothetical minimalist distribution plant, the model depends on the subjective perspectives of the analyst modeling the hypothetical plant. The OAG alleged that this practice tends to over-allocate costs to the customer component. This method contrasts with the Basic System model, the OAG argued, which relies on actual data from the utilities' accounts.

The OAG also criticized Otter Tail's choice to apply the Minimum System model uniformly to the primary and secondary distribution system. The OAG argued that the rationale for allocating the cost of the primary distribution system based on the number of customer accounts is weaker than the choice to allocate the secondary distribution system on this basis.

c. Other Concerns

The OAG raised additional issues regarding Otter Tail's CCOSS, including the following:

Discovery: Otter Tail's CCOSS relies on accounting data. The OAG alleged that Otter Tail did not always identify the relevant account in FERC's Uniform System of Accounts from which any given piece of data came, and the task of obtaining this data from Otter Tail was needlessly burdensome. As a remedy, the OAG asks the Commission to direct Otter Tail to include FERC account information within its CCOSS models in the next rate case.

Modeling: The OAG alleged that parts of Otter Tail's CCOSS contain numbers that would appear to be endogenous, arising from the model, but were in fact "hard-coded" into the model. As a result, when changes would be made to the model, the hard-coded data would not reflect these changes, causing needless frustration to the parties. The OAG asked the Commission to direct Otter Tail to correct these errors by the time it files its next rate case.

Peak Demand Allocator: Otter Tail calculates an allocator which identifies each class's share of usage on Otter Tail's system during periods of peak demand on Otter Tail's system. Generally, a utility's system's peak demand is a relevant design criteria, because it is the period when the demands of the utility's customers may threaten to exceed the utility's capacities. But Otter Tail is a member of MISO and its energy markets and, while the period of peak demand on Otter Tail's system is in the winter, MISO's peak demand occurs in the summer. As a consequence, MISO tends to have excess capacity at precisely the time that Otter Tail would be most likely to need it.

The actual period when capacity might be scarce is during MISO's peak demand, not Otter Tail's. MISO's rules for ensuring that the system will have adequate capacity during peak demand conditions are designed around MISO's peak demand, not Otter Tail's. As a result of these rules, Otter Tail incurs costs based on the amount of consumption on its system during MISO's peak demand, not Otter Tail's. For these reasons, the OAG argued, Otter Tail should calculate its peak demand allocator during MISO's peak, not Otter Tail's. The OAG asked the Commission to direct Otter Tail to calculate its allocator in accordance with MISO's resource adequacy rules by the time Otter Tail files its next rate case.

Advanced Meters: Otter Tail treats the cost of advanced meters capable of two-way communication—including Residential–Controlled Demand (RCD) meters and any other customers that have radio load-management receivers—as customer costs. But the OAG observed that utilities invest in advanced meters in order to facilitate conservation and load-shifting, matters that are related to energy and demand, respectively. Consequently the OAG asked the Commission to direct Otter Tail to allocate its cost of advanced meters equally to customer, energy, and demand.

3. The Department

The Department recommended that the Commission either accept Otter Tail's proposed CCOSS, adjusted to reflect the OAG's classification of conservation-improvement-program expenses, or develop a study based on the Zero Intercept method set forth in the Electric Manual. The Department also recommended that Otter Tail adjust its CCOSS to reflect exclusion of CIP expenses.

According to the Department, the distribution system exists to serve two functions: delivering service to customers' premises (customer costs), and ensuring that the distribution system is large enough to maintain reliable service (demand costs). Based on this view of the role of the distribution system, the Department is skeptical of any theory that would allocate distribution costs based on energy consumption.

Finally, the Department did not recommend setting rates on the basis of multiple CCOSS models. The Department recommended that the Commission adopt the model that it thinks best reflects cost causation. That said, the Department stated that it could support consideration of either or both of the cost methods reflected in the Electric Manual—the Minimum System method and the Zero Intercept method.

4. The Chamber

The Chamber also supported allocating costs guided by Otter Tail's CCOSS.

The Chamber opposed relying on the Basic System and Peak-and-Average methods. The Chamber argued that these methods would fail to allocate costs to customer classes on the basis of cost causation, and would be inconsistent with prior Commission orders. The Chamber expressed concern that these methods would allocate excessive costs to Otter Tail's commercial and industrial customers, would could make their operations uncompetitive with firms operating in an environment with cheaper electricity.

If the Commission were to adopt any or all of the OAG's CCOSS methods, the Chamber would ask that Otter Tail apply those methods not merely for the purpose of allocating distribution plant, but for allocating generation/production plant, too. The Chamber anticipated that allocating the cost of production plant in this manner would shift costs away from commercial and industrial customers.

D. Commission Action

Each CCOSS in the record supports a different conclusion about the appropriate allocation of cost responsibility among Otter Tail's customer classes, as follows:

Class	**Current Apportionment**	**Minimum System CCOSS**	**Basic System CCOSS**	**Peak & Average CCOSS**
Residential	24.67%	26.26%	24.58%	24.55%
Farms	1.59%	1.57%	1.59%	1.53%
General Service	15.95%	15.22%	15.25%	15.11%
Large General Service	50.04%	48.60%	49.63%	50.67%
Irrigation	0.20%	0.26%	0.28%	0.22%
Lighting	1.45%	1.50%	1.52%	1.50%
Other Public Authority	0.80%	0.83%	0.83%	0.83%
Water Heating Class	0.83%	1.07%	1.17%	1.04%
Controlled Service - Interruptible	3.64%	3.91%	4.31%	3.76%
Deferred Load Service	0.82%	0.78%	0.84%	0.78%
Total	**100%**	**100%**	**100%**	**100%**

Based on the arguments of the parties, the Commission concurs with Otter Tail, the Department, the Chamber, and the ALJ that the Minimum System method is a sound basis for allocating costs among customer classes, recognizing that the number of customers as well as the amount of peak consumption influence the cost of Otter Tail's distribution plant. The Commission also concurs with all parties on the need to re-classify CIP expenditures as energy-related costs rather than customer-related costs.

However, the Commission also concurs with the OAG on the merits of considering more than one cost study. The Electric Manual indicates that no single cost study method can be judged superior to all others in all contexts, and the choice among methods is fraught with disputes over assumptions, applications, and data.

Therefore the Commission concludes that Otter Tail's Minimum System method (modified to treat the costs of Conservation Improvement Programs as energy-related costs) provides a useful tool for apportioning Otter Tail's revenue requirement among customer classes in this proceeding. But so does the OAG's Basic System method, and its Peak and Average method. While evaluating data from a variety of models will not eliminate any model's weaknesses, it may provide a broader range of perspectives from which to evaluate the other models.

For this reason, the Commission will also direct Otter Tail, in its next rate case, to file CCOSSs using each of the methods described above—as well as the Zero Intercept method set forth in the Electric Manual.

The Zero Intercept method is similar to the Minimum System method, but through the use of statistical analysis it estimates the cost of a minimum system that is so small as to connect to all customers, yet have no actual capacity to transmit energy. In this manner the Zero Intercept method is intended to perfectly distinguish between the cost of connecting customers (a customer-related cost) from the cost of having capacity to provide electrical service to those customers (a demand-related cost).

During hearings, the parties acknowledged that conducting a Zero Intercept CCOSS would require Otter Tail to refine its data, but noted that the Company would be able to use this disaggregated data to improve its Minimum System study as well. At least for purposes of Otter Tail's next rate case, the Commission will direct the Company to refine its data and conduct additional analysis.

Finally, to address some of the challenges the OAG encountered in analyzing Otter Tail's CCOSS in this case, the Commission will also direct Otter Tail to take certain additional steps in its next rate case.

Specifically, Otter Tail must work with the OAG to update its CCOSS to address the discovery and modeling issues raised by the OAG in this proceeding. Similarly, Otter Tail must revise the method by which it calculates its peak demand allocator—whether based on a single summer peak, or a peak season—to reflect the peak demand as specified in MISO's policies governing resource adequacy. And Otter Tail must justify (and revise, if appropriate) its policies regarding the classification and allocation of advanced meters, Residential–Controlled Demand meters, or any other meters with radio load-management receivers.

XXVII. Sales Forecast

A. Introduction

When setting a utility's rates, the Commission must rely on an estimate of sales of utility service. These estimates influence the calculation of a utility's revenues and costs. They influence the Class Cost-of-Service Studies, discussed above. And they influence the calculation of the final rates to permit a utility to recover its costs.

B. Positions of the Parties

The Department found Otter Tail's data analysis and forecast to be deficient for a variety of technical reasons.

In particular, the Department recommended that Otter Tail make two specific changes to how it conducts its next sales forecast. First, the Department recommended that Otter Tail provide spreadsheets that tie the Company's test-year customer counts to the test-year meter counts. These counts are not the same, as some customers have multiple meters. In the interest of full analysis, and given some of the challenges in the current docket, the Department proposed that Otter Tail provide this information in its pre-filed forecasting data.

Second, the Department recommended that Otter Tail not wait until the end of the calendar year to correct its data collection and billing system data when the Company is planning to file a rate case. The Department acknowledged that errors will occur in historical data, but asked Otter Tail to make an extra effort to find and correct those errors before filing a rate case. Specifically, the Department emphasized that when errors are found, the errors should be corrected in the data for the month where the error occurred—not in the month when the error was discovered.

Otter Tail disagreed with aspects of the Department's critique. But Otter Tail agreed, for purposes of the current case, not to dispute the reasonableness of the Department's sales and revenue figures set forth in surrebuttal testimony.

C. The Administrative Law Judge's Report

The Administrative Law Judge's Report did not state specific findings on this issue.

D. Commission Action

The Commission concurs with the Department that the shortcomings in Otter Tail's sales analysis and forecasting, set forth in the attached supplementary findings, rendered the Company's testimony unreliable. And, consistent with the positions of Otter Tail and the Department, the Commission will rely on the test-year sales and revenue analysis and figures set forth in the Department's corrected surrebuttal testimony instead.

So for purposes of this rate case, the Commission finds test-year sales of 2,640,367,131 kWh, resulting in base test-year revenues of $173,461,633, and reducing the Company's test-year energy expense by $31,372.

In addition, the Commission will direct Otter Tail to do the following for its next rate case:

- In its pre-filed forecasting data, Otter Tail should provide an analysis with fully linked spreadsheets that tie together the Company's test-year customer counts and test-year meter counts.
- Prior to the initial filing and completion of future rate-case forecasts, Otter Tail should correct the data from its data collection and billing system in the same manner that it does at the end of each calendar year. If Otter Tail uses actual data in the base year as it did in this case (i.e., through August 2015), then Otter Tail should ensure that, to the fullest extent possible, all billing or other errors are corrected before the Company files its next general rate case. Moreover, Otter Tail should make such corrections to the month(s) in which the error occurred rather than the month when the error was discovered.

RATE DESIGN ISSUES

XXVIII. Interclass Revenue Apportionment

A. Introduction

The next step in rate design is to determine the share of the utility's revenue requirement to recover from each customer class. Otter Tail, the Chamber, the Department, and the OAG all agree that the Commission should consider the cost Otter Tail incurs to provide service to each class, as reflected in a CCOSS, as a principal factor in apportioning revenue responsibility. And these parties also agree that cost should not be the Commission's sole consideration. But the parties disagree about the method to calculate a CCOSS, and about the weight to be given to cost and non-cost factors.

B. Positions of the Parties

The parties' positions on revenue apportionment are reflected in the following table:

Class	Current Apportionment	Proposed Apportionment			
		Otter Tail	Chamber	Dept.	OAG
Residential	24.67%	25.05%	25.86%	24.67%	24.66%
Farms	1.59%	1.58%	1.58%	1.57%	1.59%
General Service	15.95%	15.84%	15.41%	15.72%	15.87%
Large General Service	50.04%	49.67%	48.96%	50.04%	49.99%
Irrigation	0.20%	0.22%	0.24%	0.21%	0.22%
Lighting	1.45%	1.49%	1.48%	1.50%	1.50%
Other Public Authority	0.80%	0.82%	0.82%	0.83%	0.83%
Water Heating Class	0.83%	0.85%	1.01%	0.87%	0.85%
Controlled - Interruptible	3.64%	3.70%	3.84%	3.81%	3.71%
Deferred Load Service	0.82%	0.78%	0.79%	0.78%	0.79%
Total	**100%**	**100%**	**100%**	**100%**	**100%**

1. The Chamber

The Chamber stated that it developed its proposal by relying on the Company's Minimum System CCOSS, to the exclusion of any other cost study, and generally by shifting each class's apportionment to be closer to the amount specified in the cost study. Of the four parties participating in this issue, the Chamber adhered most closely to the results of a CCOSS. The Chamber also proposed the greatest increase to the Residential class's share of costs, and the greatest decrease to the Large General Service class's share.

2. Otter Tail

Similar to the Chamber, Otter Tail also relied on its Minimum System CCOSS to the exclusion of the other cost studies in the record. And while Otter Tail also proposed to shift the apportionments closer to the levels set forth in its CCOSS, it proposed smaller shifts than the Chamber. Otter Tail argued that its proposal strikes the appropriate balance between adopting a cost-based apportionment as reflected in the Minimum System CCOSS, and addressing non-cost factors such as maintaining continuity with the existing apportionment.

3. The Department

Like Otter Tail and the Chamber, the Department stated that it developed its apportionment proposal guided by no other cost study than Otter Tail's. However, the Department also emphasized the need to balance respect for the cost study with respect for statutory duties to avoid unreasonable discrimination, to encourage energy conservation and the use of renewable sources of energy, to consider customers' ability to pay, and to resolve doubts as to reasonableness in favor of the customer.

The Department followed certain guidelines when developing its recommendation for revenue apportionment. The Department was willing to propose that certain classes begin bearing the full apportionment proposed by the CCOSS. In particular, two rate classes—Controlled Water Heat and Interruptible—contain customers who are willing to endure service interruptions if the price is right; the Department favored setting the apportionments for these classes at cost in order to provide the most authentic price signal. But out of concern for rate shock, the Department was unwilling to recommend increasing any class's apportionment by more than 15%. Finally, the Department proposed holding constant the apportionments to the Residential and Large General Service rate classes. The Department still proposed to increase the revenue requirements for these classes, but only at the rate that the utility's overall revenue requirement increased.

The Department acknowledged that, methodological differences notwithstanding, the Department's proposed apportionment closely matched the OAG's.

4. The OAG

The OAG stated that it was the only party to develop its proposed apportionment based on all three CCOSSs in the record. The OAG stated that it developed its proposal by seeking out patterns among the studies, including customer classes that all the studies identified as bearing too much revenue responsibility, or bearing too little. The OAG also identified classes that a majority of the studies identified as bearing too much cost, or too little. (The Residential Class was among those classes.) The OAG then proposed apportionments to bring each of these classes closer to the apportionments indicated by all or most of the studies.

The OAG opposed the apportionments recommended by Otter Tail and the Chamber, each of which proposed to increase the Residential Class's revenue apportioned above the current apportionment, and above the apportionments supported by two of the three CCOSSs in the record. But the OAG found the Department's proposed apportionment to be reasonable in result, even if the OAG did not embrace the Department's analytical methods.

C. The Administrative Law Judge's Report

The ALJ stated that, while the Commission has the authority to design rates on the basis of its quasi-legislative judgments, the ALJ was reluctant to exercise similar prerogatives. Instead, the ALJ sought to act on the basis of the preponderance of the evidence in the record, and declined to give weight to witness opinions—including, in particular, opinions about how ratepayers might react to large shifts in rates.

Based on this analysis, the ALJ recommended that the Commission adopt the revenue apportionment proposed by the Chamber. Because this allocation most closely conformed to Otter Tail's CCOSS, the ALJ concluded that it was reasonable, transparent, well-grounded in the record, and made the most progress in reducing inter-class subsidies and contributing to near-term stability in electricity rates.[85]

D. Commission Action

All parties have made credible and well-supported proposals for apportioning Otter Tail's revenue requirement. Nevertheless, the Commission finds the OAG's proposal has the greatest support. This proposal has the advantage of incorporating insights from three distinct cost studies. It generally brings customer classes closer to bearing their appropriate burdens, but does so in a gradual manner that is less likely to provoke ratepayers. And the fact that it closely tracks the apportionment advocated by the Department further bolsters its credibility.

Consequently the Commission will direct Otter Tail to design rates based on the OAG's proposed apportionment, set forth above.

XXIX. Revenue Decoupling

A. Introduction

Under traditional rate design, when ratepayers buy more energy than forecast, they pay higher bills than expected and the utility receives higher revenues. Conversely, when ratepayers buy less energy than forecast, they pay lower bills than expected and the utility receives less revenue than expected. This dynamic produces two consequences. First, the utility and ratepayers both bear the risk that sales will differ from the forecast. Second, while the Legislature directs the Commission to encourage energy conservation and efficiency, this rate design creates a disincentive for utilities to pursue policies that would decrease energy sales.

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[85] ALJ's Report at ¶ 516.

Revenue decoupling is a type of rate design intended to align the interest of the utility and the public by severing the connection between energy sales and net revenue. Consistent with statute, the Commission has established standards for decoupling mechanisms that would operate "without adversely affecting utility ratepayers,"[86] and has authorized some three-year pilot programs implementing decoupling.[87]

In general terms, revenue decoupling operates by having the Commission identify the revenues a utility should recover. If a utility's revenues later exceed this revenue requirement, the difference is returned to ratepayers in the form of a discount on the price of future energy consumption. If the revenues fall short of the revenue requirement, the difference is made up via a surcharge on future energy consumption. In this manner, the utility receives—and ratepayers pay—the amounts justified in the rate case.

B. Positions of the Parties

1. Fresh Energy

Fresh Energy recommended that the Commission direct Otter Tail to implement revenue decoupling.

Otter Tail recovers its costs of service via a two- or three-part rate. One part may increase or decrease with the passage of time (the fixed monthly charge, or customer charge). Another part increases as the amount of energy (kWhs) consumed increases (the energy or volumetric charge). And for larger customers, Otter Tail also has another bill part that increases as a customer's maximum demand increases (the demand charge).

Fresh Energy favors a rate design whereby Otter Tail would recover its costs based largely on volumetric charges, on the theory that such charges provide a customer with the maximum incentive to pursue conservation efforts—for example, by turning off lights or investing in more efficient electric appliances. In contrast, utilities often prefer a rate design that recovers a larger share of costs via fixed charges to help stabilize utility revenues even when energy sales are low. But a rate design with higher fixed charges will have lower volumetric charges, all else being equal, frustrating Fresh Energy's objectives. So to remove any concern about stabilizing revenues, Fresh Energy advocates revenue decoupling.

Because this rate design helps assure a utility that it will recover the amount of revenues authorized by the Commission, this rate design reduces the need for other revenue-stabilizing strategies such as higher fixed monthly customer charges.

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[86] *See* Minn. Stat. § 216B.2412, subd. 2; *In the Matter of a Commission Investigation Into the Establishment of Criteria and Standards for the Decoupling of Energy Sales from Revenues*, Docket No. E,G-999/CI-08-132, Order Establishing Criteria and Standards to be Utilized in Pilot Proposals for Revenue Decoupling (June 19, 2009) (Decoupling Order).

[87] *See* Minn. Stat. § 216B.2412, subd. 3 (authorizing pilot programs).

Even if the Commission were not persuaded to adopt revenue decoupling in the current rate case, Fresh Energy asked the Commission to direct Otter Tail to implement decoupling in its next rate case—or earlier.

2. OAG

The OAG supported Fresh Energy's proposal—on the condition that the Commission add some conditions that it has included when approving other revenue-decoupling mechanisms. These included a prohibition on rate surcharges if Otter Tail fails to demonstrate that it has achieved specified levels of conservation, a presumption that revenue decoupling would apply to the Large General Service class, and a limit on increases in certain customer charges until after "a stakeholder process to research alternative rate designs."[88]

Fresh Energy supported these conditions.

3. Otter Tail

Otter Tail has agreed to work with the parties to research and propose alternative rate designs prospectively. But Otter Tail opposed Fresh Energy's proposal—not out of opposition to revenue decoupling in general, but out of concerns of adopting the practice in the context of the current proceeding.

As previously discussed, Otter Tail and the Department arrived at different forecasts of Otter Tail's future sales. While Otter Tail ultimately decided not to contest the Department's forecast for purposes of setting rates in this proceeding, the Company expressed concern that a misguided sales forecast might cause a revenue-decoupling mechanism to trigger substantial surcharges.

C. The Recommendation of the Administrative Law Judge

The Administrative Law Judge recommended that the Commission deny Fresh Energy's recommendation to implement revenue decoupling. Based on the Commission's order establishing standards for adopting revenue decoupling,[89] the ALJ found that the Commission had placed the burden of justifying a decoupling proposal on the party making the proposal—in this case, on Fresh Energy. And the ALJ concluded that the record in this docket left too many matters unresolved to find that Fresh Energy had borne its burden.[90]

D. Commission Action

The Commission appreciates Fresh Energy's arguments in support of revenue decoupling. The Commission is already persuaded of the merits of revenue decoupling generally, as demonstrated by its prior decisions approving this rate design, and no party to the current proceeding has opposed it. Thus, the issue before the Commission is not the merits of revenue decoupling generally, but as applied to Otter Tail in the current docket.

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[88] OAG's Initial Brief, at 91.

[89] *See* Decoupling Order, *supra*.

[90] ALJ's Report ¶¶ 609–614.

As Fresh Energy observes, revenue decoupling is designed to remove a utility's disincentive to pursue conservation. But in this case, the record reveals that Otter Tail has been diligent in pursuing conservation efforts and achieving conservation targets. It is unclear how much more conservation the Commission should expect from a change in rate design.

Moreover, as Otter Tail argued, the size of a decoupling mechanism's surcharges and refunds will depend on the accuracy of a utility's sales forecasts. All forecasts are inaccurate because the future is uncertain. But a recent surge in sales resulting from one specific customer has complicated the ability to anticipate future growth rates, as reflected in the disputes between Otter Tail and the Department.

In sum, Otter Tail is already demonstrating an admirable commitment to conservation, while the record poses an unusual challenge for forecasting Otter Tail's future sales. For these reasons the Commission will adopt the ALJ's recommendation and decline to compel Otter Tail to implement revenue decoupling at this time.

Instead, the Commission will accept Otter Tail's offer to research alternative rate design—and to work with stakeholder groups in this effort—culminating in an alternative rate design proposal.

Specifically, by April 1, 2018, Otter Tail must prepare a report analyzing the potential customer impacts of Fresh Energy's proposed revenue-decoupling mechanism for the Residential, Farm, and Small General Service rate classes. The report must include a comparison of actual 2016 and 2017 revenues to 2016 Test Year baseline revenues (with baseline revenue per customer calculated using the final rates, sales, and customer counts of this rate case). And it must include a comparison of actual 2014 and 2015 revenues to 2009 baseline revenues (baseline revenue per customer calculated using the final rates, sales, and customer counts from Otter Tail's 2010 rate case[91]).

Interested parties will be invited to file comments on the report to address how any proposed change would affect specific customers or classes, and potential strategies for implementing a decoupling mechanism for Otter Tail, among other matters.

XXX. Monthly Customer Charge

A. Introduction

As previously discussed, Otter Tail assesses charges to members of each customer class based on a two- or three-part rate. One part consists of a fixed monthly customer charge, designed to recover the fixed costs of serving a customer. Another part consists of a distribution charge that varies with the amount of electricity a customer uses. And for certain classes of larger customers, Otter Tail also assesses a monthly demand charge reflecting the peak amount of electricity the customer uses.

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[91] *In the Matter of the Application of Otter Tail Power Co. for Authority to Increase Rates for Electric Service in Minnesota,* Docket No. E-017/GR-10-239.

The forecasted sum of the revenues from a class's customer charge, distribution charge, and demand charge must equal the class revenue apportionment. Thus rate design poses a tradeoff: the choice to reduce any one component of these charges must result in an increase to another component. For customers that do not pay a separate demand charge—such as residential customers—an increase in the customer charge will have the effect of reducing the volumetric distribution charge, and vice versa.

In the absence of revenue decoupling, utilities generally favor increased customer charges to make total bills and revenue collections more stable by reducing the share of a class's revenue requirement to be recovered on the basis of energy consumption, which varies month to month.

B. Positions of the Parties

1. Otter Tail

Otter Tail proposed increasing its schedule of fixed customer charges, including the following:

Proposed Fixed Charge Increases ($/month)

Class	Current	Proposed	Increase
Residential	$8.50	$13.30	56%
Residential—Controlled Demand	$11.00	$17.00	55%
Small General	$15.50	$21.50	39%
General (secondary)	$19.00	$35.00	84%

Otter Tail noted that once the Commission establishes the amount of money each customer class must contribute toward covering the utility's revenue requirement, rate design becomes a zero-sum exercise for a customer class: a change in any one rate component—say, an increase in the customer charge—must be offset by an opposite change in another component—say, a decrease in the volumetric rate.

But while changes in billing components cannot change the class's revenue requirement, these changes can change how much individual members of the class contribute toward reaching the revenue requirement. A rate design with higher customer charges and lower volumetric charges will decrease the bills for households with higher consumption and increase the bills for households with lower consumption. A rate design with lower customer charges and higher volumetric charges would have the opposite result. Otter Tail characterized these differences as *intra-class subsidies*.

Generally Otter Tail sought to set fixed customer charges to recover fixed components of providing service, as established in Otter Tail's incremental cost study. Otter Tail argued that this provided a cost-based method for determining the appropriate tradeoff between larger fixed charges and larger volumetric charges.

While other parties objected that Otter Tail's proposals would result in an excessively large increase in the monthly customer charge, especially for the Residential Class, Otter Tail argued that these concerns were misplaced. Otter Tail reasoned that the choice to moderate the increase in the customer charge necessarily entails a choice to enhance the increase in the volumetric rates. The customer class would bear the increased costs, regardless.

In support of its proposed rate design, Otter Tail documented how its service area differs from the service areas of other utilities. Otter Tail serves relatively small communities—many lacking access to natural gas. People who heat with electricity will consume more electricity than people who heat with gas, all else being equal, and thus would bear a greater burden if the Commission were to set the volumetric charge high and the customer charge low.

In the absence of rate decoupling, Otter Tail emphasized the role of fixed customer charges in helping utilities and ratepayers stabilize the size of bills, and thus stabilize the utility's revenues. Recovering fixed costs via volumetric rates can have the effect of discouraging energy consumption, which can have the effect of depriving a utility of the opportunity to recover its fixed costs. Thus Otter Tail concluded that raising customer charges, and lowering the volumetric rate, complies with the statutory directive to encourage conservation to the maximum reasonable extent—because other rate designs simply are not reasonable.

In any event, Otter Tail cited evidence questioning the degree to which customers, especially residential customers, change their consumption of electricity in response to changes in the volumetric charge—at least regarding the magnitude of changes under discussion here.

Otter Tail argued that the atypical nature of its service area means that its residential customers are at unusual risk from intra-class subsidies. First, Otter Tail serves a higher percentage of low-income residential consumers than do other Minnesota utilities and, according to the Company, low-income households tend to consume more electricity than others. Second, Otter Tail serves a higher percentage of people living in smaller towns, especially towns without natural gas service; people who heat with electricity tend to consume more electricity than others. In each of these cases, customers would benefit from lower volumetric rates, even at the expense of higher fixed customer charges.

According to Otter Tail, intra-class subsidies also arise between single-family and multifamily residences, between urban and rural areas, and between customers with distributed generation—rooftop solar panels, for example—and customers without such generators.

Finally, Otter Tail addressed the special circumstances of households receiving Residential–Controlled Demand service. Subscribers to this service agree, in exchange for lower rates, to permit the Company to place limits on electric usage during winter months when Otter Tail's system faces peak demand. Because customers who subscribe to this service must have a more sophisticated meter than customers who subscribe to standard Residential Service, and because Otter Tail classifies meters as a customer charge, this justifies assessing a higher customer charge on the Residential–Controlled Demand class than on the Residential Class.

2. The Department

The Department proposed the following changes to Otter Tail's fixed customer charges:

Class	Current	Proposed
Residential	$8.50	$9.75
Residential–Controlled Demand	$11.00	$12.75
Small General	$15.50	$18.50
General (secondary)	$19.00	$27.00

The Department supported increasing these four customer charges to bring them closer to the marginal cost of service, and to mitigate intra-class subsidies. But the Department could not support the magnitude of the Company's proposed increases in the customer charge, which the Department found to be inconsistent with past Commission practice. While rural electric cooperatives might assess comparable customer changes, the Department argued that these cooperatives did not provide an appropriate basis for comparison with a regulated public utility. And the Department argued that the magnitude of the increases would provoke rate shock among Otter Tail's ratepayers.

Moreover, the Department argued that Otter Tail's arguments about the adverse consequences of intra-class subsidies could be overstated. The Department's own analysis confirmed that residential consumers did not substantially alter their consumption of electricity in response to a price change, and that this pattern prevailed even among low-income consumers.

3. The OAG

The OAG proposed the following schedule of fixed customer charges:

Class	Current	Proposed
Residential	$8.50	$8.50
Residential—Controlled Demand	$11.00	$11.00
Small General	$15.50	$14.00

That is, the OAG proposed retaining the existing schedule for the Residential and Residential–Controlled Demand classes, and decreasing the fixed customer charge for the Small General Service class.

The OAG repeated its traditional arguments in favor of lower customer charges even at the expense of higher volumetric charges: Increasing fixed charges while reducing the charge for each additional kilowatt-hour sold has the effect of undermining conservation efforts. If Otter Tail eventually must add new facilities to meet demand because the Company failed to achieve all of the available potential for conservation, ratepayers will have to bear the additional cost.

But in this case, the OAG raised additional arguments for its preference for lower customer charges.

The OAG did not disagree with Otter Tail's theory to adjust fixed customer charges to more closely match a customer's marginal cost. But the OAG argued that Otter Tail should have calculated marginal cost to exclude costs related to Conservation Improvement Programs, which the parties agree should be characterized as energy costs, not customer costs. And it should have calculated marginal costs using the New Customer Only method. Had it done so, Otter Tail would have concluded that the Residential class was already paying customer charges that roughly match the class's marginal cost—and Otter Tail would have realized that the Small General Service class was paying customer charges well in excess of its marginal cost. For these reasons, the OAG proposed keeping the Residential Class's customer charge constant, and reducing the charge for the Small General Service Class.

Regarding the Residential–Controlled Demand class, the OAG argued that the marginal cost calculation was artificially inflated by Otter Tail's choice to treat the class's extra meter costs as customer-related costs. The OAG argued that this class exists in order to provide Otter Tail with a means to manage demand and energy consumption of these customers during periods of peak demand. In other words, the OAG argued, the added metering cost should have been treated as demand- and energy-related costs. Indeed, the OAG suggested that the needlessly inflated customer charge may be reducing the efficiency of Otter Tail's system by needlessly deterring customers from subscribing for this beneficial kind of residential service.

According to the OAG, if Otter Tail were to remove these added metering costs from its customer charge calculation—and instead recover these costs via the volumetric charge—it would eliminate the rationale for increasing this class's customer charge.

The OAG acknowledged Otter Tail's arguments about how the demographics of its service area would affect the Company's cost of service and marginal cost calculation. But the OAG argued that these factors were already accounted for in Otter Tail's analysis and do not warrant additional consideration.

4. Fresh Energy

Fresh Energy proposed maintaining the current fixed customer charge for the Residential class:

Class	Current	Proposed
Residential	$8.50	$8.50

Fresh Energy claimed that Otter Tail failed to show that its proposed increases to the Residential customer charge would be reasonable for all residential customers.

Fresh Energy concurred in many of the arguments of the Department and the OAG. For example, Fresh Energy agreed with the Department's rejection of using rural electric cooperatives as an appropriate basis for comparison for Otter Tail's rates. And Fresh Energy echoed the OAG's criticism of Otter Tail's marginal cost study. In addition, while Otter Tail argued that the existing rate design was creating intra-class subsidies, Fresh Energy argued that all rate designs have this result: It is an inevitable result of designing a set of rates that will apply uniformly to a heterogeneous population.

C. The Recommendation of the Administrative Law Judge

The ALJ found that a marginal cost study provides relevant guidance for setting customer charges. And the ALJ concluded that the marginal cost study conducted by Otter Tail provided more relevant guidance for setting customer charges than the analysis conducted by the OAG using the New Customers Only method.

While the ALJ acknowledged in the abstract the Department's concern that large increases in customer charges might provoke rate shock among ratepayers, the ALJ concluded that the record contained insufficient evidence to credit this concern.

Consequently the ALJ recommended adoption of Otter Tail's proposed customer charges for the Residential, Residential–Controlled Demand, Small General Service, and General Service (Secondary) classes, on the theory that these changes would better permit the Company to recover its fixed costs from these customers.[92]

D. Commission Action

The Commission appreciates the rigor with which the parties have analyzed the magnitude of the monthly customer charge. The parties largely agreed on the merits of setting a fixed customer charge to permit a utility to recover its marginal cost to serve customers. But the parties disagreed about the best method for calculating that amount, and about the wisdom of implementing large changes in customer charges.

As a general proposition, the Commission concurs with the ALJ that Otter Tail's marginal-cost analysis provides an appropriate benchmark for guiding the level of customer charges. Like the ALJ, the Commission is not persuaded that the New Customer Only method is appropriate for identifying the marginal cost of all the customers within any given customer class.
The Commission agrees that Conservation Improvement Program costs should not be included in a calculation of a customer's marginal cost to Otter Tail's system, but Otter Tail made some adjustments related to this already; it does not appear that any additional adjustments, if warranted, would substantially change Otter Tail's analysis.

That said, at this time the Commission will decline to adopt Otter Tail's schedule of customer charges for the Residential, Residential–Controlled Demand, Small General Service, and General Service (Secondary) classes, for reasons articulated by the OAG and the Department.

First, as the OAG noted, the added meter costs borne by subscribers to the Residential–Controlled Demand service are more appropriately understood as demand or energy costs. These costs are incurred to benefit Otter Tail's system as a whole, not just the customer receiving electricity through the meter. Consequently the Commission concludes that they should be excluded from any calculation of these customers' marginal cost. And when these sums are excluded, the record no longer demonstrates any need to increase the customer charge for this customer class. Consequently the Commission will not authorize any increase for this customer

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[92] ALJ's Report ¶¶ 531, 582, 593, 597, 598, 602, and 604.

charge. Rather, the Commission will direct Otter Tail to abolish its fixed facility charge for this class, and to recover the additional cost of the relevant facilities via volumetric rates instead.

Second, the Commission concurs with the Department that, no matter how thoroughly Otter Tail calculated the marginal costs of serving the Residential, Small General Service, and General Service (Secondary) classes, the magnitude of the proposed increases are likely to provoke adverse customer reaction. Unlike the ALJ, the Commission acknowledges the expert judgment of the Department witnesses on this topic and finds it credible. Consequently the Commission is persuaded to moderate the proposed increases in the customer charge for these three customer classes in the manner proposed by the Department. Again, Otter Tail will not be deprived of the opportunity to recover its costs; it will simply recover them via the volumetric charge.

FINANCIAL SCHEDULES

XXXI. Gross Revenue Deficiency

The above Commission findings and conclusions result in a Minnesota-jurisdictional gross revenue deficiency for the test year of $12,292,120, as shown below:

Revenue Deficiency - Minnesota Jurisdiction
Test Year Ending December 31, 2016

Description		OTP - MN
Average Rate Base	$	487,191,827
Rate of Return		7.5056%
Required Operating Income	$	36,566,670
Operating Income	$	29,359,798
Income Deficiency	$	7,206,872
Gross Revenue Conversion Factor		1.705611
Gross Revenue Deficiency	$	12,292,120

XXXII. Rate Base Summary

Based on the above findings, the Commission concludes that the average Minnesota-jurisdictional rate base for the test year ending December 31, 2016, is $487,191,827, as shown below:

Rate Base Summary - Minnesota Jurisdiction
Test Year Ending December 31, 2016

Description	OTP-MN
PLANT IN SERVICE	
Production	$ 469,760,408
Transmission	$ 201,194,619
Distribution	$ 206,480,733
General	$ 43,721,118
Intangible	$ 4,989,475
Total Plant In Service	$ 926,146,353
RESERVE FOR DEPRECIATION	
Production	$ (177,750,802)
Transmission	$ (56,199,220)
Distribution	$ (90,173,998)
General	$ (19,350,265)
Intangible	$ (2,461,530)
Total Reserve For Depreciation	$ (345,935,815)
NET PLANT IN SERVICE	
Production	$ 292,009,606
Transmission	$ 144,995,399
Distribution	$ 116,306,735
General	$ 24,370,853
Intangible	$ 2,527,945
Total Net Plant In Service	$ 580,210,538
OTHER RATE BASE ITEMS	
Utility Plant Held for Future Use	$ 13,813
CWIP	$ 11,833,565
Materials & Supplies	$ 9,408,253
Fuel Stocks	$ 5,824,626
Prepayments	$ 964,455

Customer Advances & Deposits	$	(1,034,563)
Cash Working Capital	$	4,756,352
Accumulated Deferred Income Taxes	$	(124,785,212)
Total Other Rate Base Items	$	(93,018,711)
TOTAL AVERAGE RATE BASE	$	487,191,827

XXXIII. Operating Income Summary

Based on the above findings, the Commission concludes that the Minnesota-jurisdictional net income for the test year under present rates is $29,359,798, as shown below:

Operating Income Summary - Minnesota Jurisdiction
Test Year Ending December 31, 2016

Description	OTP-MN
UTILITY OPERATING REVENUES	
Retail Revenue	$ 196,132,378
Other Operating Revenue	$ 7,109,372
Total Operating Revenues	$ 203,241,750
UTILITY EXPENSES	
Production	$ 86,806,274
Transmission	$ 6,792,776
Distribution	$ 7,562,530
Customer Accounting	$ 6,541,536
Customer Service & Information	$ 7,293,088
Sales	$ 108,214
Administrative & General	$ 18,694,465
Charitable Contributions	$ 15,927
Depreciation	$ 26,949,513
General Taxes	$ 7,326,510
Total Operating Expenses	$ 168,090,833
Net Operating Income Before Taxes & AFUDC	$ 35,150,917
TAXES	
Investment Tax Credit	$ (4,585,822)
Deferred Income Taxes	$ 3,205,425
Federal & State Income Tax	$ 7,762,686
Total Income Taxes	$ 6,382,289
Net Operating Income Before AFUDC	$ 28,768,628
AFUDC	$ 591,170
Net Income	$ 29,359,798

ORDER

1. The following capital structure and overall cost of capital are approved:

Component	Ratio	Cost	Weighted Cost
Long-Term Debt	44.0601%	5.6229%	2.4775%
Short-Term Debt	3.4399%	2.5549%	0.0879%
Common Equity	52.5000%	9.4100%	4.9403%
Total	100.000%		7.5056%

2. Otter Tail's proposal to recover airplane costs totaling $117,453 is approved.
3. Otter Tail shall provide more detailed, granular information on aircraft-related fixed costs and avoided costs of driving in future rate cases.
4. Otter Tail shall exclude the prepaid pension asset and OPEB liabilities and associated ADIT from test-year rate base.
5. The Commission accepts the parties' agreement to update the expected return on plan assets for qualified pension to 7.75% and update the census data for qualified pension, retiree medical, and LTD medical expense to January 1, 2016.
6. Otter Tail may use the 2012–2016 five-year average discount rates of
    a. 4.81% to calculate test-year pension expense, and
    b. 4.63% to calculate test-year OPEB expenses.
7. Otter Tail shall make the correct adjustments to total test-year pension and OPEB expenses, those in Operations and Management expenses, and the capitalized pension and OPEB expenses.
8. The Commission denies Otter Tail's request to charge unsubscribed energy costs associated with the Company's TailWinds program to non-enrolling customers through the Energy Adjustment Rider.
9. Otter Tail shall not include test-year reagent costs and emission allowances in the base fuel costs, or adjust test-year reagent costs and emission-allowance amounts through the fuel clause adjustment.

10. The ALJ Finding of Fact 229 shall be modified as follows:

> OTP's proposal to use the E8760 allocator to allocate both base fuel costs and amounts recovered through the Energy Adjustment Rider is reasonable and shall ~~should~~ be adopted. Further, OTP ~~should~~ shall only begin using the ~~10-class~~ E8760 allocation for the energy adjustment upon implementation of the new CIS in 2018. When the new system is operational, it would make allocations across the ten customer classes as recommended by the Department. Finally, OTP shall ~~should~~ submit a compliance filing at least 120 days ahead of the proposed implementation date of the new rates, consistent with the recommendation of the Department.

11. The Commission rejects ALJ Finding of Fact 219 and finds that the Cash Working Capital lag days for property taxes, Labor, and Associated Payroll Expense, and Tax Collections Available-Franchise Taxes should be adjusted as agreed upon between the Department and Otter Tail, and Cash Working Capital should be updated to reflect the Commission-approved expense levels.

12. The Commission will adopt the agreement between Otter Tail and the Chamber as follows:

> The appropriate base rate amount of SPP transmission-related expense in the test year shall be $530,000 with the differences accounted for in a tracker to track the amounts over and under on an annual basis. Otter Tail shall set up a tracker to track the amounts over and under the base amount of net costs on an annual basis.

13. Otter Tail may recover management-incentive costs in test-year expenses after removal of $170,079.

14. Otter Tail may recover the cost of the following donations in test-year expenses:

    a. $9,741 for the purchase of circus tickets and grills

    b. $221 for other events and services

15. The Commission adopts ALJ Finding of Fact 658, amended as follows:

> The Administrative Law Judge agrees and finds that OTP did not meet the presentation requirement. In its next rate case, it should produce a one-page summary of total amounts in each expense category~~ for the 2016 Test Year~~.

16. As agreed, Otter Tail shall refund any over-collection of Big Stone II generation-related development costs in its interim-rate refund.

17. The Commission adopts the Department's proposal to increase the PTCs in the 2016 test year and reduce OTP's tax expense by $76,828.

18. The Company is authorized to true up and recover the difference between its projected PTCs in base rates and its actual PTCs in its Renewable Rider prior to the PTCs' expiration.

19. Recovery of costs of the Integrated Transmission Service Agreement with MRES is limited to $182,500. If Otter Tail seeks recovery for such expenses in its future rate cases, Otter Tail shall provide additional detail justifying recovery.

20. The Commission does not adopt ALJ's Report ¶ 415. Otter Tail may recover 50% of its investor-relations expense.

21. ALJ's Report ¶ 444 is modified to exclude the recovery of Lignite Energy Council dues in the test year, as the Company has withdrawn that portion of its request. In future rate cases, if the Company seeks recovery of organizational dues of this nature, it must support its claim by providing information that identifies on membership invoices the amount of dues paid and the portion of dues charged for lobbying activities.

22. Regarding proration of Otter Tail's Accumulated Deferred Income Tax:

    A. The Commission accepts Otter Tail's agreement to extend the duration of this case, leaving the record open to receive future filings from Otter Tail and the parties on this topic. Otter Tail shall continue to charge interim rates subject to refund pending subsequent Commission action.

    B. By July 1, 2017, Otter Tail shall file a report apprising the Commission of the status of Otter Tail's request for a private letter ruling from the federal Internal Revenue Service (IRS), and summarizing Otter Tail's understanding of how the parties will implement the process set forth below.

    C. If by August 1, 2017, the IRS issues a private letter ruling in response to Otter Tail's request, then the following shall occur:

        1) Otter Tail shall make a filing within 15 days of the ruling that sets forth the details of the ruling and estimates how implementing the ruling would affect rates.

        2) The Commission will establish a deadline for parties to file replies to Otter Tail's analysis and proposal.

        3) Parties may file replies.

    D. If by July 31, 2017, the IRS has not issued its private letter ruling in response to Otter Tail's request, then Otter Tail shall do the following:

        1) By August 15, 2017, Otter Tail shall file its detailed proposal for implementing final rates calculated on the basis of prorated Accumulated Deferred Income Tax.

        2) Otter Tail shall record in its accounts a regulatory liability reflecting the difference between a revenue requirement including proration and a revenue requirement excluding proration.

        3) If the IRS ultimately issues a private letter ruling to Otter Tail that establishes that ratepayers paid excessive interim or final rates based on a misapplication of normalization requirements, then Otter Tail shall submit a detailed proposal for addressing the regulatory liability. Otter Tail shall file this proposal as part of Otter Tail's initial filing in its next rate case unless otherwise instructed by the Commission.

23. Regarding jurisdictional allocation of Multi-Value Projects, the Commission does not adopt ALJ's Report ¶¶ 287-294. Otter Tail shall use All-In allocation and include the Big Stone Area Transmission Lines in the Company's 2016 Transmission Cost Recovery Rider in Docket No. E-017/M-16-374, *In the Matter of the Petition of Otter Tail Power Company for Approval of Its Transmission Cost Recovery Rider Annual Adjustment*.

24. Regarding Class Cost of Service Studies, in its next rate case Otter Tail must take the following actions prior to and upon filing its embedded CCOSS:

    A. Work with the OAG to update its CCOSS to address the discovery and model issues raised by the OAG in this proceeding.

    B. Calculate Otter Tail's peak demand allocator to reflect MISO resource-adequacy rules, whether this be a single summer peak or a seasonal approach.

    C. Address the classification and allocation of advanced meters, Residential–Controlled Demand meters and any other customers that have radio load management receivers.

    D. File CCOSSs using the following methods:

    - The Basic System Method
    - The Peak and Average Method
    - The Zero Intercept Method
    - The Minimum System method, refined through the use of disaggregated data.

25. In designing rates, Otter Tail shall apportion revenue responsibility among its customer classes as follows:

Class	**Apportionment**
Residential	24.66%
Farms	1.59%
General Service	15.87%
Large General Service	49.99%
Irrigation	0.22%
Lighting	1.50%
Other Public Authority	0.83%
Water Heating Class	0.85%
Controlled - Interruptible	3.71%
Deferred Load Service	0.79%
Total	**100%**

26. Regarding decoupling,

A. Otter Tail shall research, work with stakeholder groups, and propose alternative rate designs.

B. Otter Tail shall prepare a report analyzing the potential customer impacts of Fresh Energy's proposed revenue-decoupling mechanism for the Residential, Farm, and Small General Service rate classes.

1) The report shall include at least the following:

- Comparison of actual 2016 and 2017 revenues to 2016 Test Year baseline revenues (with baseline revenue per customer calculated using the final rates, sales, and customer counts of this rate case); and
- Comparison of actual 2014 and 2015 revenues to 2009 baseline revenues (baseline revenue per customer calculated using the final rates, sales, and customer counts from Otter Tail's 2010 Rate Case (Docket No. E-017/GR-10-239)).

2) Otter Tail shall file the report by April 1, 2018.

3) Interested parties will be invited to file comments on the report addressing identified customer impacts, potential strategies for implementing a decoupling mechanism for Otter Tail, and other matters.

27. Regarding Otter Tail's rate design,

A. Otter Tail shall adopt the following schedule of fixed monthly customer charges:

Class	**Amount**
Residential	$9.75
Residential–Controlled Demand	$11.00
Small General Service	$18.50
General (secondary)	$27.00

B. Regarding Residential–Controlled Demand Service, Otter Tail shall abolish the fixed facilities charge and recover the costs for fixed facilities through the volumetric rate.

28. The Commission adopts the sales analysis and forecasting set forth in the Department's corrected surrebuttal testimony, and summarized in the attached supplementary findings on sales forecasts.

A. For purposes of setting rates, the Commission finds test-year sales of 2,640,367,131 kWh, resulting in base test-year revenues of $173,461,633, and reducing the Company's test-year energy expense by $31,372.

B. In its next rate case:

1) In pre-filed forecasting data, Otter Tail shall provide an analysis with fully linked spreadsheet that tie together the Company's test-year customer counts and test-year meter counts.

2) Prior to the initial filing and completion of future rate case forecasts, Otter Tail shall correct the data from its data-collection and billing system in the same manner that it corrects its data at the end of each calendar year. If Otter Tail uses actual data in the base year as it did in this case (i.e., through August 2015), then Otter Tail shall ensure that, to the fullest extent possible, all billing or other errors are corrected before the Company files its general rate case. Moreover, when an error is discovered, Otter Tail shall make the correction to the data for the month(s) in which the error occurred rather than the month(s) in which the error was discovered.

29. Otter Tail shall, in its next rate case, provide detailed information of all the costs necessary to obtain equity in its proposed test year, and its plans for acquiring equity through the capital markets for the five years following the test year. If the Company proposes adjustments to ROE for flotation costs, it shall compare its proposal to the required information.

30. Within 30 days, Otter Tail shall make the following compliance filings:

  a. Revised schedules of rates and charges reflecting the revenue requirement and the rate design decisions herein, along with the proposed effective date, and including the following information:

    i. Breakdown of Total Operating Revenues by type;

    ii. Schedules showing all billing determinants for the retail sales (and sale for resale) of electricity. These schedules shall include but not be limited to:

      1. Total revenue by customer class;

      2. Total number of customers, the customer charge and total customer charge revenue by customer class; and

      3. For each customer class, the total number of energy and demand related billing units, the per unit energy and demand cost of energy, and the total energy and demand related sales revenues.

    iii. Revised tariff sheets incorporating authorized rate design decisions;

    iv. Proposed customer notices explaining the final rates, the monthly basic service charges, and any and all changes to rate design and customer billing.

  b. A revised base cost of energy, supporting schedules, and revised fuel adjustment tariffs to be in effect on the date final rates are implemented.

    c. A summary listing of all other rate riders and charges in effect, and continuing, after the date final rates are implemented.

31. Otter Tail shall file a computation of the CCRC based upon the decisions made herein.

32. Otter Tail shall file a schedule detailing the CIP tracker balance at the beginning of interim rates, the revenues (CCRC and CIP Adjustment Factor) and costs recorded during the period of interim rates, and the CIP tracker balance at the time final rates become effective.

33. If final authorized rates are lower than interim rates, Otter Tail shall file a proposal to make refunds of interim rates consistent with the Commission’s decisions in this proceeding, including interest to affected customers.

34. Comments may be filed on all compliance filings within 30 days of the date they are filed. However, comments are not necessary on Otter Tail Power Company’s proposed customer notice.

34. This order shall become effective immediately.

BY ORDER OF THE COMMISSION

Daniel P. Wolf

Daniel P. Wolf
Executive Secretary

THE GREAT SEAL OF THE STATE OF MINNESOTA
1858

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In the Matter of the Application of Otter Tail Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota **Docket No. E-017/GR-15-1033**

SUPPLEMENTARY FINDINGS—SALES FORECAST

A. Overview of Test-Year Sales and Revenue Forecasts in Rate Cases

1. The test year is a representative 12-month period selected by the utility, which must be based on reasonable costs and revenues, to determine appropriate rates to be charged to customers. The costs and revenues are for a 12-month period, based on current utility circumstances, but the rate case is not a projection for an actual year; instead, the rates based on this information remain in place until the Commission approves new rates in a subsequent rate case. The representative values reflect known and measurable changes that are anticipated to occur and are adjusted to remove the impacts of variable factors, such as weather. Heinen Direct, at 32.

2. Test-year sales volumes are important factors in calculating a utility's revenue requirement because sales levels directly impact both revenues and expenses, and hence, the overall revenue requirement. Because sales levels are an integral input in calculating a utility's revenue requirement, the method used to determine sales levels must be reasonable. *Id.* at 33.

3. Several rate case issues are affected by the sales forecast. For example, in designing rates, test-year sales volumes are used to allocate costs in the CCOSS, which is one of the factors used to apportion revenue responsibility. In addition, the sales forecast is used to determine any rate that is designed to recover costs per unit of sales, such as per-kilowatt hour (kWh) rider rates. Thus, the sales forecast is used to set the individual tariffed rates when final rates are set.

4. When sales are under-estimated, a utility's revenue requirement is spread over fewer units (kWh), which means that the utility would collect more revenues per unit sold than is warranted by costs. That is, customers would pay a higher rate for this energy than is reasonable. The opposite would be true (i.e., rates would be too low) if the sales forecast were too high. Therefore, reasonable sales estimates and the methodologies used to determine sales levels are a critical part of the rate-case process.

B. Summary of Otter Tail's Test-Year Sales Methodology

5. Otter Tail filed a future, or forecasted, test year in this proceeding. Heinen Direct, at 34. This approach was a change from Otter Tail's past practice, where Otter Tail has used historical test-years, adjusted for known and measurable changes, including in its two most recent general rate cases, the Otter Tail 2010 Rate Case,[1] and the Otter Tail 2007 Rate Case.[2] *Id.* Otter Tail also used a different sales forecast method than it employed in the Otter Tail 2010

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[1] *In the Matter of the Application by Otter Tail Power Co. for Auth. to Increase Rates for Electric Serv. in Minn.*, Docket No. E-017/GR-10-239 (the *OTP 2010 Rate Case*).

[2] *In the Matter of the Application by Otter Tail Power Co. for Auth. to Increase Rates for Electric Serv. in Minn.*, Docket No. E-017/GR-07-1178 (the *OTP 2007 Rate Case*).

Rate Case. While both analyses used ordinary least squares (OLS), the analyses are noticeably different.

6. Otter Tail used OLS regression analysis for each of its rate classes as the basis for forecasting test-year customer counts. Ex. 1 Attach. A2-A8 (Pre-Filed Forecasting Data). These models used historical data (e.g., monthly factors, yearly factors, demographic data) over the period from July 1995 to August 2015 to forecast test-year customer counts. Heinen Direct, at 35.

7. Otter Tail used an acceptable method of calculating normal weather. The Department examined the raw weather input data, and was able to replicate Otter Tail's normal weather calculations.

8. The Department examined the validity of the raw data that Otter Tail used in its sales analyses[3] and had concerns with the relationship between Otter Tail's raw billing cycle data and the billing month data used as an input into the regression models. Otter Tail used a novel approach that was unlike the approach taken by all other utilities in Minnesota, which use raw billing cycle data for their billing month data. To the extent that Otter Tail's adjustments to raw data are consistent, the Department did not conclude in its Direct Testimony that Otter Tail's approach was unreasonable; however, given time constraints in the proceeding, it was unable to fully reconcile these data. Otter Tail offered to further explain its collection of data prior to the next rate case, which Department Witness Mr. Heinen indicated was likely an acceptable approach going-forward. Heinen Direct, at 37-38.

9. In general, the Department did not take issue with the Company's general forecasting approach, but had concerns regarding Otter Tail's construction of certain input data and its regression model specification and results, and for that reason, conducted an alternative test-year sales analysis. Heinen Direct, at 38-39.

C. Concerns with Otter Tail's Input Data and Regression Analysis

10. Otter Tail's data collection was similar to the approach in previous rate cases, but unlike the past two rate cases, Otter Tail forecasted sales instead of weather normalizing historical sales. *Id.* at 34-35. The Department observed several areas of concern in the Company's analysis and data construction. There were inaccuracies in the Company's raw weather data, unexpected changes in historical data when updated data were requested, and concerns regarding Otter Tail's construction of its weather data. There were also issues with the Company's model specifications; in particular, its use of yearly regression factors, a potential downward bias in its use per customer estimates, and a failure to account for serial correlation which resulted in inefficient regression estimates. The Department ultimately concluded that the Company's estimates are not reasonable for ratemaking purposes and conducted an alternative test-year sales forecast. *Id.* at 65-66. Two areas of concerns with the Company's data collection and forecasting analysis were: (1) certain input data into the models and (2) the specifications and testing of its models. *Id.* at 39; Heinen Surrebuttal, at 29.

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[3] The Department found no significant issues with Otter Tail's raw regression data. The regression data used in the analysis was CIS/A data, which matched what the Company filed in its most recent resource plan.

1. Concerns with Otter Tail's Input Data

11. There were inaccuracies in historical weather data and unexpected changes to historical use per customer data. Also, Otter Tail constructed a "virtual weather station" and based its weather weights on total actual sales, not weather sensitive sales, and only for a single year. Heinen Direct, at 39-43; Heinen Surrebuttal, at 29.[4] There were three issues with the Company's input data, two related to the Company's specification of weather data and one related to the use-per-customer data included in its regression models. Heinen Direct, at 39.

a. Otter Tail Used Incorrect Hourly Data

12. In Otter Tail's data, there were instances where zero degrees Fahrenheit was listed where there should have been temperatures logged (e.g., 75 degrees Fahrenheit). Ex. 1 Attach. A45 (Pre-Filed Forecasting Data). In its Response to DOC IR 516, the Company confirmed these issues with its input data and provided what it said was corrected weather data. Heinen Direct, at 39-40, AJH-11. Otter Tail, however, incorrectly calculated updated weather data for its Fergus Fall weather station.[5] The Department concluded that the Company's weather data was not reasonable. *Id.* at 40.

b. Otter Tail's Weather Weights

13. A second issue was related to the weather weights Otter Tail used to create its representative weather station. Otter Tail has a large geographic area, so the use of a single weather station may result in weather inputs that are not appropriate for estimating sales. Otter Tail created its representative weather station based on weather data, weighted by sales related to a geographic area, from various weather stations in the Company's service territory.[6] The Department was concerned about the reasonableness of the choice of sales data Otter Tail used to allocate weights between the various weather stations. Heinen Direct, at 40-41.

14. There were two concerns regarding the sales data: the length of time used to create the sales data, and the type of weather data used to create the weather weights. *Id.* at 41. Otter Tail should have used only weather-sensitive sales data in its creation of weather weights; this approach would have ensured that the weather data was more closely aligned with the objectives of a test year. *Id.* at 41-43, AJH-12.

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[4] The Department made corrections to address these concerns and incorporated these updated data into its alternative test-year sales forecast. Heinen Surrebuttal, at 29.

[5] Because use of the Company's weather data was not reasonable, the Department corrected this error, and then calculated normal weather data that appeared to be more accurate for the Otter Tail system, and used these corrected data in its alternative analysis. Heinen Direct, at 40.

[6] This approach was also employed by Minnesota Energy Resources Corporation in its estimation of test-year sales in Docket No. G-011/GR-13-167, *In the Matter of a Petition of Minnesota Energy Resources Corp. for Authority to Increase Natural Gas Rates in Minnesota*.

c. Otter Tail's Use-Per-Customer Input Data

15. Otter Tail's use-per-customer information from January 2015 onwards was not the same as initially filed by the Company. Ex. 1 Attachs. A23-A29 (Pre-Filed Forecasting Data). That these historical data changed when Otter Tail provided updated data through June 2016, raised concerns regarding the potential stability of Otter Tail's input data. Heinen Direct, at 43; Heinen Surrebuttal, at 39 – 47.

d. Otter Tail's Response to Concerns with Its Input Data

16. In its Rebuttal, the Company recommended using its initially filed forecast to set rates in this proceeding.

17. The Department disagreed. Because Otter Tail decided to update certain costs in its Rebuttal Testimony, it was also necessary to fully update the sales forecast. Heinen Surrebuttal, at 32. Otter Tail's recommendation to update costs while maintaining the initially filed test-year sales forecast is not reasonable. Otter Tail's updated test-year sales were not reasonable because they were not based on updated data. Heinen Surrebuttal, at 32.

2. Concerns Regarding Otter Tail's Model Specifications and Testing

18. Several issues existed with Otter Tail's regression model specifications. Otter Tail used yearly factors in its regression models and which is a violation of Ordinary Least Square (OLS) regression theory. Heinen Direct, at 44-53; Heinen Surrebuttal, at 29.

a. Yearly Factors and Joint Significance

19. In some of its use-per-customer models, Otter Tail included various yearly factors (e.g., 1998 factor, 2003 factor), which are meant to account for the influences of various years on the model results. The Company's application of these factors was problematic. Otter Tail did not include each individual yearly factor in its models; it included only the factors that were individually significant, which was not reasonable. Heinen Direct, at 44. The Department observed that Otter Tail had incorrectly specified certain factors in regression analysis, by failing consider their related nature. In particular, Otter Tail did not test for joint significance of yearly factors.

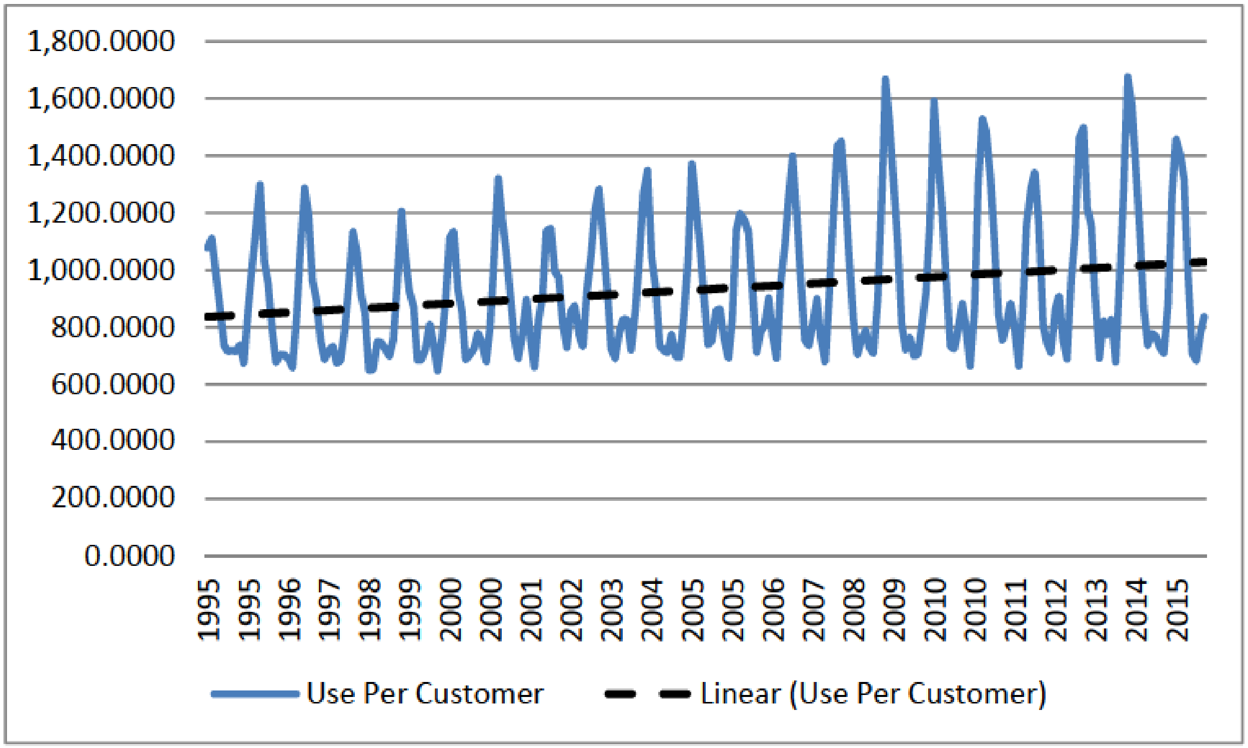
20. Otter Tail's Rebuttal responded regarding the Company's specification of yearly binary factors. Otter Tail's explanation was not compelling in light of known changes in energy efficiency. Since the enactment of the Next Generation Energy Act, conservation savings have generally increased in Minnesota, including in Otter Tail service territory. In light of this effect and the Company's explanation, one would expect yearly factors in recent times (e.g., the last five years) to be significant; however, for the Residential rate class, the year 2005 was the last significant yearly factor. Ex. 1 at Attach. A23 (Pre-Filed Forecasting Data). Heinen Surrebuttal, at 35.

21. Otter Tail's argument regarding downward trends in consumption in the past three years would imply that these recent yearly factors were significant, but, in fact, they were not. Heinen Surrebuttal, at 35 (citing Ex. 27 at 11 (Draxten Rebuttal)). Otter Tail's response is not compelling; the inclusion of yearly binary factors remained a modeling concern that Otter Tail should have addressed. Because the Company failed to address the concern, the Company failed to demonstrate that its modelling is reasonable. Heinen Surrebuttal, at 35.

b. Trend Factors

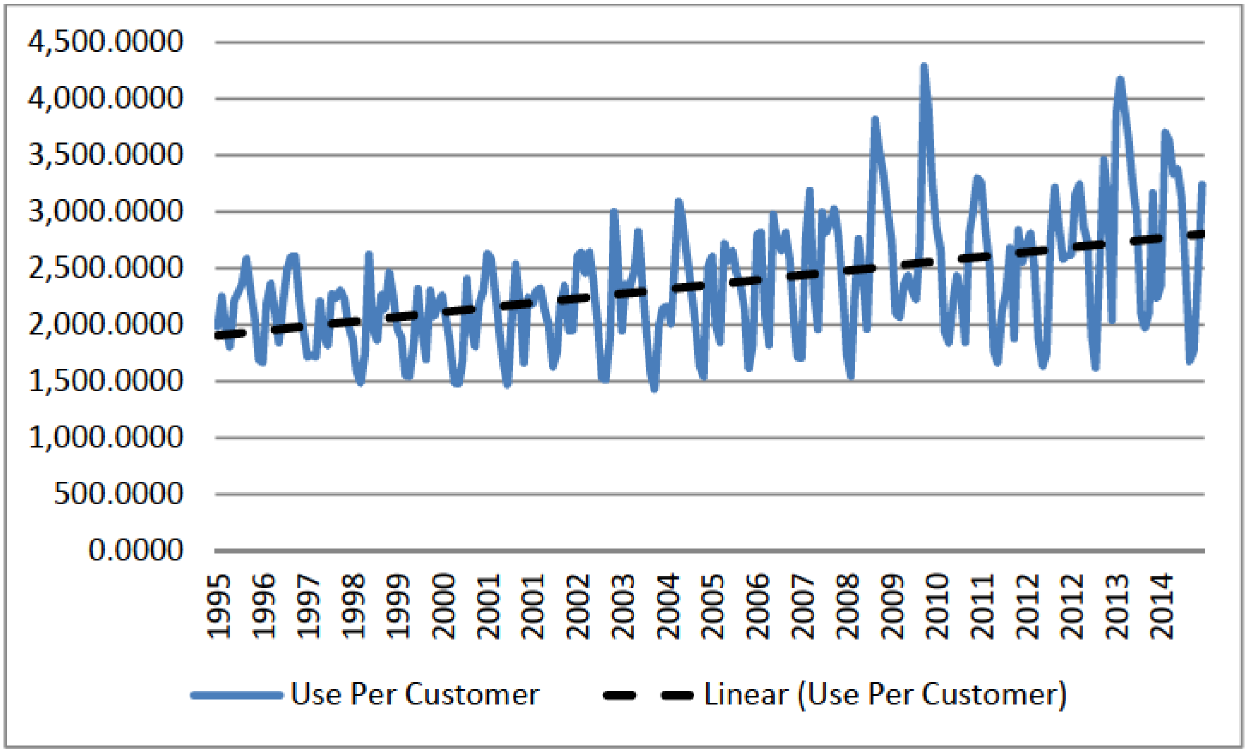
22. It was unclear from its Direct whether Otter Tail considered the inclusion of a trend factor in its analysis. The Company provided no discussion or support on this topic. Heinen Direct, at 46. The Company's data, however, suggested the presence of a trend in Otter Tail's historical use-per-customer data. The Department graphed the historical use-per-customer data for each of Otter Tail's rate classes and overlaid a trend function form Microsoft Excel on the underlying data. These graphs are shown separately below:

Heinen Direct Graph 1: Residential Use Per Customer



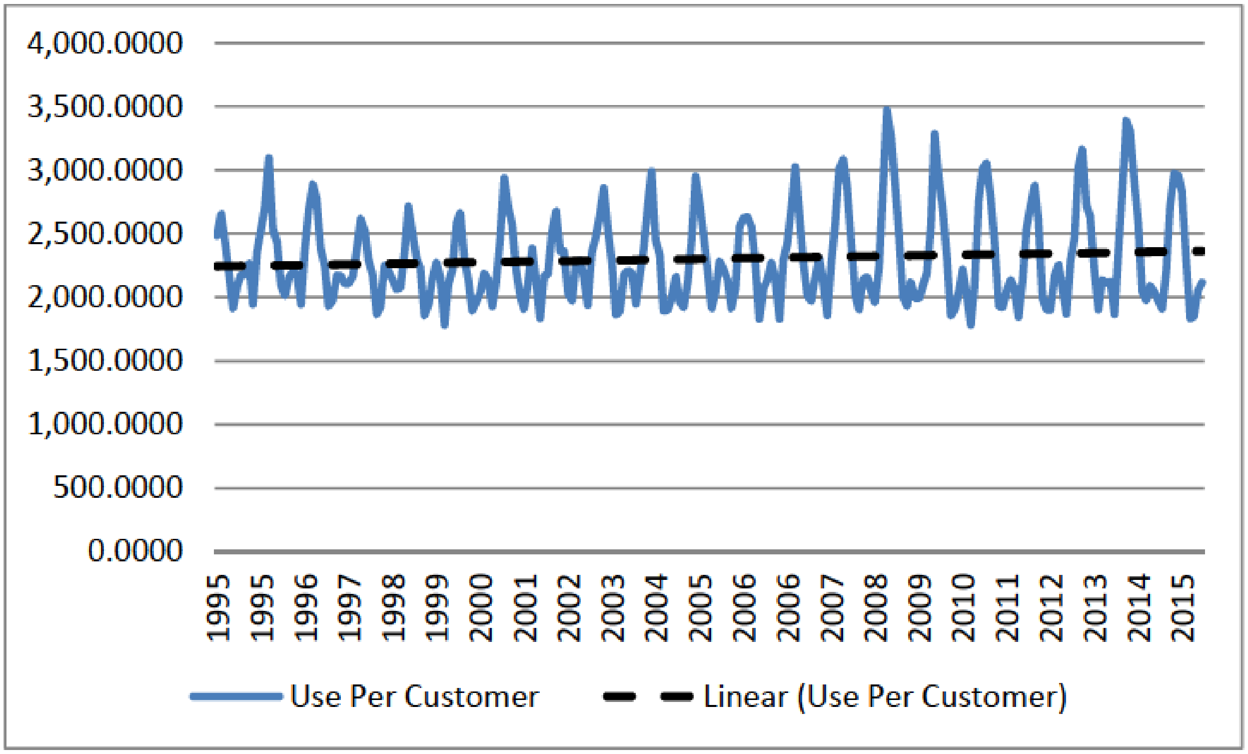
Heinen Direct, at 47.

Heinen Direct Graph 2: Farm Use Per Customer



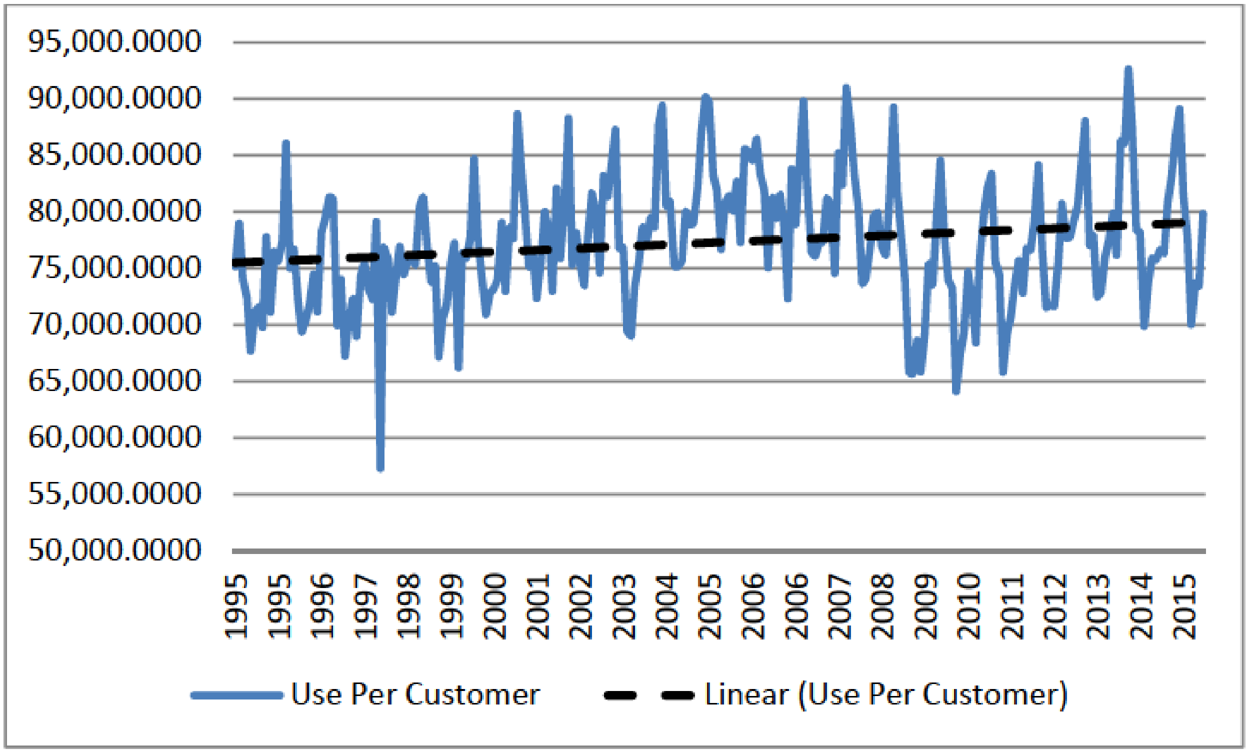
Heinen Direct, at 47.

Heinen Direct Graph 3: Small Commercial Use Per Customer



Heinen Direct, at 48.

Heinen Direct Graph 4: Large General Service Use Per Customer



Heinen Direct, at 48.

23. These graphs show a general trend upward in use per customer, for each of Otter Tail's rate classes, with some trends more marked than others. Even if the trend factor is not significant, it may still be appropriate to include a proxy, or related factor, in the regression model. The most straightforward way to test this would be to include a trend factor in each of the Company's originally-filed regression models. Heinen Direct, at 48-49. The Department did so, and included a simple trend factor in each of the Company's initial filed model specifications and the results show that a simple trend is statistically significant for all of the rate classes. The results are listed in Heinen Direct, at AJH-16. *Id.* at 49.

24. The Department was concerned that there were issues with the Company's model results. Otter Tail's originally filed forecast used data from the period of September 2015 to December 2016. As shown in Heinen Direct Table 11 below, the outcome of the regression models is the same in 2015 and 2016 for September through December; in other words, Otter Tail forecasts zero growth in its sales forecast, which contrast to the significant trends for some of its customer classes. *Id.*

Month	Residential	Farm	Small Commercial	Large Commercial
9/2015	791	2,428	2,053	77,999
10/2015	732	2,121	1,892	75,029
10/2015	903	2,846	2,223	80,004
10/2015	1,135	2,784	2,578	80,436
01/2016	1,467	3,009	3,032	84,623
02/2016	1,436	2,977	3,040	85,586
03/2016	1,258	2,675	2,704	78,247
04/2016	998	2,367	2,404	77,100
05/2015	799	1,877	1,937	71,726
06/2016	746	1,832	1,902	73,061
07/2016	813	2,368	2,079	74,968
08/2016	852	2,864	2,139	76,886
09/2016	791	2,435	2,053	77,999
10/2016	732	2,128	1,892	75,029
11/2016	903	2,852	2,223	80,004
12/2016	1,135	2,791	2,578	80,436

Heinen Direct, at 50.

25. Because the Company's forecasts showed the same level of use per customer (except for the Farm rate class), and there was evidence of increasing use per customer as shown in Graphs 1 through 4 above, the results in Heinen Direct Table 11 suggested that Otter Tail built a downward bias into its use per-customer-forecasts. Specifically, the Company failed fully to account for increasing use per customer for three of its four rate classes whose use if graphed above. Heinen Direct, at 50.

26. For the fourth rate class, the Farm Class, Otter Tail's model exhibited increasing use per customer because Otter Tail did include a Farm Earnings factor in the regression model for this rate class. The data for this factor in the forecast period grows at a steady linear pace and, in the historical period, farm earnings exhibited growth over the sample period. *Id.* Otter Tail should have specified various factors, similar to Farm Earnings, in its other rate class models. The historical data shows that, in general, use per customer increased over the past 20 years. OYP's forecast of flat growth in the last half of the test year for its Residential, General Service, and Large General Service rate class was unexpected and did not match historical use-per-customer patterns. The lack of growth in 2016 relative to 2015 suggested a downward bias in test-year sales. Because a lower forecast disadvantages Otter Tail's ratepayers by overstating the revenue deficiency, the presence of this downward bias in Otter Tail's test-year sales called into question the reasonableness of using the Company's sales forecast to set rates. *Id.* at 51.

27. In Rebuttal, Otter Tail responded to the Department's concern with the Company's decision not to include a trend factor in its regression models to account for historical growth. Otter Tail said the Department's concern was misplaced because "Structural changes" are occurring in how energy is used at the class level. The Company said that the 20 year-long historical upward trend in consumption (shown in Heinen Direct Graphs 1 through 4) should not be relied on because there had been negative growth in sales during the recent period of 2013-2015. Heinen Surrebuttal, at 36 (citing Ex. 27 at 11(Draxten Rebuttal)).

28. That customer usage has decreased during the recent three year period is not a compelling reason to find Otter Tail's sales forecast reasonable, for several reasons.

29. First, usage ordinarily may go up or down and may decrease on a (short) year-to-year basis. Heinen Surrebuttal, at 36. The selection of end points of a study may not reflect longer term trends that should be accounted for in a forecast.

30. Second, as noted above, the Next Generation Energy Act has helped reduce energy use, but it is premature to conclude based on only three years of data that consumption is now trending downward, when the previous 20 years of data suggests the presence of a noticeable upward consumption trend. *Id.*

31. Third, the last three years of data is, in fact, anomalous, given the characteristics of the Otter Tail system and recent unusual weather. That is, Otter Tail is a winter peaking electric utility and experiences higher usage in the winter, similar to a natural gas utility. Otter Tail selected consumption data over the period from 2013-2015, which included one of the coldest winters in recent memory (i.e., 2013-2014) and also one of the warmer winters in recent memory (i.e., the first part of the 2015-2016 heating season). By selecting these dates, one would expect a significant reduction in sales between calendar year 2014 and 2015, because 2014 would be set at an unusually high level of consumption and 2015 would be set at an unusually low level of consumption. See Ex. 27 at BHD-2 (Draxten Rebuttal). The Company's use of a two-year average is insufficient to determine an adequate or reasonable calculation of a trend. Heinen Surrebuttal, at 36-37.

c. Model Testing

32. From the information in Otter Tail's initially-filed regression models, it was unclear whether the Company accounted for serial correlation in its regression results. Heinen Direct, at 51 (citing Ex. 1 Attachs. A23-A29 (Pre-Filed Forecasting Data). The potential presence of serial correlation a significant issue in a regression model because it violates the OLS regression theory. If serial correlation exists, the model results are not efficient and may appear better, or more precise, than they really are. In addition, serial correlation may lead the analyst to include erroneous factors or remove relevant factors from the regression analysis, which will in turn impact the subsequent model results. If the results are inefficient, then the results of the model, and any subsequent forecast, may raise concerns about their reasonableness for ratemaking. Heinen Direct, at 51-52.

33. Otter Tail tested for serial correlation in its models and was unable to show that Otter Tail's models do not have serial correlation, which meant that the Company was unable to confirm whether its model results were efficient or correctly specified. *Id.* at 52.

34. Because of this problem, the Department conducted an alternative test to determine whether the Company's models are free of serial correlation and found the presence of serial correlation in each of the Company's originally filed use-per-customer models. *Id.* at AJH-17. These results demonstrate that Otter Tail's regression model results, and subsequent forecasts, are flawed, and likely not appropriate for ratemaking purposes. *Id.* at 52-53.

35. In Rebuttal, Otter Tail responded to these concerns regarding the presence of serial correlation in its regression models. Heinen Direct, at 51-53. Otter Tail attempted to minimize these concerns by arguing that it included the correct factors in its analysis. Otter Tail stated that it re-ran its models correcting for serial correlation which resulted in a lower estimate of use per customer. Ex. 27 at 12 (Draxten Rebuttal); Heinen Surrebuttal, at 37.

36. Because Otter Tail's filed models, which included the presence of serial correlation, resulted in a higher estimate of test-year use per customer, there is no risk to ratepayers at this time, but the Company's response in Rebuttal was not accurate and attempted to minimize serial correlation. If a model has serial correlation, the model violates the assumptions of OLS regression, which is a concern that should have been addressed. Heinen Direct, at 51-52. Even if the Company has specified, or used, the "best or most appropriate factors," serial correlation can still exist and should have been accounted for to ensure the most robust estimates and corresponding forecasts. Heinen Surrebuttal, at 37-38.

37. The Commission finds that the Company's regression models are not reasonable.

D. The Department's Alternative Test-Year Sales Forecast Should Be Used

38. Based on these concerns with the Company's data and regression models, the Department conducted an alternative test-year sales analysis in its Direct Testimony. This alternative analysis accounted for the issues observed with the Company's analysis and also used updated data through June, 2016, which required the Department to undertake a hybrid test-year analysis, using weather-normalized sales between January and June, 2016 and forecast sales between July, 2016 and December, 2016. The Department used similar models for each of the Company's rate classes, which incorporated weather, monthly factors, and autoregressive terms to estimate use per customer. Heinen Direct, at 53-61; Heinen Surrebuttal, at 30.

39. The alternative test-year sales forecast was based on OLS regression techniques and employed the same basic factors for each of the rate class regression models. These regression models estimate use per customer and arrived at test-year sales by multiplying the Company customer count figures by the Department's use per customer estimates. The alternative analysis resulted in an overall increase in test-year sales and revenues. Heinen Direct, at 66-67.

40. The Department's alternative analysis calculated weather and normal weather in the same manner that Otter Tail did, and the only difference was that the data were updated to the most recent 20-year period available and other minor adjustments such as weather station allocators. *Id.* at 54.

41. To estimate test-year use per customer with updated data through June, 2016, the Department used a hybrid estimation process. When forecasting the results for the six-month period at the end of the test year, the Department substituted normal calendar month weather data in place of billing month data in the forecasting period to arrive at normal calendar month data. Id. at 55. For the first six months of 2016 the Department used actual, historical data with a weather normalization adjustment, similar to the one Otter Tail used to normalize weather and calendarize data in its last rate case. Heinen Direct, at 56; Heinen Surrebuttal, at 38-39.

42. A detailed breakdown of the Department's monthly regression and forecasting results, by rate class, were provided in Direct Testimony in *Id.* at AJH-21.

43. The total test-year sales forecast results, by rate class, and their comparison to Otter Tail's originally filed estimates, were provided by Department witness Mr. Heinen. *See* Heinen Direct (Trade Secret), at 58 and AJH-21.

44. In its Direct Testimony, in its calculation of test-year revenue, the Department did not make adjustments to test-year customer counts, but reviewed the Company's test-year customer counts and determined that even with updated data, Otter Tail's originally filed customer counts were acceptable for ratemaking purposes. Heinen Direct, at 59.

E. The Department's Updated Alternative Test-Year Sales and Revenue Forecast

45. Subsequent to Rebuttal Testimony, Otter Tail estimated the relationship between its updated customer counts and updates to meter counts associated with these new customer counts.

46. Using this information, the Department updated its analysis in its Surrebuttal, and modified its initial test-year sales forecast to include the updated customer counts provided by Otter Tail in its Rebuttal Testimony (Heinen Surrebuttal, at 41-42 (citing Draxten Rebuttal, Sch.1)) and provided updated individual rate class test-year sales results.

47. The Department summarized its updated total test-year sales forecast results, by rate class, and their comparison to Otter Tail's originally filed estimates in Table S-5, and in Heinen Surrebuttal (Trade Secret), at AJH-S-6.

Heinen Table S-5: Updated DOC Rate Class Sales Figures and Adjustments

Rate Class	Dept Sales (kWh)	Otter Tail Sales (kWh)	Difference (kWh) Dept. – OTP*
Residential	572,171,258	578,103,106	(5,931,848)
Farm	43,471,612	40,915,533	2,556,079
General Service	278,247,560	271,629,716	6,617,844
Large Gen Service	Trade Secret Data	Trade Secret Data	
Pipelines	Trade Secret Data	Trade Secret Data	
Lighting	10,579,232	10,579,232	0
OPA	18,900,350	20,621,001	(1,720,651)
Total	2,640,367,131	2,641,640,337	(1,273,206)

> * A positive number indicates that the DOC's sales estimate is higher than Otter Tail's estimate, while a negative number indicates that Otter Tail's sales estimate is higher than the DOC's estimate.
>
> Note: The Large General Service sales data are labeled trade secret to protect the sensitive nature of the Pipeline rate class.
>
> Heinen Surrebuttal, at 43.

48. Because test-year revenue is based, in large part, on sales during the test year, it is necessary to adjust test-year revenues when there are changes in projected sales. In Surrebuttal, because the Department recommended the above changes in test-year sales, the Department also recommended an adjustment to Otter Tail's test-year revenue. *Id.* at 43.

49. The Department calculated test-year revenue using the same method it had used in Direct Testimony: *Id.*[7] The Department's final recommendation resulted in an increase in test-year revenue of $293,272 and a decrease in test-year energy expenses of $31,372, which yielded a net increase to test-year revenue of $324,644. Heinen Surrebuttal, at 46; Ex. 518 at 1 (Heinen Summary). The updated revenue adjustments the Department recommended are in Table S-6:

Heinen Table S-6: Updated DOC Rate Class Revenue Figures and Adjustments

Rate Class	DOC Revenue	Otter Tail Revenue	Difference DOC – Otter Tail
Residential	$42,632,292	$42,735,029	($102,737)
Farm	$2,921,507	$2,741,585	$179,922
General Service	$28,163,826	$27,521,622	$642,204
Large Gen Service	$86,526,003	$86,466,549	$59,454
Irrigation	$391,278	$367,579	$23,699
Lighting	$2,628,515	$2,572,935	$55,580
OPA	$1,255,808	$1,367,821	($112,013)
Water Heating	$1,529,279	$1,490,051	$39,228
Control Service Interruptible	$6,049,455	$6,451,328	($401,873)
Control Service Def.	$1,363,670	$1,453,862	($90,192)
Total	$173,461,633	$173,168,361	$293,272

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[7] In addition, prior to the evidentiary hearing, Otter Tail contacted the Department and identified a calculation error in the Department's calculation of test-year revenue that resulted in an underestimation of test-year revenue. Heinen filed corrected versions in which the test-year revenues were adjusted to account for this error. *See* Heinen's corrected Surrebuttal, Ex. 512 and 513.

> * A positive number indicates that the DOC's revenue estimate is higher than Otter Tail's estimate, while a negative number indicates that Otter Tail's revenue estimate is higher than the DOC's estimate.
>
> Note: The Large General Service sales data are labeled trade secret to protect the sensitive nature of the Pipeline rate class.

Heinen Surrebuttal, at 44

50. As detailed in Heinen Table S-6, the Department in its Surrebuttal Testimony recommended a total base test-year revenue figure of approximately $173,461,633.[8] This amount represents an increase in base test-year revenue of approximately $293,272 over Otter Tail's originally-filed proposed revenue figure of $173,168,361. Heinen Surrebuttal, at 44-45; Heinen Surrebuttal (Trade Secret), at AJH-S-7.[9]

51. The base cost of energy, when applied to the Department's updated alternative test-year sales estimates decreased test-year energy expenses by approximately $31,372. Heinen Surrebuttal, at 45, AJH-S-6. Because this amount was a decrease in test-year expenses, it increased the net effect of the Department's $293,272 revenue adjustment.[10] When the decrease in energy expenses is considered alongside the increase in test-year revenue, the Department in Surrebuttal recommended a net increase to test-year revenue of approximately $324,644.[11] *Id.* at 45.

F. Test-Year Sales and Revenue Findings, Summary and Conclusions

52. The Commission finds that Otter Tail's test-year sales analysis and subsequent forecasting results were not reasonable.[12] There were issues regarding the Company's input data, and with Otter Tail's model specification and testing. There were issues with Otter Tail's input data, including historical hourly weather data, the Company's construction and specification of its weather weights, and a change in historical data when updated data were provided in discovery. Heinen Direct, at 61.

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[8] The Department's test-year revenue figure does not include other revenues such as those collected through riders.

[9] This updated result is closer to OTP's proposal than the amount in the Department's Direct Testimony, which represented an increase in test-year revenue of $1,983,158. Heinen Direct, at 60.

[10] This is calculated in Heinen Surrebuttal, at AJH-S-7.

[11] For comparison, the amount in Direct Testimony was $1,396,206. Heinen Direct, at 61.

[12] OTP proposed total system test-year sales of approximately 2,641,640,337 kWh. Ex. 1, Attach. A51 (Pre-Filed Forecasting Data). OTP proposed total test-year revenue of approximately $222,092,895. Ex. 1 Attach. B11 (Pre-Filed Forecasting Data); Heinen Direct, at 62.

53. The Commission finds that regarding the model construction and specification, there are issues regarding Otter Tail's inclusion of yearly factors in various model specifications, the Company's failure to account for increasing use per customer in several of its regression models, and the presence of, and failure to correct for, serial correlation in its regression models. *Id.* at 61-62.

54. The Commission finds that adjustments to Otter Tail's test-year sales and revenues are needed because these problems in Otter Tail's forecasting analysis are significant and render Otter Tail's test year sales and revenues unreasonable for ratemaking purposes.

55. The Commission finds that the Department's Surrebuttal alternative test-year sales and revenue analysis and figures should be used in this rate case.

56. The Commission adopts the Department's alternative analysis in its corrected Surrebuttal, which results in test-year sales of 2,640,367,131 kWh, which is 1,273,206 kWh lower than the Company's originally filed estimate of 2,641,640,337 kWh. *Id.* at 47, AJH-S-6. When the applicable tariff rates are applied to the Department's test-year sales estimates, it results in base test-year revenues of $173,461,633. This figure is $293,272 greater than Otter Tail's filed base test-year revenue figure of $173,168,361. *Id.* at 47. The recommended decrease in test-year sales results in a decrease of $31,372 in test-year energy expense. *Id.* at 47, AJH-S-6. When the decrease in energy expenses is accounted for, along with the increase in test-year revenue, this results in a net increase to test-year revenue of approximately $324,644 over Otter Tail's proposed test-year revenue. *Id.* at 47-48.

57. The Commission will direct Otter Tail to do the following for its next rate case:

- In its Pre-Filed forecasting data in its next rate case, Otter Tail should provide an analysis, and fully linked spreadsheets, which ties the Company's test-year customer counts and test-year meter counts together. Heinen Surrebuttal, at 46.

- Prior to the initial filing and completion of future rate case forecasts, Otter Tail should correct the data from its data collection and billing system in the same manner that it does at the end of each calendar year. If Otter Tail uses actual data in the base year as it did in this case (i.e., through August 2015), then Otter Tail should insure that, to the fullest extent possible, all billing or other errors are corrected before the Company's files its general rate case. Moreover, such corrections should be made to the month(s) in which the error occurred rather than the month when the error was discovered. Heinen Surrebuttal, at 40, 46-47.

FEDERAL RESERVE press release

BOARD OF GOVERNORS OF THE FEDERAL RESERVE SYSTEM

For release at 2:00 p.m. EDT March 20, 2024

Recent indicators suggest that economic activity has been expanding at a solid pace. Job gains have remained strong, and the unemployment rate has remained low. Inflation has eased over the past year but remains elevated.

The Committee seeks to achieve maximum employment and inflation at the rate of 2 percent over the longer run. The Committee judges that the risks to achieving its employment and inflation goals are moving into better balance. The economic outlook is uncertain, and the Committee remains highly attentive to inflation risks.

In support of its goals, the Committee decided to maintain the target range for the federal funds rate at 5-1/4 to 5-1/2 percent. In considering any adjustments to the target range for the federal funds rate, the Committee will carefully assess incoming data, the evolving outlook, and the balance of risks. The Committee does not expect it will be appropriate to reduce the target range until it has gained greater confidence that inflation is moving sustainably toward 2 percent. In addition, the Committee will continue reducing its holdings of Treasury securities and agency debt and agency mortgage-backed securities, as described in its previously announced plans. The Committee is strongly committed to returning inflation to its 2 percent objective.

In assessing the appropriate stance of monetary policy, the Committee will continue to monitor the implications of incoming information for the economic outlook. The Committee would be prepared to adjust the stance of monetary policy as appropriate if risks emerge that could impede the attainment of the Committee’s goals. The Committee’s assessments will take

(more)

into account a wide range of information, including readings on labor market conditions, inflation pressures and inflation expectations, and financial and international developments.

Voting for the monetary policy action were Jerome H. Powell, Chair; John C. Williams, Vice Chair; Thomas I. Barkin; Michael S. Barr; Raphael W. Bostic; Michelle W. Bowman; Lisa D. Cook; Mary C. Daly; Philip N. Jefferson; Adriana D. Kugler; Loretta J. Mester; and Christopher J. Waller.

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Attachment

For media inquiries, please email media@frb.gov or call 202-452-2955.

For release at 2:00 p.m. EDT   March 20, 2024

Decisions Regarding Monetary Policy Implementation

The Federal Reserve has made the following decisions to implement the monetary policy stance announced by the Federal Open Market Committee in its statement on March 20, 2024:

- The Board of Governors of the Federal Reserve System voted unanimously to maintain the interest rate paid on reserve balances at 5.4 percent, effective March 21, 2024.
- As part of its policy decision, the Federal Open Market Committee voted to direct the Open Market Desk at the Federal Reserve Bank of New York, until instructed otherwise, to execute transactions in the System Open Market Account in accordance with the following domestic policy directive:

  "Effective March 21, 2024, the Federal Open Market Committee directs the Desk to:
    - Undertake open market operations as necessary to maintain the federal funds rate in a target range of 5-1/4 to 5-1/2 percent.
    - Conduct standing overnight repurchase agreement operations with a minimum bid rate of 5.5 percent and with an aggregate operation limit of $500 billion.
    - Conduct standing overnight reverse repurchase agreement operations at an offering rate of 5.3 percent and with a per-counterparty limit of $160 billion per day.
    - Roll over at auction the amount of principal payments from the Federal Reserve's holdings of Treasury securities maturing in each calendar month that exceeds a cap of $60 billion per month. Redeem Treasury coupon securities up to this monthly cap and Treasury bills to the extent that coupon principal payments are less than the monthly cap.
    - Reinvest into agency mortgage-backed securities (MBS) the amount of principal payments from the Federal Reserve's holdings of agency debt and agency MBS received in each calendar month that exceeds a cap of $35 billion per month.
    - Allow modest deviations from stated amounts for reinvestments, if needed for operational reasons.
    - Engage in dollar roll and coupon swap transactions as necessary to facilitate settlement of the Federal Reserve's agency MBS transactions."

- In a related action, the Board of Governors of the Federal Reserve System voted unanimously to approve the establishment of the primary credit rate at the existing level of 5.5 percent.

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This information will be updated as appropriate to reflect decisions of the Federal Open Market Committee or the Board of Governors regarding details of the Federal Reserve's operational tools and approach used to implement monetary policy.

More information regarding open market operations and reinvestments may be found on the Federal Reserve Bank of New York's website.

MOODY'S
INVESTORS SERVICE

Rating Action: Moody's downgrades Pinnacle West to Baa1 and Arizona Public Service to A3; outlook negative

17 Nov 2021

Approximately $6.5 billion of debt securities downgraded

New York, November 17, 2021 -- Moody's Investors Service ("Moody's") downgraded the long-term ratings of Pinnacle West Capital Corporation (Pinnacle) including its senior unsecured and Issuer ratings to Baa1 from A3. Pinnacle's short-term rating for commercial paper was affirmed at Prime-2. Concurrently, Moody's downgraded the ratings of utility subsidiary Arizona Public Service Company (APS) including its senior unsecured and Issuer ratings to A3 from A2 and its short-term rating for commercial paper to Prime-2 from Prime-1. The outlooks for both companies are negative. This concludes the review for downgrade initiated on 12 October 2021.

A complete list of rating actions appears below.

RATINGS RATIONALE

"The downgrades of Pinnacle and APS are prompted by the recent decline in Arizona regulatory environment following the conclusion of the utility's 2019 rate case as well as the organization's weakened credit metrics" stated Edna Marinelarena, Assistant Vice President. The rate case proceedings were highly contentious, and the final outcome will result in both companies sustaining credit metrics well below historical levels. We expect APS's cash flow from operations before changes in working capital (CFO pre-WC) to debt ratio to range between 19% and 20% over the next several years while Pinnacle's CFO pre-WC to debt ratio is projected to be between 17% and 19% over the same period. This compares to CFO pre-WC to debt ratios that had historically been comfortably above 20% at both the utility and the parent company.

The rate case decision will result in a base rate decrease of $119.8 million and a substantive decline in the authorized ROE to 8.7% from 10%, which is well below the national average of 9.5%. Additionally, the Arizona Corporation Commission (ACC) voted to disallow $215.5 million of the utility's selective catalytic reduction (SCR) investments made at the Four Corners plant in 2018 and also disallowed a grid access fee charge. These results are indicative of a less credit supportive and predictable regulatory framework in Arizona compared to the rest of the country, materially increasing regulatory risk for both Pinnacle and APS going forward. Partially offsetting these adverse developments is an equity layer that remains among the highest in the nation at 54.7%.

Since 2018, both APS and Pinnacle's financial metrics had already been declining primarily because of the effect of 2017 tax reform and regulatory lag largely related to the deferrals of the Four Corners SCR and Ocotillo plant upgrades. The CFO pre-WC to debt ratios have dropped significantly from the mid 20% range to a weak 17% for APS and 16% for Pinnacle at the end of 2020. We see the ratio remaining below 20% for both companies through 2021 as debt funded capital investments outpace cash flow. We expect credit metrics to marginally improve in 2022 as the company collects revenue associated with the Four Corners and Ocotillo plant investments that were authorized in the 2019 rate case; including the partial disallowance of the SCR, but they will not approach historical levels. We expect CFO pre-WC to debt to be about 20% for APS and 18% for Pinnacle in 2022.

APS plans to maintain its elevated capital spending amidst this period of higher regulatory risk. The company expects to invest about $1.5 billion annually, or a total of $4.7 billion, through 2024. Pinnacle plans to issue about $1 billion in debt to supporting capex at APS increasing its holding company debt to about 17% of consolidated debt from 7% at the end of 2020. We expect holding company debt to remain below 20% over the next several years. Although Arizona regulators have thus far not typically focused on the amount of debt issued at the holding company, given the recent negative regulatory developments, the higher debt levels at the holding company could fall under scrutiny.

Although we expect APS's and Pinnacle's credit metrics to improve slightly, the negative outlooks reflects the organization's limited financial flexibility to manage unforeseen events. Additionally, there is increased uncertainty over APS's ability to recover its 100% of its future capital investments in a timely manner following the conclusion of the 2019 rate case. APS is now operating in a regulatory environment that is prioritizing customer bill impact and affordability concerns to the detriment of credit supportive cost recovery for the utility, unlike most other regulatory frameworks where utilities and their regulators have been more balanced and achieved both goals. The utility's future rate case filings will likely receive higher scrutiny, potentially leading to an increase in regulatory lag and disallowances of other mechanisms which could further pressure credit ratings going forward.

We note that APS's regulatory relationship had already become increasingly challenged for a number of reasons prior to the recent rate case outcome, including the utility's poor implementation of new rate plans in 2018, controversial disconnection policies during times of excessive heat in 2019, its provision of a faulty rate comparison tool to customers and the level of campaign contributions made by Pinnacle. These issues stressed the company's relationship with the ACC and led regulators to open an investigation into APS's earnings, require the utility to file a new rate case in 2019, and customer outreach programs. These issues plagued the company during the rate case proceedings despite several of these matters having been resolved separately. APS filed the recently concluded rate case just over two years ago, on 31 October 2019, originally requesting a $184 million (5.4%) revenue increase and a 10.15% ROE, and ultimately falling well short of its initial request.

ESG Considerations

Pinnacle's ESG Credit Impact Score is CIS-3 (Moderately Negative), where its ESG attributes are overall considered as having a limited impact on the current rating, with greater potential for future negative impact over time. Pinnacle's CIS-3 reflects its highly negative exposure to social risk, moderately negative exposure to environmental risk and neutral to low exposure to governance risk.

Pinnacle's exposure to environmental risk is moderate (E-3 issuer profile score) and driven by its moderately negative physical climate and water management risks, because the state of Arizona, Pinnacle's primary service territory, is exposed to heat and water stress. These risks are offset by neutral to low exposure to waste and pollution and natural capital.

The organization's exposure to social risk is highly negative (S-4 issuer profile score) driven by demographics and societal trends that could increase public concern over environmental, social or affordability issues that could lead to adverse regulatory or political decisions. While the ACC has been constructive and credit supportive historically, it has been less consistent and predictable more recently. Furthermore, as the owner and operator of the nation's largest nuclear facility, the Palo Verde Nuclear Generation Station, Pinnacle's risk of responsible production is heightened. Pinnacle also faces high risks associated with customer relations and a neutral to low risk related to health and safety and human capital.

Governance is broadly in line with other utilities and does not pose a particular risk (G-2 issuer profile score). For Pinnacle, the board structure primarily stands out as moderately negative due to having a less independent board and committees, however it is balanced by other aspects of governance strength that are derived in part by management credibility and track record as well as financial policy and risk management.

Rating Outlook

The negative outlook reflects increased regulatory risk, uncertainty over future rate case filings, and the lack of financial flexibility as credit metrics have fallen. APS is operating in a more challenging regulatory jurisdiction, could experience higher scrutiny over future investments and may face disallowances of other cost recovery mechanisms given the ACC's focus on customer affordability.

FACTORS THAT COULD LEAD TO AN UPGRADE OR DOWNGRADE OF THE RATINGS

Factors that could lead to an upgrade

A rating upgrade is unlikely over the next 12 to 18 months because of the negative outlook on both APS and Pinnacle. Both companies' outlooks could return to stable if there is evidence of a more constructive and credit supportive regulatory framework in Arizona. Longer term, greater regulatory predictability combined with stronger financial metrics, such that the CFO pre-WC to debt ratio is above 24% for APS and 23% for Pinnacle, could result in upward rating movement.

Factors that could lead to a downgrade

Pinnacle and APS's ratings could be downgraded if the Arizona regulatory environment deteriorates further, such as through additional cost recovery disallowances, prolonged rate case proceedings or adverse regulatory outcomes. A rating downgrade could also occur if APS experiences prolonged operational difficulties, lower cash flow or higher unrecoverable costs that would lead to the CFO pre-WC to debt ratio to fall below 20%. For Pinnacle, a ratio below 18% or an increase in parent level debt above 25% of consolidated debt could result in a rating downgrade.

Headquartered in Phoenix, AZ, Pinnacle is a holding company whose principal operating subsidiary, APS, is a regulated, vertically integrated electric utility providing electric service to more than 1.2 million customers in 11 of the 15 counties in Arizona. APS currently represents essentially all of Pinnacle's consolidated assets and revenues.

Affirmations:

..Issuer: Pinnacle West Capital Corporation

....Senior Unsecured Commercial Paper, Affirmed P-2

Downgrades:

..Issuer: Pinnacle West Capital Corporation

.... Issuer Rating, Downgraded to Baa1 from A3

....Senior Unsecured Bank Credit Facility, Downgraded to Baa1 from A3

....Senior Unsecured Regular Bond/Debenture, Downgraded to Baa1 from A3

..Issuer: Arizona Public Service Company

.... Issuer Rating, Downgraded to A3 from A2

....Senior Unsecured Bank Credit Facility, Downgraded to A3 from A2

....Senior Unsecured Commercial Paper, Downgraded to P-2 from P-1

....Senior Unsecured Regular Bond/Debenture, Downgraded to A3 from A2

....Senior Unsecured Shelf, Downgraded to (P)A3 from (P)A2

..Issuer: Maricopa Co. Pollution Control Corp., AZ

....Senior Unsecured Revenue Bonds, Downgraded to A3 from A2

....Senior Unsecured Revenue Bonds, Downgraded to P-2 from P-1

Outlook Actions:

..Issuer: Arizona Public Service Company

....Outlook, Changed To Negative From Rating Under Review

..Issuer: Pinnacle West Capital Corporation

....Outlook, Changed To Negative From Rating Under Review

The principal methodology used in these ratings was Regulated Electric and Gas Utilities published in June 2017 and available at https://www.moodys.com/researchdocumentcontentpage.aspx?docid=PBC_1072530 . Alternatively, please see the Rating Methodologies page on www.moodys.com for a copy of this methodology.

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The Commonwealth of Massachusetts

DEPARTMENT OF PUBLIC UTILITIES

D.P.U. 22-22 November 30, 2022

Petition of NSTAR Electric Company, doing business as Eversource Energy, pursuant to G.L. c. 164, § 94 and 220 CMR 5.00, for Approval of a General Increase in Base Distribution Rates for Electric Service and a Performance Based Ratemaking Plan.

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TABLE OF CONTENTS

I. INTRODUCTION

On January 14, 2022, NSTAR Electric Company d/b/a Eversource Energy ("NSTAR Electric" or "Company") filed a petition with the Department of Public Utilities ("Department") for an increase in its electric base distribution rates to generate $89,477,862 in additional revenues. The Company also proposed to transfer costs recovered through certain reconciling mechanisms, which totaled $58,184,827 in calendar year 2020, to base distribution rates.[1] Based on this proposal, the Company's initial proposed overall increase to distribution revenues was $147,662,689, which represented a 13.2 percent increase in distribution revenue. Based on changes made during the proceeding,[2] NSTAR Electric now proposes a general increase in base distribution rates of $93,443,489, a transfer of $46,794,254 in revenues recovered through reconciling mechanisms, and an overall net increase of $140,237,743.[3]

NSTAR Electric also proposes to implement a performance-based ratemaking ("PBR") mechanism that would allow the Company to adjust its base distribution rates on an annual basis through the application of a revenue-cap formula (Exh. ES-CAH/DPH-1, at 13).

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[1] The Company's filing includes new tariffs designed to recover the proposed revenue increase (Exh. ES-RDC-6, Schs. 1 (clean), 2 (redlined)).

[2] In providing its updated revenue requirement schedules, the Company labeled them by date. For ease of reference, the Department refers to them by revision number. Thus, the April 24, 2022, update is Rev. 1; the June 24, 2022, update is Rev. 2; the August 5, 2022, update is Rev. 3; and the September 27, 2022, update is Rev. 4.

[3] Minor discrepancies in any of the amounts appearing in this Order are due to rounding.

NSTAR Electric proposes a ten-year PBR plan, and to implement a set of performance metrics to evaluate the Company's performance during the PBR plan's term (Exh. ES-CAH/DPH-1, at 8-11, 13, 15).[4]

NSTAR Electric bases its proposed base distribution rate increase on a calendar test year of January 1, 2020 through December 31, 2020 (Exh. ES-REVREQ-1, at 12). NSTAR Electric was last granted an increase in electric base distribution rates in 2017. NSTAR Electric Company and Western Massachusetts Electric Company, D.P.U. 17-05 (2017).[5] The Department docketed the instant petition as D.P.U. 22-22 and suspended the effective date of the tariffs until December 1, 2022, for further investigation.[6]

NSTAR Electric's service area comprises two geographic areas, designated as "EMA" (Eastern Massachusetts) and "WMA" (Western Massachusetts) (Exh. DPU 64-1, at 1). The service area designated as EMA encompasses the City of Boston and surrounding communities, extending west to Sudbury, Framingham, and Hopkinton, as well as

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[4] NSTAR Electric's filing also contained proposals regarding the review and treatment of certain grid modernization investments and costs associated with the Company's resiliency tree work program. On March 9, 2022, the Department issued an Interlocutory Order and removed these proposals from consideration in this docket. D.P.U. 22-22, Interlocutory Order on Scope of Proceeding (March 9, 2022).

[5] In D.P.U. 17-05, at 28-55, the Department approved the corporate consolidation of Western Massachusetts Electric Company with and into NSTAR Electric pursuant to G.L. c. 164, § 96. The legal name of Eversource Energy's electric distribution company in Massachusetts is NSTAR Electric Company d/b/a Eversource Energy.

[6] The rates and charges established in this proceeding will be for electricity consumed on or after January 1, 2023.

communities in southeastern Massachusetts extending from Marshfield south through Plymouth, Cape Cod, and Martha's Vineyard, and west through New Bedford and Dartmouth (Exh. DPU 64-1, at 1). Within this geographic area, the Company serves approximately 1.2 million residential and commercial and industrial ("C&I") customers in approximately 80 communities (Exh. DPU 64-1, at 1). The service area designated as WMA encompasses the City of Springfield ("Springfield") and surrounding communities, extending west to the New York border and north to Greenfield and the Vermont border (Exh. DPU 64-1, at 1). Within this geographic area, the Company serves approximately 209,000 residential and C&I customers in approximately 59 communities (Exh. DPU 64-1, at 1).

II. PROCEDURAL HISTORY

On January 18, 2022, the Attorney General of the Commonwealth of Massachusetts ("Attorney General") filed a notice of intervention pursuant to G.L. c. 12, § 11E(a). On February 9, 2022, the Department granted the petition to intervene as a full party filed by the Massachusetts Department of Energy Resources ("DOER"). On February 15, 2022, the Department granted the petition to intervene as a full party filed by the Low-Income Weatherization and Fuel Assistance Program Network ("Low-Income Network"). On March 1, 2022, the Department granted the separate petitions to intervene as full parties filed by: (1) Acadia Center; (2) Cape Light Compact JPE ("Cape Light Compact" or "CLC"); (3) Conservation Law Foundation ("CLF"); (4) Massachusetts Electric Company and Nantucket Electric Company, d/b/a National Grid ("National Grid (electric)"); (5) Northeast Clean Energy Council, Inc. ("NECEC"); and (6) The Energy Consortium ("TEC").

D.P.U. 22-22, Hearing Officer Ruling on Petitions for Intervention at 3-4 (March 1, 2022). On the same day, the Department allowed PowerOptions, Inc. ("PowerOptions") to participate as a limited intervenor. D.P.U. 22-22, Hearing Officer Ruling on Petitions for Intervention at 4-5 (March 1, 2022). The Department also allowed NRG Home f/k/a Reliant Energy Northeast LLC, Direct Energy Services, LLC, Direct Energy Business, LLC, Direct Energy Business Marketing, LLC, Green Mountain Energy Company, Energy Plus Holdings LLC, and XOOM Energy Massachusetts, LLC, and Walmart, Inc. ("Walmart") to participate as limited participants. D.P.U. 22-22, Hearing Officer Ruling on Petitions for Intervention at 5-6 (March 1, 2022).

On March 11, 2022, the Department allowed the University of Massachusetts ("UMass") to intervene as a full party. D.P.U. 22-22, Interlocutory Order on Appeals of Hearing Officer's Ruling on Petitions to Intervene by University of Massachusetts and Walmart, Inc. at 6-7 (March 11, 2022). On April 12, 2022, the Department allowed the Town of Barnstable ("Town" or "Barnstable") to participate as a limited intervenor. D.P.U. 22-22, Hearing Officer Ruling on Town of Barnstable Petition for Intervention at 4-6 (April 12, 2022).

Pursuant to notice duly issued, and consistent with certain ongoing safety measures and precautions relating to in-person events as a result of the COVID-19 pandemic, the Department held virtual public hearings on March 29, 2022, March 31, 2022, and May 4, 2022.[7] The Department held 14 days of virtual evidentiary hearings from June 29, 2022 through July 27, 2022.

In support of its filing, NSTAR Electric sponsored the testimony of the following witnesses, all of whom were employed by Eversource Service Company ("ESC"):[8] (1) Craig Hallstrom, president of regional electric operations for Connecticut and Massachusetts; (2) Douglas P. Horton, vice president of distribution rates and regulatory requirements; (3) Digaunto Chatterjee, vice president of system planning; (4) Lavelle A. Freeman, director of distribution system planning; (5) Gerhard Walker, principal engineer of system planning; (6) Penelope M. Connor, executive vice president of customer experience and energy strategy;[9] (7) Catherine Finneran, vice president of sustainability and environmental affairs; (8) Paul Renaud, vice president of engineering; (9) Robert W. Frank, former director of revenue requirements – Massachusetts;[10] (10) Ashley N. Botelho, director of revenue

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[7] The Department received oral and written comments during the public comment period.

[8] ESC performs functions such as accounting, auditing, communications, rates, legal, regulatory affairs, information technology, and human resources for NSTAR Electric and other Eversource Energy subsidiaries (Exhs. AG 1-26, Atts.). See also D.P.U. 17-05, at 163; NSTAR Gas Company, D.P.U. 19-120, at 269 (2020).

[9] Prior to evidentiary hearings, the Department was advised that Ms. Connor no longer would participate in the proceedings. Her testimony, supporting exhibits, and responses to information requests were adopted by Jared Lawrence, senior vice president, customer operations and digital strategy and chief customer officer.

[10] Prior to evidentiary hearings, Mr. Frank retired and his testimony, supporting exhibits, and responses to information requests were adopted by Ms. Botelho.

requirements – Massachusetts; (11) Sasha Lazor, director of compensation; (12) Michael P. Synan, director of benefits strategy and human resources shared services; (13) Leanne M. Landry, director of budget and investment planning; (14) John G. Griffin, director of corporate performance management;[11] (15) Jennifer A. Schilling, vice president of grid modernization; (16) William A. Van Dam, director of vegetation management; (17) Richard D. Chin, manager of rates; (18) Emilie O'Neil, assistant treasurer and director of corporate finance and cash management; (19) Elizabeth A. Foley, director of corporate performance management; and (20) Dennis Moore, information technology director of business solutions. NSTAR Electric also sponsored the testimony of the following external consultant witnesses: (1) Mark E. Meitzen, Ph.D., senior consultant at Laurits R. Christensen Associates, Inc.; (2) Nicholas A. Crowley, senior economist at Laurits R. Christensen Associates, Inc.; (3) Lawrence R. Kaufmann, Ph.D., president of LKaufmann Consulting, Inc. and senior advisor at Pacific Economics Group Research LLC and Black and Veatch Management Consulting; (4) Vincent V. Rea, managing director at Regulatory Finance Associates, LLC; (5) John J. Spanos, president of Gannett Fleming Valuation and Rate Consultants, LLC; and (6) Bruce R. Chapman, vice president at Christensen Associates Energy Consulting, LLC.

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[11] Prior to evidentiary hearings, the Department was advised that Mr. Griffin no longer would participate in the proceedings. His testimony, supporting exhibits, and responses to information requests were adopted by Sean Noonan, vice president of the program management office and next-generation delivery.

The Attorney General sponsored the testimony of the following witnesses: (1) David E. Dismukes, Ph.D., consulting economist at Acadian Consulting Group; (2) David P. Littell, Esq., shareholder at Bernstein Shur Sawyer & Nelson; (3) David J. Effron, consultant; (4) David J. Garrett, managing member at Resolve Utility Consulting, PLLC; (5) Helmuth W. Schultz, III, senior regulatory consultant at Larkin & Associates, PLLC; (6) John Defever, regulatory consultant at Larkin & Associates, PLLC; (7) J. Randall Woolridge, professor of finance at the Pennsylvania State University; and (8) Timothy Newhard, financial analyst at the Attorney General's Office of Ratepayer Advocacy.

Cape Light Compact sponsored the testimony of John D. Wilson, research director at Resource Insight, Inc.; and Kevin F. Galligan, president of Galligan Energy Consulting, Inc. National Grid (electric) sponsored the testimony of Daniel R. Marceau, director of asset management and engineering performance, National Grid USA Service Company, Inc. TEC and PowerOptions jointly sponsored the testimony of James Bride, principal of Energy Tariff Experts, LLC. UMass sponsored the testimony of the following witnesses: (1) Eben Perkins, vice president at Competitive Energy Services, LLC; (2) Richard Silkman, Ph.D., chief executive officer at Competitive Energy Services, LLC; (3) Raymond Jackson, director of the physical plant division at the UMass Amherst campus; (4) James O'Day, director of utilities, energy management, and laboratories for facilities at the UMass Boston campus; and (5) James Jerue, associate vice chancellor of facility management at the UMass Dartmouth campus.

On August 19, 2022, the Attorney General, DOER, the Low-Income Network, Acadia Center, Cape Light Compact, CLF, National Grid (electric), TEC and PowerOptions, and UMass submitted initial briefs.[12] On September 2, 2022, the Company filed an initial brief. On September 19, 2022, the Attorney General, DOER, Acadia Center, Cape Light Compact, TEC and PowerOptions, and UMass submitted reply briefs. On the same day, the Low-Income Network and CLF each submitted a letter in lieu of a reply brief. On September 27, 2022, the Company filed a reply brief. The evidentiary record consists of approximately 4,000 exhibits and responses to 99 record requests.

III. COMPANY'S TEST YEAR

A. Introduction

NSTAR Electric's revenue requirement component is based on a test year ending December 31, 2020 (Exhs. ES-REVREQ-1, at 12; ES-REVREQ-2, Sch. 2 (Rev. 4)). The Company's test year coincides with the onset of the COVID-19 pandemic, a public health crisis that has been compared to the 1918 influenza pandemic.[13] The significant economic

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[12] The Attorney General filed a revised initial brief on August 24, 2022, to remove an errant header and add missing punctuation.

[13] In the 1918 influenza pandemic, an estimated 500 million people were infected globally (1/3 of the global population) with an estimated 50 million deaths, with 675,000 occurring in the U.S. https://www.cdc.gov/flu/pandemic-resources/1918-commemoration/1918-pandemic-history.htm. In the COVID-19 pandemic, an estimated 642 million people have been infected globally with an estimated seven million deaths, with over one million deaths occurring in the U.S. https://www.worldometers.info/coronavirus (last visited: November 18, 2022).

disruption associated with the pandemic has adversely affected individuals as well as businesses, particularly small businesses. Inquiries of the Department of Public Utilities regarding the COVID-19 Pandemic, D.P.U. 20-58-D/D.P.U. 20-91, Interim Order on Ratemaking Proposal and Vote and Order Opening Investigation at 5 (December 31, 2020); D.P.U. 20-58, Order Opening Inquiry and Establishing Working Group at 2 (May 11, 2020).

The pandemic also has affected the financial position of jurisdictional electric, gas, and water distribution companies, and utilities throughout the country. D.P.U. 20-58-D/D.P.U. 20-91, Interim Order on Ratemaking Proposal and Vote and Order Opening Investigation at 5 (December 31, 2020). NSTAR Electric, as well as other utilities, face shifts in demand and usage, increased operational burdens, collections shortfalls, and voluntary and mandatory moratoriums on disconnections. These issues affect cash flow, which result in increased short-term borrowings amidst uncertain financial markets. D.P.U. 20-58-D/D.P.U. 20-91, Interim Order on Ratemaking Proposal and Vote and Order Opening Investigation at 5 (December 31, 2020).

B. Analysis and Findings

It is well-established Department precedent that base distribution rate filings are based on an historic test year, adjusted for known and measurable changes. NSTAR Gas Company, D.P.U. 14-150, at 45 (2015); Investigation into Rate Structures that Promote Efficient Deployment of Demand Resources, D.P.U. 07-50-A at 52-53 (2008); Massachusetts Electric Company, D.P.U. 18204, at 4 (1975); see also Massachusetts Electric Company v. Department of Public Utilities, 383 Mass. 675, 680 (1981). In establishing rates pursuant to

G.L. c. 164, § 94, the Department examines a test year on the basis that the revenue and expense figures adjusted for known and measurable changes, and rate base figures during that period, provide the most reasonable representation of a distribution company's present financial situation, and fairly represent its cost to provide service. Plymouth Water Company, D.P.U. 14-120, at 9 (2015); Ashfield Water Company, D.P.U. 1438/1595, at 3 (1984).

The selection of the test year is largely a matter of a distribution company's choice, subject to Department review and approval. Fitchburg Gas and Electric Light Company, D.P.U. 15-80/D.P.U. 15-81, at 145-146 (2016), citing D.P.U. 07-50-A at 51; Boston Edison Company, D.P.U. 1720, Interlocutory Order at 7-11 (January 17, 1984). The Department requires that the historic test year represent a twelve-month period that does not overlap with the test year used in a previous rate case unless there are extraordinary circumstances that render a previous Order confiscatory. D.P.U. 14-150, at 45 n.26; Massachusetts Electric Company, D.P.U. 19257, at 12 (1977). The test year is generally the most recent twelve-month period for which financial information exists. D.P.U. 14-150, at 45 n.26; Boston Edison Company v. Department of Public Utilities, 375 Mass. 1, 24, cert. denied, 439 U.S. 921 (1978). The Department has a strong preference for calendar test years. D.P.U. 17-05, at 28; Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 15-155, at 22 (2016); D.P.U. 14-120, at 16 & n.11.

In this case, the Company has selected a calendar 2020 test year. No party has objected to the Company's selected test year. While the use of a different test year, such as a split test year,[14] may have mitigated some of the effects of the pandemic on the Company's rate filing, the societal and financial effects of the pandemic remain ongoing. Moreover, the use of an earlier test year such as 2019 for a rate increase that would take effect in 2023 would be fraught with its own challenges given the staleness of the data. On this basis, the Department concludes that there is no reasonable alternative test year that would insulate NSTAR Electric's operations from the effects of the pandemic.[15]

The Company has made numerous adjustments to its test-year revenues, expenses, and plant in preparing its rate filing (Exhs. ES-REVREQ-1, at 13-14; ES-REVREQ-2, Schs. 7, 9 (Rev. 4)). Such adjustments are a routine part of rate case proceedings. In reviewing these adjustments, the Department recognizes that some year-to-year variation is expected, even when comparing individual functions and accounts over corresponding time periods. Boston Gas Company, D.P.U. 20-120, at 16 (2021). As discussed in Section VII.H below, the Company has been deferring incremental expenditures related to COVID-19 response efforts (Exhs. ES-REVREQ-2, Sch. 9, at 1 (Rev. 4); DPU 3-2; AG 21-1, Att.; AG 1-34, Att. (h)

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[14] A test year that spans two calendar years, as opposed to a test year based on a calendar year, is often referred to as a "split" test year. D.P.U. 14-150, at 45 n.26; D.P.U. 14-120, at 12, 16. A test year, whether a calendar year test year or a "split" test year, comprises a period of twelve consecutive calendar months.

[15] In rare cases, the Department has relied on different test years than those proposed by the utility. McNamara Water System, D.P.U. 91-196, at 4-5 (1992); Hutchinson Water Company, D.P.U. 85-194, at 3-4 (1986). In these cases, however, the petitioners' cases-in-chief consisted of a few pages of prefiled testimony from a single witness. In contrast, NSTAR Electric's own case-in-chief consists of thousands of pages of prefiled testimony and exhibits from over 20 witnesses.

at 7, Att. (i) at 5). To the extent that the pandemic continues to affect the Company's operations, such as in lower C&I revenues, increased write-offs, and ongoing COVID-19 response expenditures, these issues are fully addressed in the respective sections of this Order.

Based on the foregoing analysis, the Department finds that while the effects of the pandemic upon NSTAR Electric's operations have added to the intricacies of the Company's rate filing, the Company's proposed test year is nonetheless reviewable and reliable. Therefore, the Department accepts NSTAR Electric's selection of a calendar year 2020 test year.

IV. PERFORMANCE BASED RATEMAKING PROPOSAL

A. Introduction

In D.P.U. 17-05, at 370-414, the Department approved a PBR mechanism with a five-year term for the Company. The PBR mechanism allowed NSTAR Electric to adjust its distribution rates annually through the application of a revenue-cap formula that accounts for, among other factors, inflation and events beyond the Company's control that have a significant effect on its revenue requirement ("exogenous events"), either positive or negative. D.P.U. 17-05, at 381-399. The PBR mechanism included a productivity offset, or "X factor," of -1.56 percent. D.P.U. 17-05, at 381-392. Further, the PBR mechanism included a 25-basis point (or 0.25 percent) consumer dividend as a deduction to the adjustment when inflation exceeded two percent. D.P.U. 17-05, at 394-395. The PBR mechanism also included an earnings-sharing mechanism ("ESM") that incorporated a

200-basis point threshold above the Company's authorized return on equity ("ROE") of 10.0 percent. D.P.U. 17-05, at 399-401, 713.[16]

As discussed in further detail below, in the instant proceeding, the Company proposes to renew its PBR plan with certain modifications. In its initial filing, NSTAR Electric proposed a PBR mechanism with a revenue cap formula and the following components: (1) a ten-year term with a five-year, mid-term "rate schedule filing" to meet the requirements of G.L. c. 164, § 94; (2) an X factor of -1.45 percent; (3) an annual inflation index based on the Gross Domestic Product Price Index ("GDP-PI");[17] (4) a proposed consumer dividend to provide a "stretch factor," applicable when inflation equals or exceeds two percent; (5) a rate base roll-in for 2021 and 2022 capital investments; (6) an ROE risk factor ("ROERA") triggered by significant changes up or down in Treasury rates; (7) cost treatment in the second five years of the PBR plan for critical infrastructure; (8) an ESM consistent with that approved for affiliate NSTAR Gas Company ("NSTAR Gas") in NSTAR Gas Company, D.P.U. 19-120 (2020); and (9) an exogenous cost provision that, in particular, would allow

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[16] If the Company's calculated, earned distribution ROE was at or below the threshold (i.e., 12.0 percent), the Company was not required to share any earnings. D.P.U. 17-05, at 401. If the Company's earned distribution ROE exceeded the threshold, shareholders and ratepayers shared any earnings above the threshold at 25 percent and 75 percent, respectively. D.P.U. 17-05, at 401.

[17] GDP-PI is a measure of inflation in the price of goods and services produced in the United States published quarterly by the U.S. Department of Commerce, Bureau of Economic Analysis.

for recovery for certain property tax and information technology ("IT") expenses (Exhs. ES-CAH/DPH-1, at 13, 62-93; ES-PBR/PLAN-1, at 4-14).

The Company's initial filing also included an alternative PBR plan proposal, which was modified during the proceeding (Exhs. ES-CAH/DPH-1, at 93; DPU 1-1; DPU 5-1). NSTAR Electric proposed that, for a five-year term, the following modifications would apply: (1) only capital additions completed through December 31, 2021 would be eligible for a rate-base roll-in and those additions would be included in base distribution rates set in this proceeding; (2) the ROERA would not apply;[18] (3) the ESM would be asymmetrical with upside sharing for customers but no downside adjustment for the Company (Exh. DPU 1-1). The remaining proposed PBR mechanism components applicable to a ten-year PBR term would apply to a five-year term (Exhs. ES-CAH/DPH-1, at 93; DPU 1-1; DPU 5-1).

As part of its rebuttal testimony, the Company revised its initial proposed PBR mechanism to address concerns raised by the Attorney General (Exh. ES-PBR-Rebuttal-1, at 41-50). The Company still proposed a revenue cap formula with a ten-year PBR plan term, but the initial proposal was modified to: (1) reduce the X factor to zero; (2) increase the consumer dividend; (3) cap eligible inflation as tracked by GDP-PI to five percent; (4) eliminate the cost treatment for the critical infrastructure; (5) eliminate the proposed

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[18] In Exhibit DPU 5-1, the Company stated that the ROERA would apply to a PBR plan with a five-year term. On brief, however, when summarizing the components of a five-year term, the Company did not include the ROERA in the proposal (see, e.g., Company Brief at 16 n.2, 19 n.6). In any event, as discussed in Section IV.D.5.f below, the Department disallows the proposed ROERA.

roll-in of 2022 capital additions; and (6) implement a "K-bar" formula approach (see n.21 below) for capital investment support between rate cases, beginning January 1, 2024, the date of the first PBR adjustment (Exh. ES-PBR-Rebuttal-1, at 45).[19] The Department discusses these proposals below.

B. PBR Mechanism Components

1. PBR Plan Term

The Company initially proposed a ten-year PBR term with a mid-term filing of rate schedules at the five-year mark (Exhs. ES-CAH/DPH-1, at 13, 93; ES-PBR/PLAN-1, at 13). Alternatively, the Company proposed a five-year plan term, with certain modifications to the ratemaking mechanisms (Exhs. ES-CAH/DPH-1, at 93; DPU 1-1; DPU 5-1). As noted above, during the proceedings the Company revised certain components of its proposed PBR plan. The Company, however, did not revise the term of its PBR plan and proposed to maintain the ten-year term (Exh. ES-PBR-Rebuttal-1, at 45).

2. Productivity Offset

The Company initially proposed a productivity offset, or X factor to be calculated as:

$X = [(\% \ TFP^{R}_{1} - \% \ TFP_{E}) + (\% \ W_{E} - \% \ W_{1})$, where

$\% \ TFP^{R}_{1}$ is the percentage change in electric distribution industry total factor productivity growth;

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[19] As discussed in Section V.B below, the Company also proposed a set of performance metrics to be implemented in conjunction with the PBR plan. The proposed PBR metrics are the same under both the initially proposed PBR plans (i.e., the plan with a ten-year or five-year term) and the revised proposed PBR plan with a ten-year term.

% TFP_E is the percentage change in economy wide total factor productivity growth;

% W_E is the percentage change in economy-wide input price growth; and

% W_1 is the percentage change in electric distribution industry input price growth.

(Exh. ES-PBR/TFP-1, at 15).

The X factor consists of a differential in a measure of the expected rate of productivity change between the electric distribution industry and the overall economy, and a differential in input price growth between the overall economy and the electric distribution industry (Exh. ES-PBR/TFP-1, at 12). To determine the proposed X factor, the Company conducted a productivity study of U.S. electric distribution total factor productivity ("TFP") and input price growth over the period 2006 through 2020 (Exh. ES-PBR/TFP-1, at 20). The Company used two different samples for its productivity study: (1) a sample of 65 electric distribution companies ("EDCs") intended to represent the overall U.S. electric distribution industry ("nationwide EDCs"); and (2) a sample of 17 EDCs intended to represent the electric distribution industry in the Northeast U.S. ("regional EDCs") (Exh. ES-PBR/TFP-1, at 20). For economy-wide TFP and input price growth, the Company used official U.S. government sources (Exh. ES-PBR/TFP-1, at 20).

The TFP is generally defined as the ratio of total output to total input (Exh. ES-PBR/TFP-1, at 13). Total output consists of all the services produced by the relevant unit of production (Exh. ES-PBR/TFP-1, at 13). Total input includes all resources used by the unit of production in providing those services (Exh. ES-PBR/TFP-1, at 13). The Company used number of customers as the sole productivity study output measure

(Exh. ES-PBR/TFP-1, at 13). The Company constructed a quantity index of total input for each firm and each year based on capital, labor, and materials (Exh. ES-PBR/TFP-1, at 13). The Company has also incorporated customer accounts and sales expenses and administrative and general costs into the TFP model (Exh. ES-PBR/TFP-1, at 17).

The results of the Company's study indicate that, for the period 2006 through 2020, the average growth in productivity for the regional EDCs was equal to -0.05 percent, while the average productivity growth for the nationwide EDCs was equal to 0.06 percent (Exh. ES-PBR/TFP-1, at 24-25). For the same period, the average input price growth for regional EDCs was equal to 3.11 percent, while the average input price growth for the nationwide EDCs was equal to 3.17 percent (Exh. ES-PBR/TFP-1, at 24-25). The Company's productivity study indicates that the economy-wide average productivity growth from 2006 through 2020 was 0.34 percent, and the average input price growth was 2.0 percent (Exh. ES-PBR/TFP-1, at 23).

The Company calculated its proposed productivity offset using the productivity and input price growth indices for the nationwide EDCs rather than the regional EDCs (Exh. ES-PBR/TFP-1, at 27). Inputting the results of the productivity study into the productivity formula, the Company calculated a proposed X factor of -1.45 percent (Exh. ES-PBR/TFP-1, at 24).

As noted above, during the proceeding, the Company proposed to modify certain components of the proposed PBR plan (Exh. ES-PBR-Rebuttal-1, at 44-45). In particular, the Company proposed to reduce the X factor to zero, as recommended by the Attorney

General (Exh. ES-PBR-Rebuttal-1, at 44-45, citing Exhs. AG-DED-PBR-1, at 3, 58; AG-DPL-1, at 12).

3. Inflation Index and Floor

The Company initially proposed to base the price inflation index included in the revenue cap formula on the GDP-PI as measured by the U.S. Commerce Department (Exhs. ES-CAH/DPH-1, at 67; ES-PBR/PLAN-1, at 5). Under the Company's proposal, the inflation index would be calculated as the percentage change between the current year's GDP-PI and the prior year's GDP-PI (Exhs. ES-CAH/DPH-1, at 67; ES-PBR/PLAN-1, at 5). For each year, the GDP-PI would be calculated as the average of the most recent four quarterly measures of GDP-PI as of the second quarter of the year (Exhs. ES-CAH/DPH-1, at 67; ES-PBR/PLAN-1, at 5). Additionally, the Company proposed an inflation "floor" equivalent to the X factor of -1.45 percent so that a negative PBR adjustment would not occur (Exh. ES-CAH/DPH-1, at 68).

In its rebuttal testimony, the Company proposed to modify the requested inflation factor. Specifically, NSTAR Electric proposed to cap the factor at five percent, and the Company stated that it would "make sense" to have the opportunity to file a base distribution rate case if reported earnings fall more than 400 basis points below the ROE authorized in the instant proceeding (Exhs. ES-PBR-Rebuttal-1, at 45; DPU 35-1).

4. Consumer Dividend

The Company initially proposed to include a consumer dividend of 15 basis points, or 0.15 percent, when inflation, as calculated in the proposed PBR formula, exceeds two percent (Exhs. ES-CAH/DPH-1, at 72; ES-PBR/PLAN-1, at 38). The Company stated that its proposed consumer dividend was intended to share the financial benefits of increased productivity growth with customers, and that the continuance of an existing PBR plan warrants a lower consumer dividend than at the outset of a PBR plan (Exhs. ES-CAH/DPH-1, at 73; ES-PBR/PLAN-1, at 37, 44).

In its rebuttal testimony, the Company proposed to modify the requested consumer dividend. Specifically, the Company proposed to raise the consumer dividend to 25 basis points, or 0.25 percent, when inflation exceeds two percent (Exh. ES-PBR-Rebuttal-1, at 45).

5. Post-Test-Year Capital Additions

The Company initially proposed to include post-test-year capital additions into base distribution rates at two different intervals during the term of the proposed PBR plan (Exh. ES-CAH/DPH-1, at 74-75). First, the Company proposed that the base distribution rates effective January 1, 2023, would include in rate base plant additions placed into service through December 31, 2021 (Exh. ES-CAH/DPH-1, at 74-75). As part of this proposal the Company would adjust base distribution rates for depreciation expense, return on rate base, associated federal and state income taxes, property taxes, and revenues for all capital additions ending December 31, 2021 (Exh. ES-CAH/DPH-1, at 75). Second, the Company proposed as part of the first annual PBR plan filing for rates effective January 1, 2024, to include in rate base the calendar year 2022 capital additions along with the associated accumulated depreciation (Exh. ES-CAH/DPH-1, at 75).[20]

In its rebuttal testimony, the Company modified its capital roll-in proposal. Specifically, the Company proposed to eliminate the roll-in of the 2022 calendar year capital additions from the first annual PBR plan filing (Exh. ES-PBR-Rebuttal-1, at 45). Further, the Company proposed as part of the revised PBR formula, a K-bar adjustment[21] that would allow additional revenues to be collected through the PBR adjustments, beginning January 1, 2024, to provide additional funding for capital investments (Exhs. ES-PBR-Rebuttal-1, at 45; DPU 63-3 & Atts.; RR-DPU-12 & Atts.). The K-bar approach would establish a level of eligible capital recovery based on a historical average of capital additions that went into service under operation of the Company's current PBR plan, approved in D.P.U. 17-05, for the years in which that I-X factor was applicable, escalated to current year dollars

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[20] As noted above, under a five-year PBR plan, the Company proposed to roll-in only capital additions placed in service through December 31, 2021, and those additions would be included in base distribution rates set in this proceeding (Exh. DPU 1-1).

[21] In 2016, the Alberta Utilities Commission ("AUC") developed a "K-bar" approach to supplemental capital funding for Alberta electric distribution utilities (Exh. DPU 35-5, at 3, citing AUC docket 20414-D01-2016 (December 16, 2016)). The AUC amended its K-bar method in 2018 (Exh. DPU 35-5, at 3, citing AUC docket 22394-D01-2018, (February 5, 2018)). Under this approach, the I-X PBR formula escalates historical average capital additions not subject to recovery through capital trackers to form the basis of future approved capital recovery (Exh. DPU 35-5, at 3-4). Recoverable capital expenditures are obtained from the differential between the utility's escalated historical capital needs and what each utility actually will collect under the I-X PBR formula for these types of capital additions (Exh. DPU 35-5, at 4). The AUC calls this differential the "K-bar" (Exh. DPU 35-5, at 4).

(RR-DPU-12). Specifically, under the Company's revised proposal, the K-bar revenue requirement would be calculated by rolling forward 2018 through 2022 plant additions, cost of removal, and retirements that occurred during the current PBR plan and then calculating a revenue requirement based on that theoretical rate base calculation (RR-DPU-12). The K-bar revenue requirement is then compared to the capital investment costs approved in the instant proceeding and adjusted to 2023 costs using the PBR mechanism approved in the instant proceeding to establish the incremental K-bar revenue support (RR-DPU-12).

6. ROERA Factor

The Company initially proposed to include in the PBR plan an ROERA mechanism to recover costs arising from changes in the capital markets during the ten-year PBR term (Exhs. ES-CAH/DPH-1, at 76; ES-PBR/PLAN-1, at 8). The ROERA would be triggered, and a rate adjustment would take place, if the yield on the ten-year Treasury bond reaches 200 basis points above or below the yield in effect at the start of the PBR plan (Exh. ES-CAH/DPH-1, at 76-77). The Company states that the ROERA adjustment would apply only to rate base approved at the outset of the PBR plan and not for additions made while the PBR plan is in effect (Exh. ES-PBR/PLAN-1, at 12).

The proposed adjustment would take place in accordance with the following formula:

$CAP(t) = [RB(t)*EQ_0 *(TB(t)-TB_0)] / (1-CT_0)$

$CAP(t)$ is the capital cost adjustment in year t

RB_0 is the rate base in year zero (<u>i.e.</u>, the outset of the PBR plan)

EQ_0 is equity's share of rate base in year zero

TB (t) is the yield to maturity on the ten-year Treasury bond in year t

TB_0 is the yield to maturity on the ten-year Treasury bond in year zero

CT_0 is the combined tax rate in year zero

(Exh. ES-PBR/PLAN-1, at 11-12).

As noted above, if a five-year PBR plan term is approved, the Company proposed that the ROERA would not apply (Exh. DPU 1-1). In its rebuttal testimony, the Company did not propose to revise or remove the proposed ROERA from the revised PBR plan (Exh. ES-PBR-Rebuttal-1, at 45).

7. Cost Treatment of Critical Infrastructure

In its initial filing, NSTAR Electric stated that forecasted customer demand and incremental electrification demand over the PBR term will necessitate the Company to make major critical infrastructure investments (Exh. ES-CAH/DPH-1, at 77). In particular, NSTAR Electric stated that it intended to complete "major infrastructure projects," including substations and new circuits across the Company's service territory, over the next ten years at an estimated cost of $956 million (Exhs. ES-CAH/DPH-1, at 79-80; ES-ENG-3). The Company stated that it could not commit to a ten-year PBR term without a plan for cost treatment of the revenue requirement associated with these projects (Exh. ES-CAH/DPH-1, at 81). Thus, the Company initially proposed as part of its PBR plan to file for recovery of these costs at three specific intervals over the course of the ten-year PBR term (Exh. ES-CAH/DPH-1, at 82). Under this proposal, the Company would collect the revenue requirement associated with project costs that are reviewed and approved by the Department through a factor included in the PBR mechanism (Exh. ES-CAH/DPH-1, at 82-83).

In its rebuttal testimony, the Company proposed to eliminate the specific cost recovery factor associated with the aforementioned critical infrastructure projects (Exh. ES-PBRRebuttal-1, at 45). Instead, the Company proposed to receive investment support for the costs associated with these projects through the proposed K-bar adjustment (Exh. ES-PBR-Rebuttal-1, at 45).

8. ESM

The Company initially proposed to adopt an ESM consistent with the design approved for NSTAR Gas in D.P.U. 19-120 (Exhs. ES-CAH/DPH-1, at 90; ES-PBR/PLAN-1, at 12). Specifically, the proposed ESM would trigger a sharing with customers on a 75/25 percent basis (75 percent to customers and 25 percent to the Company) where the computed distribution ROE exceeds 100 basis points above the ROE authorized in this proceeding (Exhs. ES-CAH/DPH-1, at 90; ES-PBR/PLAN-1, at 12). If the computed distribution ROE is between 150 and 200 basis points below the authorized ROE, sharing with customers would be triggered on a 50/50 percent basis (50 percent to ratepayers and 50 percent to shareholders) (Exhs. ES-CAH/DPH-1, at 90; ES-PBR/PLAN-1, at 12). If the computed distribution ROE exceeds 200 basis points below the authorized ROE, sharing with customers would be triggered on a 75/25 percent basis (75 percent to customers and 25 percent to the Company) (Exhs. ES-CAH/DPH-1, at 90; ES-PBR/PLAN-1, at 12). The Company proposes that for any year in which the ROE is above or below the bandwidth, the percentage of earnings that is to be shared with customers would be credited to customers in the succeeding year and that the impact of this prior year's adjustment would be excluded from the calculation of the subsequent year's sharing (Exh. ES-CAH/DPH-1, at 91). The Company acknowledged that any ESM adjustment would be subject to a full investigation in an adjudicatory proceeding (Exh. ES-CAH/DPH-1, at 92).

As noted above, if a five-year PBR term is approved, the ESM would be asymmetrical with upside sharing for customers, but no downside adjustment for the Company (Exh. DPU 1-1). In its rebuttal testimony, the Company did not propose to revise or remove the proposed ESM from the revised ten-year PBR plan (Exh. ES-PBR-Rebuttal-1, at 45).

9. Exogenous Cost Factor

NSTAR Electric initially proposed to include in the PBR adjustment formula an exogenous cost provision (or "Z factor"), which was defined as positive or negative changes to operating costs that are beyond the Company's control and not reflected in the GDP-PI or other elements of the PBR adjustment formula (Exhs. ES-CAH/DPH-1, at 83-84; ES-PBR/PLAN-1, at 7). The Company would calculate the exogenous cost factor as a percentage of the previous year's base revenues (Exh. ES-CAH/DPH-1, at 83).

The Company proposed that to be eligible for exogenous cost recovery the cost change must: (1) be beyond the Company's control; (2) arise from a change in accounting requirements or regulatory, judicial, or legislative directives or enactments; (3) be unique to the electric distribution industry as opposed to the general economy; and (4) meet a threshold of "significance" for qualification (Exhs. ES-CAH/DPH-1, at 83-84; ES-PBR/PLAN-1, at 7; ES-RDC-6, Sch. 1, at 455). The Company anticipated two types of future costs that might apply for exogenous cost recovery: (1) incremental property taxes arising from a municipality's change in valuation method for assessing utility property; and (2) expenses incurred for certain Enterprise IT investments (Exh. ES-CAH/DPH-1, at 85-86). The Company proposed the significance threshold for exogenous costs to be set at $4 million in 2023 and adjusted annually by the change in GDP-PI, except for exogenous costs associated with Enterprise IT expenses, for which the initial threshold would be set at $6 million (Exhs. ES-CAH/DPH-1, at 84-86; ES-PBR/PLAN-1, at 7; ES-RDC-6, Sch. 1, at 455). The Company did not revise this aspect of the proposed PBR mechanism during the proceedings.

C. Positions of the Parties

1. Attorney General

The Attorney General raises a number of issues with the Company's initially proposed, and modified, PBR plans. First, the Attorney General argues that the Company's TFP results and resulting initially-proposed X factor are flawed (Attorney General Brief at 26). In particular, the Attorney General contends that the X factor approved in D.P.U. 17-05 has resulted in over-collection of $124 million in the past five years and, despite the Company's efforts to improve the TFP study in this proceeding, there is no accounting for this over-collection (Attorney General Brief at 26-27). The Attorney General also claims that NSTAR Electric's initially proposed X factor of -1.45 percent is overstated because the TFP study did not exclude costs that the Company proposes to remove from the base rate revenue requirement and the PBR formula (Attorney General Brief at 27-30, citing Exh. ES-RDC-6, Sch. 1, at 127, 452-454; Tr. 4, at 323-327; RR-AG-8).[22] Further, the Attorney General asserts that the TFP study is not robust and, therefore, produces hypersensitive and exaggerated results (Attorney General Brief at 30). In addition, the Attorney General contends that the TFP study and resulting X factor are unreliable because the study inappropriately relies on customer count as an output, which she asserts is not an accurate indicator of cost causation (Attorney General Brief at 30-33).

Second, the Attorney General challenges the Company's benchmarking study and initially proposed consumer dividend of 0.15 percent (Attorney General Brief at 33-36). The Attorney General argues that the limited time frame of NSTAR Electric's benchmarking study (i.e., 2018 through 2020) produces more favorable results for the Company than would a more robust study that uses a longer time frame and more data points (Attorney General Brief at 33). In this regard, she contends that the longer time frame used in her witness's benchmarking study, which resulted in a consumer dividend of 0.25 percent, provides the Department with a more accurate comparison between NSTAR Electric's investment and cost performance and the Company's peers (Attorney General Brief at 33-34, citing Exh. AG/DED-4, Schs. 4, 5). Further, the Attorney General claims that the Company's lack

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[22] These costs include those associated with energy efficiency, grid modernization and capital additions, advanced metering infrastructure, storm restoration, vegetation management, pension and post-retirement benefits other than pensions, substation capital additions, customer information systems, and IT additions (Attorney General Brief at 29).

of specific and measurable results to show improved efficiency, and the malleability of the Company's benchmarking study, are indicative of a misalignment with long-standing Department precedent (Attorney General Brief at 35-36, citing Incentive Regulation, D.P.U. 94-158, at 63 (1995)). Accordingly, the Attorney General recommends that the Department reject the initially proposed consumer dividend of 0.15 percent and adopt a 0.25-percent consumer dividend, in the event that the Department approves a PBR plan for the Company (Attorney General Brief at 35).

Third, the Attorney General argues that the Company's proposed K-bar adjustment will result in additional rate increases under the proposed PBR plan and will provide little incentive for cost control (Attorney General Brief at 23). Further, the Attorney General contends that a K-bar structured with a historical average based on the years 2018 through 2022 is flawed, because 2022 capital additions have not been subject to prudency review and the Company could improperly increase 2022 spending as a means to increase its future revenue under its K-bar (Attorney General Brief at 24). The Attorney Generals also claims that there is uncertainty regarding the historical capital plant additions used by NSTAR Electric to calculate its proposed K-bar formula (Attorney General Brief at 25). She asserts that NSTAR Electric's proposed K-bar adjustment includes $114 million in additional capital for the years 2018-2019 that was not reflected in the Company's TFP calculations (Attorney General Brief at 25). Based on these considerations, the Attorney General argues that, if the Department approves a PBR plan for the Company, a K-bar structured with a historical average from the years 2017 through 2021 is the more appropriate option (Attorney General Brief at 24, 65).[23]

Fourth, the Attorney General raises concerns regarding the Company's proposed ROERA. In particular, the Attorney General argues that the proposed ROERA is unnecessary, as the Company already is compensated for changes in O&M expenses and capital costs via the annual rate increases provided by the I-X formula (Attorney General Brief at 36). Further, the Attorney General contends that the proposed ROERA is an attempt to expand the well-established definition of what qualifies as an exogenous cost event and allowing this adjustment along with a Z factor will dilute the original purpose behind "truly exogenous events" (Attorney General Brief at 37, citing D.P.U. 17-05, at 395-396). In addition, the Attorney General claims that the Company failed to provide any support for using the ten-year U.S. Treasury bond in calculating the ROERA adjustment, while the Attorney General's witnesses established that the 30-year U.S. Treasury Bond yield is a better representation of the long-run expectations of investors (Attorney General Brief at 38, citing Exhs. AG-JRW-1, at 13, 18, 58; ES-VVR-1, at 16, 17, 26, 55; ES-VV-5, at 1; Tr. 9, at 1012-1013). For these reasons, the Attorney General recommends that the Department reject the Company's proposed ROERA adjustment (Attorney General Brief at 38).

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[23] The Attorney General contends that the 2017 through 2021 average includes an additional $82 million in capital additions not reflected in the Company's TFP calculations (Attorney General Brief at 25).

Fifth, the Attorney General acknowledges that the Company needs to carefully undertake its future distribution system planning to accommodate the Commonwealth's emissions reduction goals and clean energy requirements (Attorney General Brief at 57). The Attorney General, however, argues that the Company's critical infrastructure projects are loosely defined and are only in the early stages of planning (Attorney General Brief at 58). Further, she contends that the circumstances surrounding when the Company could seek cost recovery for these projects are vague, lack meaningful restrictions or requirements, and present oversight challenges (Attorney General Brief at 58-59). Finally, the Attorney General argues that NSTAR Electric's proposal is unnecessary because legislative action already requires the Company to make various investments in reliability, resiliency, and general electrification and there likely will be overlap between these requirements and the Company's proposed capital investments (Attorney General Brief at 59, citing An Act Driving Clean Energy and Offshore Wind, St. 2022, c. 179, § 53, ("2022 Clean Energy Act")). For these reasons, the Attorney General asserts that the Company's initial proposal to include a cost recovery factor for critical infrastructure investments should be rejected (Attorney General Brief at 59).

Sixth, the Attorney General argues that the Department should reject the Company's proposed inclusion of certain Enterprise IT expenses in the exogenous cost factor (Attorney General Brief at 59). In support of this argument, the Attorney General contends that ESC, rather than the Company, will incur the costs for most of these investments (Attorney General Brief at 59). Further, she claims that the Company already is compensated for IT costs through base distribution rates and the annual PBR adjustments (Attorney General Brief at 60). In addition, the Attorney General asserts that the Company does not recognize or net out any economic benefits that accrue as a result of the implementation of the new IT systems (Attorney General Brief at 60).

Next, the Attorney General makes several arguments, in the context of the proposed PBR plan and annual PBR adjustment, against the Company's request to transfer the Solar Expansion Program investments to base distribution rates (Attorney General Brief at 113-117, citing Exh. AG-TN-1, at 4-10).[24] In particular, she contends that the Company's proposal would provide a windfall to shareholders because the amounts collected from customers for the Solar Expansion Program investments would increase over time due to the PBR adjustment while the actual costs to the Company for those investments would decrease as the Company recovers its investment (Attorney General Brief at 113-116, citing Exh. AG-TN-1, at 4-8). Further, the Attorney General argues that the Solar Expansion Program costs are generation costs, not distribution costs (Attorney General Brief at 116-117, citing Exh. AG-TN-1, at 9). Thus, according to the Attorney General, these costs should not be included in the base distribution rate revenue requirement portion of the PBR rate formula and applying a PBR adjustment to these generation-related costs would be inappropriate (Attorney General Brief at 117, citing Exh. AG-TN-1, at 9-10).

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[24] The Attorney General raised similar arguments as to the Company's proposed SMART Program investments and Solar Program investments (Attorney General Brief at 113-117). The Department addresses these programs and the treatment of the investments in Section XIV below.

Finally, the Attorney General argues that numerous provisions in the Company's proposed PBR plan tariff should be revised to provide appropriate definitional and clarifying language (Attorney General Brief at 60-61). She asserts that each of her recommended changes should be adopted should the Department allow a PBR plan for the Company (Attorney General Brief at 61).

Based on the above considerations, the Attorney General argues that the Company's proposed PBR plans will impose unnecessary rate increases on customers and focus too heavily on meeting projected increased peak demand through increased capital expenditures (Attorney General Brief at 14-15, 18-26, 62-64). Thus, the Attorney General asserts that the Department should reject the PBR plan in lieu of an all-in capital tracker (Attorney General Brief at 10, 64-65; Attorney General Reply Brief 1-3). According to the Attorney General, the all-in capital tracker would: (1) fully compensate the Company for investments that the Company actually makes; (2) be simple to understand, account for, and administer; (3) consolidate into one filing all other capital costs currently being recovered through reconciling mechanisms; (4) incorporate the required cost recovery without additional filings for legislatively-mandated investments (Attorney General Brief at 8-10). Further, the Attorney General asserts that the Department has successfully used capital trackers in the past (Attorney General Brief at 9, citing D.P.U. 15-80/D.P.U. 15-81, at 44–55; Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 09-39, at 78-84 (2009)). Alternatively, if the Department approves a PBR plan for the Company, the Attorney General asserts that the plan should include the following modifications: (1) an X factor equal to zero; (2) a consumer dividend of at least 25 basis points; (3) a cap on the inflation factor of five percent; (4) inclusion of a K-bar formula approach based on average historical capital expenditures for the five-year period of 2017 through 2021, and elimination of the 2022 capital roll-ins; and (5) elimination of the critical infrastructure cost recovery factor and exogenous cost treatment for Enterprise IT expenses (Attorney General Brief at 65).

2. DOER

DOER recommends approving a PBR plan for the Company, but with modifications (DOER Brief at 9-10). First, DOER argues that the Department should approve a five-year plan term and reject the Company's proposed ten-year term (DOER Brief at 9-10). DOER asserts that a ten-year PBR plan would carry significant risk and that it would inhibit the ability of regulators and legislators to ensure that rates are aligned with the needs of the clean energy transition (DOER Brief at 10-11). Further, DOER argues that the Company's involvement with multiple large-scale investment proceedings necessitates a shorter-term length so that ratemaking structures can be responsive to the needs of the clean energy transition (DOER Brief at 11-12). DOER also contends that NSTAR Electric's assumptions in modeling demand growth may require revision in the future and that a five-year term would better allow the Company and Department to adjust planned investments as needed (DOER Brief at 13). Additionally, DOER claims that a five-year term is more consistent with Department precedent (DOER Brief at 10). Finally, DOER asserts that the elimination of full revenue decoupling will need to be addressed in the near future, and that a five-year term will enable the Company to be more responsive to this change than a ten-year term would be (DOER Brief at 13-14).

Second, DOER supports the Attorney General's proposal for a broad-based capital tracker mechanism to support the Company's critical infrastructure projects as an interim measure while a more fully developed and vetted K-bar formula can be developed (DOER Brief at 15-16; DOER Reply Brief at 4-5). DOER argues that the creation of multiple capital trackers and recovery mechanisms for the Company's investments is a non-sustainable practice (DOER Brief at 15). Rather, DOER contends that a formulaic approach with built-in cost containment mechanisms and performance incentives is an appropriate long-term solution to increasing capital investment demand (DOER Brief at 16-17).

Finally, DOER argues that the Department should modify the Company's initial proposed PBR to reduce rate shock for customers (DOER Brief at 17). In this regard, DOER supports the Company's revised proposal to cap the inflation factor in its PBR formula at five percent (DOER Brief at 17-18).

3. Acadia Center

Acadia Center argues that the Department should reject the Company's proposed ten-year PBR term and instead approve a five-year term, as this structure is more appropriate in light of the expected substantial capital investments over the next five years (Acadia Center Brief at 10-11, citing D.P.U. 20-120; Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 18-150 (2019)). Further, Acadia Center contends that the Company has acknowledged the significant risks involved with a ten-year PBR plan, including unprecedented investment in climate adaptation and electrification (Acadia Center Brief at 12).

Acadia Center also argues that NSTAR Electric's current PBR plan, and specifically the negative X factor, has resulted in a financial windfall for the Company (Acadia Center Brief at 13). Acadia Center contends that the negative X factor is nationally unprecedented and reflects declining performance, which, in turn, provides little incentive for the Company to address its productivity issues (Acadia Center Brief at 13-14). Acadia Center asserts that utility compensation should be distinctively linked to measurable performance outcomes that benefit customers, and, therefore, the Department should reject a negative X factor in this proceeding (Acadia Center Brief at 14).

4. Cape Light Compact

Cape Light Compact argues that a ten-year PBR plan term would be too long given the likelihood of significant change in the electric industry in that timeframe (e.g., advanced metering, electrification) and the need to address other issues in the Company's next base distribution rate case (e.g., eliminating full revenue decoupling, continuing consolidation of EMA and WMA rates) (CLC Brief at 38; CLC Reply Brief at 12). Cape Light Compact also contends that NSTAR Electric's proposal to file "rate schedules" at the five-year point is unclear, as the Company does not specify what that filing would entail (CLC Brief at 38, citing Exhs. DPU 5-1; CLF 1-1). In addition, Cape Light Compact supports the Attorney General's recommendation for an all-in capital tracker (CLC Reply Brief at 10-11). According to Cape Light Compact, an all-in capital tracker offers the most balanced approach for ratepayers and the Company, allows appropriate regulatory review and cost recovery, provides a more straightforward, easily understood alternative to PBR, and is administratively efficient (CLC Reply Brief at 10-11, citing Attorney General Brief at 8-9).

5. CLF[25]

CLF argues that the Company's proposed ten-year PBR plan term is unreasonably long and may prohibit necessary review in the future (CLF Brief at 5). Thus, CLF contends that the Company should conduct additional review and cost analysis to provide more accurate depictions of electrification costs over the next several years and should seek Department approval of moderate changes to base distribution rates as they become necessary (CLF Brief at 5). Further, CLF argues that the Company's proposed PBR plan is not in the public interest as it fails to limit recovery to reasonable costs and is insufficient to meet the ratemaking principles of fairness and equity (CLF Brief at 12-13). Accordingly, CLF recommends that the Department deny the Company's proposed PBR plan (CLF Brief at 5). Alternatively, if the Department approves a PBR plan for the Company, CLF recommends certain modifications (CFL Brief at 5). In particular, CLF argues that the Department should not approve rate increases associated with NSTAR Electric's critical infrastructure projects without first reviewing the specific details of the proposals, requiring the Company to engage

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[25] CLF's initial brief is, at times, difficult to understand. CLF appears to use the term "petition" interchangeably to describe both the Company's request for a base distribution rate increase and request for approval of a PBR plan. Our summary of CLF's arguments, as they pertain to the proposed PBR plan, relies on some assumptions as to which "petition" CLF refers. In future proceedings, a more clearly written brief would facilitate our consideration of the arguments.

with the community before filing for siting approval, and ensuring equitable distribution of burdens and benefits associated with the projects (CLF Brief at 15-16; CLF Letter in Lieu of Reply Brief at 1).

6. TEC and PowerOptions

TEC and PowerOptions argue that the Department should reject the Company's proposed ten-year PBR plan term and instead approve a five-year term that is inclusive of all capital projects (TEC/PowerOptions Brief at 13-14; TEC/PowerOptions Reply Brief at 8). TEC and PowerOptions contend that the historic pace of change currently occurring in the electric industry requires that the Department not relinquish its ability to supervise the Company for a period of ten years (TEC/PowerOptions Brief at 14). Further, TEC and PowerOptions assert that a five-year term is more congruous with the recent Department-approved PBR plans approved for National Grid's electric and gas operating companies in Massachusetts (TEC/PowerOptions Brief at 14).

TEC and PowerOptions also argue that the Company's proposed PBR plan should not include a separate cost recovery factor for the critical infrastructure projects or exogenous cost recovery for Enterprise IT projects, as both categories of projects represent core distribution investments (TEC/PowerOptions Brief at 13; TEC/PowerOptions Reply Brief at 8-9). Further, TEC and PowerOptions contend that the costs associated with the critical infrastructure projects could be evaluated in a base distribution rate proceeding at the end of a five-year PBR plan term, which also would allow for a timely review of mature substation capacity projects (TEC/PowerOptions Reply Brief at 8). Additionally, TEC and

PowerOptions claim that the proposed exogenous cost treatment for Enterprise IT expenses is incongruous with the premises of PBR plans, as, under a PBR plan, the Company is granted annual rate increases to allow for business operations (TEC/PowerOptions Reply Brief at 8). Moreover, TEC and PowerOptions assert that most software is purchased at the service company level, and that the Company's concerns surrounding IT expenses can be mitigated by a five-year PBR plan term (TEC/PowerOptions Reply Brief at 8-9).

TEC and PowerOptions also argue against the proposed roll-in of 2022 capital additions and assert that these additions are outside the scope of review for this proceeding (TEC/PowerOptions Brief at 15). Finally, TEC and PowerOptions support the proposed five-percent inflation cap, including allowing the Company to file a base distribution rate case if earnings fall more than 400 basis points below the ROE authorized in the instant proceeding (TEC/PowerOptions Reply Brief at 9).

7. UMass

UMass argues that the Company's proposed PBR plan should be denied until a better array of metrics is developed (UMass Brief at 47). UMass does not raise any specific arguments on brief about the components of the proposed PBR plan.

8. Company

a. Introduction

The Company asserts that its proposal to continue with a PBR plan is designed to provide funding for needed infrastructure projects and increasing operating expenses between base distribution rate cases (Company Brief at 14). The Company contends that its existing

PBR plan has proven that it is an innovative mechanism that is effective in promoting rigorous cost control, while also enabling investment in emerging technologies that will enhance reliability for residential and business customers and help Massachusetts meet its ambitious clean-energy goals, including the substantial investment in distribution automation, electric vehicle ("EV") infrastructure, and other clean energy capabilities (Company Brief at 14, citing Exh. ES-CAH/DPH-1, at 62).

According to NSTAR Electric, the existing PBR plan challenged the Company to find better, more innovative ways to achieve cost reductions while still providing customers with safe and reliable service, which benefits the overall system, whether in relation to the integration of distributed generation ("DG"), energy storage, or other electrification purposes (Company Brief at 14, citing Exh. ES-CAH/DPH-1, at 62). The Company asserts that during this time, it made total gross investments of over $2 billion in rate base, worked to contain its O&M expenses, did not over earn its authorized ROE, and provided benefits to customers through an overall lower impact to rates than what was forecasted in D.P.U. 17-05 (Company Brief at 19-21, citing Exhs. ES-CAH/DPH-1, at 19-22, 25-27; DPU 25-16). The Company asserts that the PBR construct was also effective at maintaining a level of rate stability and predictability by avoiding relatively larger rate changes that typically accompany a base distribution rate proceeding (Company Brief at 14, citing Exh. ES-CAH/DPH-1, at 62). For these reasons, the Company proposes to continue operating under a PBR Plan with a longer, ten-year term (Company Brief at 14).

NSTAR Electric reiterates its request for Department approval of the Company's initially proposed PBR plan (Company Brief at 15). The Company, however, also asserts that, in the alternative, the Department may allow a ten-year PBR plan with the several revisions proposed during the proceeding (Company Brief at 15, 53-57, citing Exhs. ES-PBR-Rebuttal-1, at 45-46; DPU 63-3). NSTAR Electric contends that its revised PBR plan has several benefits for customers by smoothing the impact of the January 1, 2024, adjustment and maintaining stability over the ten-year term of the PBR plan, while allowing the Company more adequate capital cost recovery (Company Brief at 15, citing RR-AG-7; RR-DPU-43, Tr. 12, at 1260).

b. PBR Plan Components[26]

NSTAR Electric argues that its requested PBR plan term is appropriate because it will create stronger incentives for the Company to maximize opportunities associated with electrification and grid modernization (Company Brief at 45, citing Exh. ES-PBR/PLAN-1, at 16). The Company rejects intervenor arguments that a ten-year PBR plan term is too long (Company Brief at 80-89). The Company argues that the revenue predictability from a ten-year PBR plan will aid its distribution system planning efforts and provide stronger efficiency incentives in doing so (Company Brief at 80). Further, the Company contends that

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[26] The Company summarized the various components of its initial PBR plan proposal and the revised proposal offered during the proceeding (Company Brief at 21-57). In the interest of administrative efficiency, in this section we focus on the components of the proposals challenged by the intervenors and the Company's response to the issues raised by the intervenors.

a ten-year term will allow resources that would have otherwise been devoted to base distribution rate case filings to be put toward meeting future challenges (Company Brief at 80-81). In addition, the Company asserts that a ten-year PBR plan term would provide the flexibility and incentives needed to meet the Commonwealth's clean energy objectives (Company Brief at 82). Moreover, NSTAR Electric contends that approval of a ten-year PBR plan term would not amount to pre-approval of large infrastructure projects or excuse the Company from regulatory review of the prudency of the costs (Company Brief at 85).

NSTAR Electric also expresses confidence in its ability to assume the risk of a ten-year PBR plan term and claims that but for the expiration of its current PBR plan, the Company would not have filed the instant base distribution rate case (Company Brief at 81). Further, the Company argues that because of its unique operating environment and future obligations and requirements, it is inappropriate to allow a five-year PBR plan term simply because that duration was approved for other utilities (Company Brief at 88-89). Finally, the Company submits that it provided a clear outline for its proposed mid-term filing to satisfy the statutory requirements in G.L. c. 164, § 94 (Company Brief at 81).

The Company next argues that contrary to the Attorney General's claims, the TFP study is robust, appropriately designed, and supports the initially proposed X factor of -1.45 percent (Company Brief at 72). The Company rejects the notion that the TFP study should not include costs that are recovered through reconciling mechanisms outside of base distribution rates (Company Brief at 72). The Company asserts that the TFP study is a measure of productivity, not cost recovery, and that the study measures the total cost of providing distribution service (Company Brief at 72-73). Further, the Company argues that the TFP study does not produce overstated results, and ultimately the difference between the TFP study in the instant proceeding and the TFP study performed for D.P.U. 17-05 is only four basis points, which indicates that the model is robust (Company Brief at 73-74). NSTAR Electric also contends that, contrary to Acadia Center's argument, a negative X factor is not indicative of underperformance, but rather is exogenous to the Company's performance, reflects the expected unit cost performance of an average firm in the industry, and indicates increasing capital needs among the industry while output declines or slows in the same period (Company Brief at 90). Additionally, the Company maintains that its current revenue deficiency is not due to imprudent business practices but instead due to unusually high storm costs, increased capital investments, increased enterprise IT costs, and the transfer of vegetation management costs to base distribution rates (Company Brief at 90).

NSTAR Electric argues that its initially proposed 15 basis-point (or 0.15 percent) consumer dividend is supported by Department precedent and two cost benchmarking studies performed by the Company's consultant (Company Brief at 37, citing Exh. ES-PBR/PLAN-1, at 38). The Company contends that the Department has previously found that benchmarking terms of three years apply equally to five- and ten-year PBR plan terms, and, as such, the Department should accept the use of a three-year period for benchmarking (Company Brief at 76). Thus, the Company asserts that it was not necessary to use a longer benchmarking term, as argued by the Attorney General (Company Brief at 76).

The Company also disagrees with the Attorney General's position regarding the proposed ROERA adjustment (Company Brief at 69-71). According to NSTAR Electric, the ROERA adjustment is necessary as the Company will be required to make large capital investments in the next ten years, and changes in capital markets do not presently qualify as exogenous events (Company Brief at 41, citing Exh. ES-CAH/DPH-1, at 76). Further, NSTAR Electric contends that the I-X formula will not appropriately compensate the Company for changes in capital market conditions, and that the risk of not being able to access capital markets is higher over a ten-year period (Company Brief at 42). In addition, the Company argues that it is inordinately affected by changes in capital market conditions as electric distribution is a capital-intensive industry, and financial risks are exacerbated by current inflation rates and the ensuing impact on debt and equity rates, which are not reflected in the TFP study (Company Brief at 42, 71).

Regarding the proposed exogenous cost provision, the Company disagrees with the Attorney General's contention that Enterprise IT costs should not be eligible for recovery (Company Brief at 78). The Company argues that it is becoming more cost-effective to utilize cloud computing, which results in more IT costs being incurred as expense rather than capital (Company Brief at 39, citing Exh. ES-CAH/DPH-1, at 86). Thus, the Company contends that it is necessary to treat these costs as exogenous under the PBR plan (Company Brief at 39). The Company asserts that if it does not incur these costs, as the Attorney General suggests, then there will be nothing to recover (Company Brief at 78). Further, the Company contends that it will have to demonstrate that any Enterprise IT costs sought for exogenous recovery are incremental to amounts provided in base distribution rates (Company Brief at 78).

Next, NSTAR Electric argues that to make the proposed ten-year PBR plan term feasible, the Company should be allowed to roll-in 2021 and 2022 capital investments (Company Brief at 53, citing Exh. ES-CAH/DPH-1, at 74-75). Further, the Company contends that its proposal is consistent with the Department's approval of a ten-year PBR plan term for NSTAR Gas (Company Brief at 87, citing D.P.U. 19-120, at 72). Finally, NSTAR Electric claims that TEC and PowerOptions have not provided any basis for deviating from this precedent or any evidence that the requested capital roll-ins would not be necessary for the Company's PBR plan (Company Brief at 87, citing TEC/PowerOptions Brief at 15). Based on these considerations, the Company asserts that the Department should allow the roll-in of 2022 capital additions if the ten-year PBR plan term is approved (Company Brief at 87).

The Company agrees with many of the Attorney General's proposed tariff changes, and contends they represent suggestions to directly incorporate definitions that are contained in other referenced tariffs (Company Brief at 79). The Company, however, does take issue with several of the Attorney General's recommendations (Company Brief at 79).

Finally, the Company rejects the Attorney General's recommended "all-in capital tracker" (Company Brief at 59). NSTAR Electric argues that, due to the magnitude of the prospective filing, an all-in capital tracker would be more administratively burdensome than the proposed PBR plan for the Company, Department, and relevant stakeholders (Company

Brief at 59-60, citing Exh. DPU 25-13). Further, the Company contends that an all-in capital tracker would create poor incentives by encouraging capital expenditure, and therefore, such a tracker is not compatible with the Department's efficiency goals (Company Brief at 61). In addition, the Company claims that an all-in capital tracker would lead to increased regulatory costs as more frequent base distribution rate cases would be needed to roll the additions into base distribution rates (Company Brief at 61). According to the Company, its K-bar proposal is a better option, as it does not result in dollar-for-dollar recovery and the PBR adjustments are automatic, leaving intact both cost control incentives and administrative efficiencies (Company Brief at 56-57, 60-61).

D. Analysis and Findings

1. Introduction

In the sections below, we review our ratemaking authority and conclude that, pursuant to G.L. c. 164, § 94, the Department may implement PBR as an adjustment to cost of service/rate of return regulation. Further, we discuss the factors that the Department has applied to review incentive regulation proposals. Finally, we review the Company's initially proposed PBR plan and the proposed revised plan, and we determine whether allowing a PBR plan is in the public interest and will result in just and reasonable rates.

2. Department Ratemaking Authority

Pursuant to G.L. c. 164, § 94, the Legislature has granted the Department extensive ratemaking authority over electric and gas distribution companies.[27] The Supreme Judicial Court has consistently found that the Department's authority to design and set rates is broad and substantial. See, e.g., Boston Real Estate Board v. Department of Public Utilities, 334 Mass. 477, 485 (1956). Because G.L. c. 164, § 94 authorizes the Department to regulate the rates, prices, and charges that electric and gas distribution companies may collect, this authority includes the power to implement revenue adjustment mechanisms such as a PBR. Boston Gas Company v. Department of Telecommunications and Energy, 436 Mass. 233, 234-235 (2002); see also G.L. c. 164, § 1E (authorizes Department to establish PBR for jurisdictional electric and gas companies).

The Department is not compelled to use any particular method to establish rates, provided that the end result is not confiscatory (i.e., deprives a distribution company of the opportunity to realize a fair and reasonable return on its investment). Boston Edison, 375 Mass. 1, 19. The Supreme Judicial Court has held that a basic principle of ratemaking is that "the department is free to select or reject a particular method as long as its choice does not have a confiscatory effect or is not otherwise illegal." American Hoechest Corporation v. Department of Public Utilities, 379 Mass. 408, 413 (1980), citing Massachusetts Electric Company v. Department of Public Utilities, 376 Mass. 294, 302 (1978).

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[27] Pursuant to G.L. c. 165, § 2, the Department's ratemaking authority under G.L. c. 164, § 94 also applies to water distribution companies.

In addition, G.L. c. 164, § 76, grants the Department broad supervision over electric and gas distribution companies. Under G.L. c. 164, § 76C, the Department has the authority to establish reasonable rules and regulations consistent with G.L. c. 164, as needed, to carry out its administration of jurisdictional companies in the public interest. D.P.U. 07-50-B at 26-27. See also Cambridge Electric Light Company v. Department of Public Utilities, 363 Mass. 474, 494-496 (1973).

Although the Department traditionally has relied on cost of service/rate of return regulation to establish just and reasonable rates, there are many variations and adjustments in the specific application of this model to individual utilities as circumstances differed across companies and across time. D.P.U. 07-50, at 8. Over the years, electric and gas distribution companies subject to the Department's jurisdiction have operated under PBR or PBR-like plans. See, e.g., D.P.U. 19-120, at 58; D.P.U. 18-150, at 47; D.P.U. 17-05, at 371-372; Bay State Gas Company, D.T.E. 05-27, at 382 (2005); Boston Gas Company, D.T.E. 03-40, at 471 (2003); The Berkshire Gas Company, D.T.E. 01-56, at 10 (2002; Massachusetts Electric Company/Eastern Edison Company, D.T.E. 99-47, at 4-14 (2000).

Consistent with the discussion above, the Department reaffirms that we may implement PBR as an alternative to cost of service/rate of return regulation under the broad ratemaking authority granted to us by the Legislature under G.L. c. 164, § 94. In addition, the Department validates the propriety of the continued use of PBR as a meaningful regulatory format.

3. Evaluation Criteria for PBR

The Department must approach the setting of rates and charges in a manner that: (1) meets our statutory obligations under G.L. c. 164, § 94, to ensure rates that are just and reasonable, not unjustly discriminatory, or unduly preferential; and (2) is consistent with long-standing ratemaking principles, including fairness, equity, and continuity. D.P.U. 07-50, at 10-11. Further, the Department must establish rates in a manner that balances a number of these key principles to reflect and address the practical circumstances attendant to any individual company's base distribution rate case. D.P.U. 07-50-A at 28. The Department has implemented PBR plans or PBR-like mechanisms on a finding that such regulatory methods would better satisfy our public policy goals and statutory obligations. See, e.g., Boston Gas Company, D.P.U. 96-50 (Phase I) at 261 (1996); D.P.U. 94-158, at 42-43; New England Telephone and Telegraph Company, D.P.U. 94-50, at 139 (1995).

As part of our investigation of incentive ratemaking, the Department examined the criteria to evaluate PBR proposals for electric and gas distribution companies. D.P.U. 94-158, at 52-66. The Department found that, because incentive regulation acts as an alternative to traditional cost of service regulation, incentive proposals would be subject to the standard of review established by G.L. c. 164, § 94, which requires that rates be just and reasonable. D.P.U. 94-158, at 52; Attorney General v. Department of Telecommunications and Energy, 438 Mass. 256, n.13 (2002) (in determining the propriety of rates under G.L. c. 164, § 94, the Department must find that the rates are just and reasonable). Further, the Department determined that a petitioner seeking approval of an incentive regulation proposal like PBR is required to demonstrate that its approach is more likely than current regulation to advance the Department's traditional goals of safe, reliable, and least-cost energy service and to promote the objectives of economic efficiency, cost control, lower rates, and reduced administrative burden in regulation. D.P.U. 94-158, at 57. Finally, a well-designed incentive mechanism should provide utilities with greater incentives to reduce costs than currently exist under traditional cost of service regulation and should result in benefits to customers that are greater than would be present under current regulation. D.P.U. 94-158, at 57.

In addition to these criteria, the Department established a number of additional factors that it would weigh in evaluating incentive proposals. D.P.U. 94-158, at 57. These factors provide that a well-designed incentive proposal should: (1) comply with Department regulations, unless accompanied by a request for a specific waiver; (2) be designed to serve as a vehicle to a more competitive environment and to improve the provision of monopoly services; (3) not result in reductions of safety, service reliability, or existing standards of customer service; (4) not focus excessively on cost recovery issues; (5) focus on comprehensive results; (6) be designed to achieve specific, measurable results; and (7) provide a more efficient regulatory approach, thus reducing regulatory and administrative costs. D.P.U. 94-158, at 58-64.

4. Rationale for PBR

There is a fundamental evolution taking place in the way electricity is produced and consumed in Massachusetts. This evolution has been driven, in large part, by a number of legislative and administration policy initiatives designed to address climate change and to foster a clean energy economy through the promotion of energy efficiency, demand response, and DG, and the procurement of long-term contracts for renewable energy. See, e.g., 2022 Clean Energy Act; An Act Creating a Next-Generation Roadmap for Massachusetts Climate Policy, St. 2021, c. 8 ("2021 Climate Act"); The Massachusetts 2050 Decarbonization Roadmap[28]; An Act Relative To Green Communities, St. 2008, c. 169 ("Green Communities Act"); An Act Establishing the Global Warming Solutions Act, St. 2008, c. 298; An Act Relative to Competitively Priced Electricity in the Commonwealth, St. 2012, c. 209, § 36; Green Communities Expansion Act, § 83A; Executive Order No. 569: Establishing an Integrated Climate Change Strategy for the Commonwealth (September 16, 2016). To varying degrees, this evolution is changing the operating environment for EDCs in Massachusetts.

As described above, the Company proposes to continue operating under a PBR plan for the next ten years (Exhs. ES-CAH/DPH-1, at 13, 63, 93; ES-PBR/PLAN-1, at 13; ES-PBR-Rebuttal-1, at 45). In addition to the arguments set forth above in Section IV.C.8, NSTAR Electric states that its operating dynamics will continue to evolve bringing even greater technological complexity, larger investment requirements, and a persistent need to

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[28] The Massachusetts 2050 Decarbonization Roadmap defines eight decarbonization pathways, and the "All Options" pathway is the benchmark compliant decarbonization pathway using midpoint assumptions across most technical parameters (Massachusetts 2050 Decarbonization Roadmap at 15, found at: https://www.mass.gov/doc/ma-2050-decarbonization-roadmap/download).

find and develop skilled personnel to manage the Company and meet the expectations of customers on a day-to-day basis (Exh. ES-CAH/DPH-1, at 33). In particular, NSTAR Electric states that its fundamental challenge is a pressing need to complete system upgrades and improvements to meet growing customer expectations of reliability and resiliency; increase system demands in anticipation of electrification; and integrate DG, all in the face of stagnant sales volumes (Exh. ES-PBR-Rebuttal-1, at 5). Further, the Company notes that it is planning for the future with particular focus on building capabilities to meet future service requirements in an electrified environment (Exhs. ES-CAH/DPH-1, at 33; ES-ENG-1, at 10-21; ES-PBR-Rebuttal-1, at 5). According to NSTAR Electric, PBR is a critical factor in the Company's operating environment because it provides the Company with the latitude to focus on operations and to meet expectations, while providing the critical resources necessary to "make ends meet" (Exh. ES-CAH/DPH-1, at 33-34). In addition, the Company submits that PBR creates broad-based incentives for cost control because it applies across the entire utility operation and supports both capital investment and O&M costs (Exh. ES-PBR-Rebuttal-1, at 12). Further, NSTAR Electric expects that without a PBR plan, the Company likely would file up to four base distribution rate cases through the end of 2031 to keep up with the substantial capital outlay expected over a ten-year period (Exh. ES-PBR-Rebuttal-1, at 48).

As discussed above in Section IV.C, several intervenors argue against the Company's PBR plan proposals as not in the public interest, not tied to achievement of any specific, measurable results, or otherwise not appropriate for approval. Further, several of the intervenors recommend changes to the Company's proposals, should the Department approve a PBR plan.

The Department finds that the Company has demonstrated that continuing its PBR plan is an appropriate alternative to traditional cost of service/rate of return ratemaking. During the current PBR term, approved in D.P.U. 17-05, the Company made over $2 billion in capital investments in new business and peak load growth, basic business requirements, and replacement of aging infrastructure (Exh. ES-CAH/DPH-1, at 19-25). In particular, the Company installed, expanded, or upgraded its infrastructure to accommodate electric demand growth and installed new or replaced old distribution equipment in an effort to reduce the number of outages experienced by customers. (Exh. ES-CAH/DPH-1, at 20). Further, during the current PBR term, the Company instituted a variety of cost containment initiatives, including implementation of robotic process automation; using data analytics to streamline and automate reliability reporting and other work processes; fleet standardization; contract renegotiations; and leveraging of supply chain partnerships and use of contractors of choice for engineering work (Exh. ES-CAH/DPH-1, at 18-19, 25-26). In addition, we find that NSTAR Electric has demonstrated that the current PBR plan has been effective in maintaining rate stability, delivery price predictability and avoiding relatively larger rate changes (Exhs. ES-CAH/DPH-1, at 18-19, 62; DPU 25-16).

The Department finds that allowing NSTAR Electric to continue to operate under a PBR plan will provide the Company more flexibility to address an evolving operating environment, such as changes in energy and climate policy; emerging technologies;

challenges in hiring, training, and retaining skilled personnel; replacing, upgrading, and maintaining aging infrastructure; increasing frequency and intensity of storms; and higher customer expectations (Exhs. ES-CAH/DPH-1, at 31-61; ES-PBR/PLAN-1, at 15-16, 31-34; ES-PBR-Rebuttal-1, at 23-32). Further, as part of the PBR plan, the Company has committed to refraining from filing rate schedules to put new base distribution rates into effect during the PBR plan term (Exh. ES-CAH/DPH-1, at 68 n.10, 86, 92). The Department accepts that this stay-out provision will result in diminished administrative burden and in efficiencies (Exh. ES-CAH/DPH-1, at 59).

In addition, the Department finds that, in this instance, a PBR plan is better suited to satisfy the Department's public policy goals and statutory obligations than the Attorney General's proposed all-in capital tracker. In particular, the Department finds an all-in tracker that provides dollar-for-dollar recovery for investments is inconsistent with the principle of spending efficiency that a PBR plan is intended to encourage. Further, as discussed below, the Department adopts a K-bar approach to capital spending within the approved PBR plan. The flexibility and revenue predictability provided by the K-bar approach will allow the Company to address a variety of future expenses without additional cost recovery filings. The K-bar approach is formulaic in nature, which provides for simplicity and a measure of administrative ease during the annual PBR filing review (Exh. DPU 35-5; RR-DPU-12, at 3). In contrast, the Attorney General's recommended all-in capital tracker would require annual review of all capital investments, which may be unduly burdensome and difficult to complete in a timely manner.

Finally, as discussed in Section V.D below, the Department has approved a variety of PBR-specific metrics to measure the Company's performance and the full range of benefits that will accrue under the PBR plan with the goal of assuring customers and stakeholders that standards of service are maintained or improved, and that meeting clean energy goals are advanced during the PBR term. As such, we are not persuaded by the Attorney General's argument that the Company's proposed PBR plan is overly focused on cost recovery.

Below, the Department addresses the specific components of the PBR plan and whether the PBR mechanism appropriately balances ratepayer and shareholder risk, is in the public interest, and will result in just and reasonable rates.

5. PBR Plan Components

a. PBR Plan Term

The Company initially proposed a ten-year PBR term with a mid-term filing of rate schedules at the five-year mark (Exhs. ES-CAH/DPH-1, at 13, 93; ES-PBR/PLAN-1, at 13). In its rebuttal testimony, the Company revised certain components of its proposed PBR plan. In offering some revisions to its PBR plan during the course of the proceeding, the Company, however, did not revise the term of PBR plan and proposed to maintain the ten-year term (Exh. ES-PBR-Rebuttal-1, at 45). The ten-year PBR term would commence on January 1, 2023, and expire on December 31, 2032, during which there would be nine annual PBR mechanism adjustments, taking effect each January 1, beginning in 2024 (Exh. ES-CAH/DPH-1, at 64-65, 93). In conjunction with the PBR term, NSTAR Electric proposed a stay-out provision whereby the Company may file a base distribution rate case during the PBR term that would result in new base distribution rates going into effect no earlier than January 1, 2033 (Exh. ES-CAH/DPH-1, at 68 n.10, 86, 92).

The Department has found that a well-designed PBR plan should be of sufficient duration to give the plan enough time to achieve its goals and to provide utilities with the appropriate economic incentives and certainty to follow through with medium- and long-term strategic business decisions. D.P.U. 96-50 (Phase I) at 320; D.P.U. 94-158, at 66; D.P.U. 94-50, at 272. In addition, the Department has stated that one benefit of incentive regulation is a reduction in regulatory and administrative costs. D.P.U. 19-120, at 63; D.P.U. 18-150, at 53; D.P.U. 17-05, at 402; D.P.U. 96-50 (Phase I) at 320; D.P.U. 94-158, at 64.

Previous PBR plans approved by the Department have had terms of five and ten years. See, e.g., D.P.U. 20-120, at 72 (five years); D.P.U. 19-120, at 65 (ten years); D.P.U. 18-150, at 56 (five years); D.P.U. 17-05, at 404 (five years); D.T.E 05-27, at 399 (ten years); D.T.E. 03-40, at 495-496 (ten years); D.T.E. 01-56, at 10 (ten years); D.P.U. 96-50 (Phase I) at 320 (five years). The Department finds that the circumstances presented in the instant case do not support a PBR plan term of ten years. Instead, the Department approves a PBR plan term of five years with the possibility of a five-year extension, as discussed further below.

As noted above, the Company intends to undertake substantial capital investments over the next five- to ten-year period, such as the critical infrastructure projects and other investments necessary to comply with legislative and administration policy initiatives designed to address climate change and to foster a clean energy economy (Exhs. ES-CAH/DPH-1, at 77-82; ES-PBR-Rebuttal-1, at 39-40; ES-ENG-1, at 7-8; ES-ENG-3). Due to these and other anticipated expenditures, the Department is hesitant to allow annual formulaic revenue adjustments over a longer term that likely will not align with capital investment requirements.

The Department reaffirms that a longer PBR term generally coincides with stronger economic incentives, a longer strategic planning horizon, and additional time to accrue administrative efficiencies, supporting the policy that a PBR term of up to ten years, under the right circumstances, is preferrable. D.P.U. 20-120, at 72. Our finding here of a five-year PBR term is grounded in the specific circumstances presented in this case. Further, the Department concludes that a five-year PBR term will allow for the resources and flexibility necessary for the Company to adjust its operations and investments efficiently, and, in turn, best ensures ratepayer benefits of increased operational efficiencies and improved service, and the opportunity for avoided administrative costs. In addition, a stay-out provision provides the important benefit to ratepayers of ensuring strong incentives for cost containment under the PBR. D.P.U. 19-120, at 65; D.P.U. 18-150, at 55; D.P.U. 17-05, at 403. Accordingly, the Department adopts a stay-out provision in conjunction with the five-year term.

In recognition of the Company's forecasted spending, and given our preference for longer term PBR plans, the Department finds it reasonable and appropriate to allow the Company, prior to the expiration of the five-year PBR plan term, to file a request to continue the PBR plan term for another five years. This request must be filed with the Department no earlier than nine months and no later than six months prior to the termination of the initial PBR plan term. In the filing, the Company must demonstrate that it is in the public interest to continue the current PBR mechanism for another five years. NSTAR Electric must include testimony and supporting revenue requirement schedules that show the anticipated revenue deficiency would be if the Company were to file a base distribution rate case. The Company's filing also shall include a performance metrics proposal, as discussed in Section V.D.3 below. The Department will investigate the request and provide the Attorney General and other interested stakeholders an opportunity to comment on the filing. Balancing the best interests of ratepayers with the financial integrity of the Company, if the Department determines that continuing the PBR term is in the public best interest, the Company may continue the PBR plan for an additional five-year period, with no changes to the base distribution rates approved in the instant proceeding. If the Department determines that continuing the PBR plan term is not in the public interest, the stay-out provision shall be extended approximately one year, and the PBR plan approved in the instant case shall remain in place for one additional year to allow the Company sufficient time to prepare a base distribution rate filing.[29]

b. Productivity Offset

As noted above, the Company initially proposed an X factor of -1.45 percent (Exh. ES-PBR/TFP-1, at 24). In its rebuttal testimony, the Company proposed to reduce the

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[29] The Department may initiate procedural discussions with the Company and relevant stakeholders regarding the timing of the subsequent base distribution rate case filing.

X factor to zero, as recommended by the Attorney General (Exh. ES-PBR-Rebuttal-1, at 44-45, citing Exhs. AG-DED-PBR-1, at 3, 58; AG-DPL-1, at 12). The Department finds that the Company's revised proposed X factor of zero is appropriate, particularly when considering the other changes and modifications to the PBR plan approved herein. As such, we approve an X factor of zero.

c. Inflation Index and Floor

As noted above, the Company initially proposed to calculate the price inflation index based on the GDP-PI, with an inflation "floor" equivalent to the X factor of -1.45 percent so that a negative PBR adjustment would not occur (Exh. ES-CAH/DPH-1, at 68). In its rebuttal testimony, NSTAR Electric proposed to cap the inflation index at five percent, and the Company stated that it would "make sense" to have the opportunity file a base distribution rate case if reported earnings fall more than 400 basis points below the ROE authorized in the instant proceeding (Exhs. ES-PBR-Rebuttal-1, at 45; DPU 35-1).

In D.P.U. 94-50, at 141, the Department found that the GDP-PI is the most accurate and relevant measure of output price changes for the bundle of goods and services whose TFP growth is measured by the Bureau of Labor Statistics. In addition, the Department found that GDP-PI is: (1) readily available; (2) more stable than other inflation measures; and (3) maintained on a timely basis. D.P.U. 94-50, at 141. In the instant proceeding, no party disputes that the GDP-PI is an appropriate measure for inflation in a revenue cap PBR formula. The Department finds that the Company's use of GDP-PI as an inflation index in the PBR formula is reasonable and approves its use.

As described above, the Company has proposed to include an inflation cap of five percent in the revenue cap formula, meaning that if inflation rises above five percent, the Company will set the inflation component of the PBR formula at five percent (Exhs. ES-PBR-Rebuttal-1, at 45; DPU 35-1). The remaining parties do not oppose the proposed inflation index cap (Attorney General Brief at 65; DOER Brief at 17-18; TEC/PowerOptions Reply Brief at 9). Accordingly, the Department approves the Company's proposed inflation index cap of five percent. The Department, however, disallows including a provision in the Company's proposed PBR plan that would allow the Company the opportunity to file a base distribution rate case if reported earnings fall more than 400 basis points below the ROE authorized in this proceeding. The Department is not persuaded that, absent other extenuating circumstances, such a situation warrants terminating the PBR plan and the associated stay-out commitment.

Finally, the Company proposed an inflation floor equivalent to the X factor of -1.45 percent so that a negative PBR adjustment would not occur (Exh. ES-CAH/DPH-1, at 68). In support of this proposal, the Company stated that its cost of service would never decline, even in a deflationary period (Exh. ES-CAH/DPH-1, at 68). While the Company has not substantiated this claim, we, nevertheless, find that an inflation floor of zero, to correspond with the approved X factor, is a reasonable component of the PBR mechanism, particularly when coupled with the inflation index cap approved above. Accordingly, the Department approves an inflation floor of zero for the Company.

d. Consumer Dividend

The consumer dividend is intended to reflect expected future gains in productivity because of the move from cost-of-service ratemaking to incentive regulation. D.P.U. 96-50 (Phase I) at 165-166, 280. As a deduction to the PBR adjustment, the consumer dividend is designed to share these productivity gains with ratepayers (Exhs. ES-CAH/DPH-1, at 73; ES-PBR/PLAN-1, at 37). The Department has found that a consumer dividend represents an explicit, tangible ratepayer benefit. D.P.U. 18-150, at 60-61; D.P.U. 17-05, at 395.

As discussed above, the Company initially proposed to include a consumer dividend of 15 basis points, or 0.15 percent, when inflation, as calculated in the proposed PBR formula, exceeds two percent (Exhs. ES-CAH/DPH-1, at 72; ES-PBR/PLAN-1, at 38). In its rebuttal testimony, the Company proposed to raise the consumer dividend to 25 basis points, or 0.25 percent, when inflation exceeds two percent (Exh. ES-PBR-Rebuttal-1, at 45). The Department finds that the Company's revised proposed consumer dividend is appropriate, particularly when considering the other changes and modifications to the PBR plan approved herein. As such, we approve the Company's revised consumer dividend of 0.25 percent when inflation exceeds two percent.

e. Post-Test-Year Capital Additions

NSTAR Electric asserts that over the next several years the Company anticipates making significant capital additions to improve the resiliency of the distribution system and to ensure safe and reliable service as the Commonwealth pursues its electrification objectives (Exhs. ES-CAH/DPH-1, at 31-61; ES-PBR/PLAN-1, at 15-16, 31-34; ES-PBR-Rebuttal-1, at 23-32). To address its prospective capital investments, the Company initially proposed to include post-test-year capital additions (i.e., 2021 and 2022 capital additions) in base distribution rates at two different intervals during the term of the proposed PBR plan and proposed to recover future critical infrastructure projects investments through the PBR mechanism (Exh. ES-CAH/DPH-1, at 74-75). In its rebuttal testimony, the Company proposed to eliminate the roll-in of the 2022 calendar-year capital additions from the first annual PBR plan filing and to eliminate its proposed rate treatment of future critical infrastructure projects (Exh. ES-PBR-Rebuttal-1, at 45). Instead, the Company proposed, as part of the revised PBR formula, a K-bar adjustment that would allow additional revenues to be collected through the PBR adjustments, beginning January 1, 2024, to provide additional funding for capital investments (Exhs. ES-PBR-Rebuttal-1, at 45; DPU 63-3 & Atts.; RR-DPU-12 & Atts.).

The Department recognizes that, during the PBR term, NSTAR Electric will need flexibility to address the evolving energy and climate policies governing EDCs, as well as to maintain aging infrastructure and enhance resiliency to address the impacts of climate change (Exhs. ES-CAH/DPH-1, at 31-61; ES-PBR/PLAN-1, at 15-16, 31-34; ES-PBR-Rebuttal-1, at 23-32). To address these issues and keep pace with the Commonwealth’s growing electrification needs and ambitious climate targets, the Company likely will need significant capital investments to develop a dynamic and modern distribution network. The Department anticipates that the Company may identify several capital projects to achieve these objectives during the development of its electric sector modernization plans pursuant to G.L. c. 164,

§ 92B. The Department recognizes that required investments will go beyond the Company's grid modernization proposals approved in Second Grid Modernization Plans, D.P.U. 21-80-B/D.P.U. 21-81-B/D.P.U. 21-82-B (November 30, 2022). The Department also finds that any capital investment program must encourage prudent investments while maintaining efficiencies and appropriate cost control measures. Further, while capital spending will be critical to achieve the Commonwealth's growing electrification needs and ambitious climate targets, a multi-year rate plan should have reasonable and predictable rate impacts for distribution customers, especially given the volatility of deregulated energy supply. Based on these considerations, the Department finds that the K-bar approach aligns more closely with the Company's objectives and needs than allowing a roll-in of the 2022 capital investments and the implementation of a separate recovery factor for critical infrastructure projects; therefore, and subject to the modifications below, the Department approves the incorporation of the K-bar in the Company's PBR mechanism.

The Department has reviewed both a fixed historical average and annual rolling-average K-bar approach (RR-DPU-12 & Atts.; RR-DPU-43 & Atts.; RR-DPU-44, Att.). For the reasons discussed below, the Department finds that implementing a rolling-average K-bar balances providing a reasonable level of funding for capital improvements while protecting ratepayers from rate increases that have no corresponding benefits. A fixed historical-average-based K-bar would provide the Company with a predictable level of funding each year of the PBR term regardless of the Company's actual capital investments. While the Department fully expects that NSTAR Electric will pursue system improvements annually, we acknowledge that large-scale capital projects may be delayed for reasons beyond the Company's control, including difficulty in obtaining permitting and/or engineering studies (Exh. ES-CAH/DPH-1, at 81-82). Historically, ratepayers have been financially protected from delays in capital spending due to regulatory lag. Distribution companies generally may not recover costs associated with capital improvements until after the Department completes a prudency review and determines that the capital investments are used and useful to customers. D.P.U. 20-120, at 155; D.P.U. 19-120, at 161-162; D.P.U. 17-05, at 85. The Department is concerned that using a fixed historical average to determine the increase in capital costs could expose customers to rate increases with no corresponding benefit if the Company fails to place projects into service in a timely manner. Thus, as we evaluate the design of the K-bar, the Department is mindful of balancing the Company's capital needs with the important consideration of the level of annual rate adjustments for customers. Based on these considerations, we find that the annual rolling-average K-bar provides an appropriate incentive for the Company to undertake necessary capital projects to meet its system needs and to adequately address relevant environmental and equity issues, as well as provides the flexibility required to adjust to project cost changes and to complete projects in a timely manner (Exhs. ES-CAH/DPH-1, at 31-61, 78-82; ES-PBR/PLAN-1, at 15-16, 31-34; ES-PBR-Rebuttal-1, at 23-32; RR-DPU-43, at 6-7).

Further, while the Department finds that an annual rolling-average K-bar provides ratepayers protection from annual rate increases without associated capital investments, the

Department also finds it reasonable and appropriate to protect customers from substantial rate increases in the event that the Company makes significant capital investments in a single year without a full prudency review (see RR-DPU-43, Att. (g); RR-DPU-44). Accordingly, the Department will limit the amount of capital improvements that may be automatically included in the annual K-bar adjustment. Specifically, the Department allows the Company an annual capital spending constraint of up to ten percent from the annual capital spending forecasted in this proceeding ("Forecasted Budget") (Exh. AG 1-18, Att. (Supp.); RR-DPU-43, Att. (d)).[30] As noted above, we recognize the challenges in accurately forecasting capital spending, as well as the potential impacts on future capital spending from recent and anticipated changes in energy and climate policy. As such, the Department finds it appropriate to allow a modest amount of flexibility from the Company's Forecasted Budget in setting the expenditure restraint.

Beginning with the annual PBR adjustment effective January 1, 2024, the Company's actual capital costs[31] for the calendar year prior to the year of the annual PBR plan filing, will be allowed for inclusion in the calculation of the K-bar average capital cost to the extent

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[30] The Forecasted Budget shall exclude capital projects that are eligible for recovery though rate mechanisms outside of base distribution rates (i.e., solar investments, meter-related capital as discussed in Section XV.C.2 below, and grid modernization investments).

[31] Actual capital costs shall exclude capital projects that are eligible for recovery though rate mechanisms outside of base distribution rates (i.e., solar investments, meter-related capital as discussed in Section XV.C.2 below, and grid modernization investments).

that the actual capital costs do not exceed the Forecasted Budget by more than ten percent, with no prudence review necessary at that time. Rate base included in the revenue requirement approved by the Department in this proceeding shall be used in the K-bar calculations. The K-bar formula will calculate revenue support for the Company using the approved rate base associated with capital additions to determine the annual revenue support available in the respective PBR year. To the extent that the actual capital costs in the prior year, in aggregate, exceed the Forecasted Budget by more than ten percent, then the K-bar allowance shall be capped at the ten-percent variance[32] from the Forecasted Budget, by excluding the variance from the K-bar calculation (Exh. AG 1-18, Att. (Supp.); RR-DPU-43, Att. (d)). Projects with the lowest costs will be eligible for inclusion in the annual K-bar adjustment up to the ten-percent cap. The Department finds that this approach is fair to the interests of both ratepayers and to the Company, is administratively efficient, and will avoid the burdensome review of an annual capital tracker mechanism.[33]

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[32] To determine the capital projects that exceed the ten-percent cap compared to the Forecasted Budget, the Company shall sum the actual capital costs from the prior year from least expensive to most expensive, for informational purposes. Based on this ranking, the Department may review the reasons for the budget overrun, and, if appropriate after notice, investigate prudence.

[33] The Department notes that the approved K-bar relies on accurate forecasted capital spending by the Company. In this regard, the Department places NSTAR Electric on notice that we may investigate the Company's capital spending if the Department concludes that the Company inappropriately over-estimated its Forecasted Budget and is lagging too far behind on investing into the distribution system. Further, the Department may investigate the prudency of any capital investment project included in the K-bar at any time and make any adjustment necessary if Company expenditures are determined to be imprudent.

In its 2023 PBR adjustment filing, the Company shall calculate the K-bar adjustment for effect January 1, 2024 using the five-year average of actual plant additions placed in service from 2018 through 2022[34] with the 2022 and 2023 bridge years both calculated using the five-year average of actual plant additions placed in service from 2017 through 2021 and carried forward to January 1, 2024, using the I-X formula in the PBR mechanism approved in the instant proceeding (RR-DPU-43, at 5-7 & Att. (d) at 4, line 25; at 7, lines 20, 28). The K-bar adjustment for effect January 1, 2025, will calculate the K-bar using the five-year average of plant additions placed in service from 2019 through 2023 (RR-DPU-43, at 5). The PBR adjustment for effect January 1, 2026, will calculate the K-bar using the five-year average of plant additions placed in service from 2020 through 2024 (RR-DPU-43, at 5). The five-year average will be updated in the same manner for each subsequent year that the K-bar remains in effect (RR-DPU-43, at 6-7). For the K-bar calculation, the deprecation rate shall be calculated by dividing the depreciation expense approved in the instant proceeding by the gross plant approved in the instant proceeding. The property tax rate shall be the property tax expense approved in the instant proceeding divided by the net utility plant in service approved in the instant proceeding. The return on rate base shall be the rate of return as shown in Schedule 5 below.

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[34] Given that plant additions placed in service in 2018 may be considered under the PBR plan approved in D.P.U. 17-05, we find it appropriate, and consistent with the Alberta approach, to use a five-year period that begins with 2018 and not with 2017 to derive the initial level of average spending (RR-DPU-12).

The Department finds that K-bar design approved above will bring several benefits to customers over the Company's proposal. First, using a rolling average will reduce the K-bar revenue if NSTAR Electric does not timely complete and place in-service projects prior to the next K-bar adjustment. The prospect of less K-bar revenue should incentivize the Company to complete projects in a timely manner and will limit customer exposure to costs associated only with projects actually completed. Further, the spending cap will benefit customers by limiting potential rate increases. Finally, a rolling K-bar is administratively efficient, as the Company no longer will need to request to roll-in 2022 capital additions through the PBR mechanism (Exh. ES-PBR-Rebuttal-1, at 45; RR-DPU-12, at 3).

The Department finds that the rolling-average K-bar mechanism will, given prudent management and decision making, provide the Company with adequate levels of revenue to support the capital investment that will be required in the coming years, while adhering to PBR principles. With the approval of the K-bar mechanism, the Department expects a reasonable level of stability in NSTAR Electric's capital project spending over the PBR plan term, as opposed to a disproportionate amount of spending in certain years, such as a proposed test year, should the Company choose to file a new base distribution rate case upon expiration of the PBR plan term (see Section IV.D.5.a above). The burden will be on the Company to manage expenditures and plan accordingly to keep pace with capital investment while developing and building a distribution network capable of supporting the Commonwealth's decarbonization goals. Finally, as part of its annual PBR filings, the Company shall file a forecast of its capital investment projects planned to go into service in the subsequent year, and the associated costs of those projects, for informational purposes. In addition, once available, the Company shall file, for informational purposes, its actual capital investment projects for the year of its annual PBR filing. For example, in its 2023 annual PBR filing, the Company shall file its forecasted 2024 planned capital investment projects. Then, in its 2024 annual PBR docket, the Company shall make an informational filing of its actual 2024 capital investment projects in the first quarter of 2025. These informational filings will assist the Department and stakeholders to monitor NSTAR Electric's progress on achieving the Commonwealth's 2050 climate targets, as well as increase transparency to stakeholders, provide a measure of accountability in the Company's decision making, and provide a check on the accuracy of the Company's projected capital spending.

f. ROERA Factor

As discussed above, the Company initially proposed to include in the PBR plan an ROERA mechanism to recover costs arising from changes in the capital markets during the proposed ten-year PBR term (Exhs. ES-CAH/DPH-1, at 76; ES-PBR/PLAN-1, at 8). The ROERA would be triggered, and a rate adjustment would take place, if the yield on ten-year Treasury bonds reaches 200 basis points above or below the yield in effect at the start of the PBR plan (Exh. ES-CAH/DPH-1, at 76-77). Given that the Department has approved a five-year PBR term, and in light of the other components of the PBR plan approved herein, we find that it is inappropriate to approve an ROERA adjustment.[35] We note that changes in the required cost of capital would be recovered, to a considerable extent, through the operation of the inflation index factor and the appropriate shifts in the Company's capital structure. Further, the Department also finds that the Company's ESM provides an additional layer of insulation from the kind of financial risk that the ROERA is designed to mitigate. Based on these considerations, the Department is not persuaded that the proposed ROERA is a necessary component to successful operation of the PBR plan. Accordingly, the Department rejects the Company's proposed ROERA.

g. Cost Treatment of Critical Infrastructure Projects

In its initial filing, NSTAR Electric proposed to recover costs associated with its critical infrastructure projects through a separate recovery factor at three intervals during the proposed ten-year PBR plan term (Exh. ES-CAH/DPH-1, at 82). In its rebuttal testimony, the Company proposed to eliminate the specific cost recovery factor associated with the critical infrastructure projects and instead would recover the costs associated with these projects through the K-bar adjustment (Exh. ES-PBR-Rebuttal-1, at 45). As discussed above, the Department has approved a K-bar adjustment as part of the Company's PBR plan, which would include recovery of costs associated with these projects. As such, a separate cost recovery factor associated with the critical infrastructure projects is unnecessary. Accordingly, the Company shall remove this factor from the PBR mechanism.

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[35] As noted in n.18 above, it appears that the Company acknowledges that the ROERA would not apply to a five-year PBR plan term.

h. ESM

The Company initially proposed an ESM that would trigger a sharing with customers on a 75/25 percent basis (75 percent to customers and 25 percent to the Company) where the computed distribution ROE exceeds 100 basis points above the ROE authorized in this proceeding (Exhs. ES-CAH/DPH-1, at 90; ES-PBR/PLAN-1, at 12). If the computed distribution ROE is between 150 and 200 basis points below the authorized ROE, sharing with customers would be triggered on a 50/50 percent basis (50 percent to customers and 50 percent to the Company) (Exhs. ES-CAH/DPH-1, at 90; ES-PBR/PLAN-1, at 12). If the computed distribution ROE exceeds 200 basis points below the authorized ROE, sharing with customers would be triggered on a 75/25 percent basis (75 percent to customers and 25 percent to the Company) (Exhs. ES-CAH/DPH-1, at 90; ES-PBR/PLAN-1, at 12). The Company proposed that for any year in which the ROE is above or below the bandwidth, the percentage of earnings that is to be shared with customers would be credited to customers in the succeeding year and that the impact of this prior year adjustment would be excluded from the calculation of the subsequent year's sharing (Exh. ES-CAH/DPH-1, at 91). In its rebuttal testimony, the Company did not propose to revise or remove the proposed ESM from the revised ten-year PBR plan (Exh. ES-PBR-Rebuttal-1, at 45).

The Department has found that ESMs may be integral components of incentive regulation plans, as they provide an important backstop to the uncertainty associated with setting the productivity factor. D.P.U. 17-05, at 400; D.P.U. 96-50 (Phase I) at 325; D.P.U. 94-50, at 197 & n.116. An ESM offers an important protection for ratepayers in the event that expenses increase at a rate much lower than the revenue increases generated by the PBR. D.P.U. 18-150, at 70; D.P.U. 17-05, at 400; Western Massachusetts Electric Company, D.P.U. 10-70, at 8 n.3 (2011); D.T.E. 05-27, at 404-405. For this reason, the Department finds that there is a significant benefit to implementing an ESM as part of the PBR mechanism adopted in this case.

The Company developed the proposed ESM in alignment with Department precedent for a ten-year PBR term (Exhs. ES-CAH/DPH-1, at 90; ES-PBR/PLAN-1, at 12). The Department has traditionally found that a PBR term of five years warrants an asymmetrical ESM with upside sharing with customers but no downside adjustments. D.P.U. 18-150, at 70-71; D.P.U. 17-05, at 400-401. Further, the Department has approved ESMs with deadbands of 100 basis points or greater. D.P.U. 19-120, at 89; D.P.U. 18-150, at 71-72; D.P.U. 17-05, at 401; D.T.E. 05-27, at 405; D.T.E. 03-40, at 500; D.P.U. 96-50 (Phase I) at 326. Moreover, as noted above, the Company proposed that, if a five-year PBR term is approved, the ESM would be asymmetrical with upside sharing for customers, but no downside adjustment for the Company (Exh. DPU 1-1).

In this Order, the Department has approved a PBR plan term of five years for NSTAR Electric. As such, we find it appropriate to approve an asymmetrical ESM with no downward adjustment. Specifically, the ESM will have a deadband of 100 basis points above the Company's authorized ROE. If the Company's actual ROE exceeds the authorized ROE by more than 100 basis points, the earnings above the deadband will be shared 75 percent with customers and 25 percent with the Company.

i. Exogenous Cost Factor

As noted above, NSTAR Electric initially proposed to include in the PBR adjustment formula an exogenous cost provision (or "Z factor"), in particular to address incremental property taxes arising from a municipality's change in valuation method for assessing utility property and for expenses incurred for certain Enterprise IT investments (Exhs. ES-CAH/DPH-1, at 83-86; ES-PBR/PLAN-1, at 7; ES-RDC-6, Sch. 1, at 455). The Company proposed that to be eligible for exogenous cost recovery the cost change must: (1) be beyond the Company's control; (2) arise from a change in accounting requirements or regulatory, judicial, or legislative directives or enactments; (3) be unique to the electric distribution industry as opposed to the general economy; and (4) meet a threshold of "significance" for qualification (Exhs. ES-CAH/DPH-1, at 83-84; ES-PBR/PLAN-1, at 7; ES-RDC-6, Sch. 1, at 455). The Company proposed the significance threshold for exogenous costs to be set at $4 million in 2023 and adjusted annually by the change in GDP-PI, except for exogenous costs associated with Enterprise IT expenses, for which the initial threshold would be set at $6 million (Exhs. ES-CAH/DPH-1, at 84-86; ES-PBR/PLAN-1, at 7; ES-RDC-6, Sch. 1, at 455). In its rebuttal testimony, the Company did not propose any revisions to the exogenous cost provision.

In D.P.U. 94-158, at 62, the Department recognized that there may be exogenous costs, both positive and negative, that are beyond the control of a company and, because the company is subject to a stay-out provision, these costs may be appropriate to recover (or return) through the PBR mechanism. The Department has defined exogenous costs as positive or negative cost changes that are beyond a company's control and are not reflected in the GDP-PI. D.P.U. 94-50, at 172-173. These include incremental costs resulting from: (1) changes in tax laws that uniquely affect the relevant industry; (2) accounting changes unique to the relevant industry; and (3) regulatory, judicial, or legislative changes uniquely affecting the industry. D.P.U. 96-50 (Phase I) at 291; D.P.U. 94-50, at 173. The Department has cautioned against expansion of these categories to a broader range. D.P.U. 96-50 (Phase I) at 290-291; D.P.U. 94-158, at 61-62. The Company proposed to adopt a definition of exogenous costs that is consistent with the definition adopted by the Department in D.P.U. 94-50 (Exhs. ES-CAH/DPH-1, at 83-84; ES-PBR/PLAN-1, at 7; ES-RDC-6, Sch.1, at 455). Accordingly, the Department finds that the Company's proposed definition of exogenous costs in this instance is appropriate.

In D.P.U. 96-50 (Phase I) at 292-293, the Department found that to avoid a costly regulatory process over minimal dollars, exogenous cost recovery must be subject to a significance threshold that is noncumulative (i.e., exogenous costs cannot be lumped together into a single total for purposes of determining whether the threshold has been met). See also D.T.E. 01-56, at 22-23; Boston Edison Company, D.T.E. 99-19, at 26 (1999). The Department notes that recently, in very limited circumstances, we have considered the total exogenous costs that occurred in a single year arising out of a change in regulatory guidance that induced a significant number of municipalities to change the method of valuing property for tax purposes. Eversource Gas Company of Massachusetts, D.P.U. 22-122, at 8-11 (October 31, 2022); NSTAR Gas Company, D.P.U. 22-121, at 12 (October 31, 2022);

NSTAR Gas Company, D.P.U. 21-107-A at 19-20 (October 28, 2022). The Department did not intend for these decisions to represent a wholesale shift in our standard that exogenous cost recovery must be subject to a significance threshold that is noncumulative. Therefore, the Department finds that NSTAR Electric must revise its proposed tariff to specify that the significance threshold is noncumulative, subject to the very limited circumstances noted above.[36]

As noted above, the Company proposed an exogenous cost significance threshold of $4 million for calendar year 2023, subject to annual adjustments thereafter based on changes in GDP-PI (Exhs. ES-CAH/DPH-1, at 84-86; ES-PBR/PLAN-1, at 7; ES-RDC-6, Sch. 1, at 455). Although the Department must consider the facts and circumstances of each case, the Department has previously found that an exogenous cost significance threshold was reasonable where it was equal to a multiple of 0.001253 times a company's total operating revenues. D.P.U. 20-120, at 97; D.P.U. 19-120, at 93-94; D.P.U. 18-150, at 66-67; D.P.U. 17-05, at 397; D.T.E. 03-40, at 491; D.T.E. 01-56, at 22-46; D.P.U. 96-50 (Phase I) at 293. Consistent with our precedent and facts of this case, the Department finds that $4 million is a reasonable exogenous cost significance threshold for the Company, which has total operating revenues of $3,136,349,876, and is implementing a multi-year PBR plan

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[36] For example, the tariff could read: The significance threshold for Exogenous Costs is set at $4 million for each individual event in calendar year 2023. The significance threshold must be noncumulative, subject to a finding that the exogenous costs arise from the same type of exogenous event addressed by the Department in NSTAR Gas Company, D.P.U. 21-107-A at 17-20 (October 28, 2022) and interpreted in subsequent decisions.

with the overall design approved herein (Exhs. ES-CAH/DPH-1, at 84-85; ES-REVREQ-2, Sch. 6 (Rev. 4)).[37]

In addition, the Company has proposed that the exogenous cost significance threshold be subject to annual adjustments based on changes in GDP-PI as measured by the U.S. Bureau of Economic Analysis (Exh. ES-CAH/DPH-1, at 85). The Department is satisfied that this proposal appropriately considers the effects that inflation will have on the threshold in the later years of the PBR term. D.P.U. 19-120, at 94; D.P.U. 18-150, at 67; D.P.U. 17-05, at 398; D.T.E. 01-56, at 11-14; Eastern Enterprises/Colonial Gas Company, D.P.U. 98-128, at 56-57 (1999). Accordingly, we set the Company's threshold for exogenous cost recovery at $4 million for each individual event in the first PBR year, ending December 31, 2023, subject to annual adjustments thereafter based on changes in GDP-PI as used in the PBR mechanism. Based on the foregoing analysis, the Department approves the Company's proposed exogenous cost factor, subject to our finding below as to Enterprise IT expenses.

Exogenous cost recovery requires that a company provide supporting documentation and rationale to the Department for a determination as to the appropriateness of the proposed exogenous cost. D.T.E. 99-19, at 25; D.P.U. 98-128, at 55; Bay State Gas Company, D.T.E. 98-31, at 17-18 (1998). Additionally, any company seeking recovery of an exogenous cost bears the burden of demonstrating the propriety of the exogenous cost and

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[37] Multiplying NSTAR Electric's total operating revenue of $3,136,349,876 by the factor of 0.001253 equals $3,929,846.

that the proposed exogenous cost change is not otherwise reflected in the GDP-PI. D.P.U. 96-50 (Phase I) at 292-293; D.P.U. 94-50, at 171. For these reasons, the Department does not prejudge the qualification of any future events as exogenous costs and will consider each proposal for recovery of exogenous costs on a case-by-case basis. At the time that it seeks exogenous cost recovery, the Company must demonstrate that the event meets both the definition and threshold for exogenous costs approved herein.

As noted above, the Company proposes to utilize the exogenous cost provision to recover the costs of certain Enterprise IT expenses, for which the initial threshold would be set at $6 million (Exhs. ES-CAH/DPH-1, at 84-86; ES-PBR/PLAN-1, at 7; ES-RDC-6, Sch. 1, at 455). The Attorney General argues that NSTAR Electric's proposed inclusion of certain Enterprise IT expenses in the exogenous cost factor should be rejected because ESC will incur these costs, and that the Company already is compensated for IT costs through base distribution rates and the annual PBR adjustments (Attorney General Brief at 59-60). Further, the Attorney General asserts that the Company does not recognize or net out any economic benefits that accrue as a result of the implementation of the new IT systems (Attorney General Brief at 60). TEC and PowerOptions also argue that these expenses should be excluded from the exogenous cost provision (TEC/PowerOptions Brief at 13; TEC/PowerOptions Reply Brief at 8-9).

The Company's justification for including Enterprise IT expenses in the exogenous cost provision is tied to the proposed ten-year PBR plan term (Exh. ES-CAH/DPH-1, at 88-89). The Company acknowledges that a level of Enterprise IT expense will be collected through base distribution rates and that will be subject to the annual PBR adjustment (Exh. ES-CAH/DPH-1, at 88). NSTAR Electric states, however, that over the proposed ten-year PBR term, the Company will be adding new systems and other systems will become fully amortized and drop off (Exh. ES-CAH/DPH-1, at 88). According to NSTAR Electric, it will be difficult for the Company to assess whether the amount of Enterprise IT expense that will be locked into base distribution rates will keep pace with actual costs and, therefore, the exogenous cost relief may be necessary (Exh. ES-CAH/DPH-1, at 89). Given that the Department has approved a five-year PBR plan term, we find that an exogenous cost provision applicable to Enterprise IT costs is unnecessary. Moreover, we find that the nature of the costs sought for exogenous cost treatment are inconsistent with the definition of exogenous costs approved herein. Thus, we deny this aspect of the Company's proposal. In its compliance filing, NSTAR Electric shall revise its PBR tariff accordingly.

j. PBR Adjusted Revenues

As noted above, the Attorney General argues that Solar Expansion Program investments should not be included in the base distribution rate revenue requirement portion of the PBR rate formula (Attorney General Brief at 117, citing Exh. AG-TN-1, at 9-10). In Section XIV.B.4 below, the Department approves the transfer of the unrecovered balance of these investments into base distribution rates. Here, the Department finds that it is appropriate to remove these costs from the PBR mechanism adjustment calculation and maintain the revenues associated with these solar facilities at the level approved in this proceeding until the Company's next base distribution rate case. The Solar Expansion

Program costs represent power generation costs, rather than distribution costs. Further, the costs associated with the Solar Expansion Program fall outside the Company's regular operations of safely and reliably delivering electricity to customers. Accordingly, the Company is not obligated to replace these assets when they retire, but it could continue to collect a revenue target that increases annually by the PBR mechanism. The Department has found it suitable to modify PBR plans or simplified incentive plans to exclude adjustments for certain types of costs. D.P.U. 18-150, at 73 (excluding solar facility costs from PBR adjustment); NSTAR Electric Company, D.P.U. 18-101 (2018), Exhs. NSTAR-DPH at 18; NSTAR-DPH-1, at 1 (certain storm costs excluded from PBR adjustment); D.P.U. 17-05, at 392 (removal of certain grid modernization investments); NSTAR Electric Company and NSTAR Gas Company, D.P.U. 08-56/D.P.U. 09-96, at 18-19 (2010) (removal of certain pension/post-retirement benefits other than pension ("PBOP") costs). The Department, therefore, directs the Company to revise the definition of PBR revenue to exclude the costs of the Solar Expansion Program approved in this proceeding, as well as other solar facilities that were approved in previous proceedings (see Section XIV.B.4 below).

6. PBR Tariff Provisions

As noted above, the Attorney General argues that, should the Department allow a PBR plan for NSTAR Electric, numerous provisions in the Company's proposed tariff should be revised to provide appropriate definitional and clarifying language (Attorney General Brief at 60-61). The Attorney General identifies 16 proposed revisions to the tariff (Attorney General Brief at 60-61).

Eight of the proposed revisions are no longer necessary given the Department's findings above regarding the PBR plan components. They are identified in the Attorney General's initial brief as proposed revisions (2), (5), (6), (7), (8), (9), (14) and (15). The Department approves five of the remaining proposed revisions that were agreed-upon by the Company. They are identified in the Attorney General's brief as proposed revisions (1), (4), (10), (11) and (16). The Company is directed to revise these provisions accordingly in the compliance filing.

Three contested proposed revisions remain. In proposed revision (3), the Attorney General argues that the definition of "Distribution Common Equity" in the proposed PBR plan tariff should reflect the removal of common equity associated with any: (1) unamortized acquisition premium and/or goodwill; and (2) non-distribution service investments and services (Attorney General Brief at 60-61). The Company disagrees with the Attorney General, "based on the Department's prior approvals, and method for calculating an ROE for earnings sharing purposes, as approved in D.P.U. 14-150, D.P.U. 17-05, and D.P.U. 19-120" (Company Brief at 79). The Company also asserts that its methodology in reporting the distribution-only ROE remains unchanged from what was approved in D.P.U. 17-05 as part of the existing PBR plan (Company Brief at 79). The Department finds that the definition of "Distribution Common Equity" in NSTAR Electric's proposed PBR plan tariff (Exh. ES-RDC-6, Sch. 2, at 235) is substantially similar to the language in the Company's current PBR plan tariff, M.D.P.U. No. 59E, § 1.04 (8). Further, the minor differences in the language between the two versions do not and should not be interpreted to impact the method used to derive distribution common equity for purposes of the PBR plan. The Attorney General does not provide any additional support for her argument, and we see no compelling reason to revise the definition as proposed. As such, we decline to adopt the Attorney General's recommendation.

In proposed revision (12), the Attorney General argues that the definition of "Transmission Net Income" does not account for any changes in the net income that might arise from refunds to customers as a result of any contested charges at Federal Energy Regulatory Commission ("FERC") (Attorney General Brief at 61). The Company argues that no revisions are necessary because the "calculation of ROE remains unchanged from D.P.U. 17-05" (Company Brief at 79). The definition of Transmission Net Income" in the proposed PBR plan tariff (Exh. ES-RCD-6, Sch. 2, at 237) is unchanged from the definition approved in the Company's current PBR plan tariff, M.D.P.U. No. 59E, § 1.04 (20). Nevertheless, we find that it is reasonable for the Company to include clarifying language that the transmission net income will account for any refunds to customers resulting from favorable FERC decisions as to contested charges. We direct the Company to revise the language accordingly in the compliance filing.

Finally, in proposed revision (13), the Attorney General argues that the X factor should be defined as "the sum of the Productivity Trend differential and the Input Price Trend," without the addition of "negative 1.45 percent ..." (Attorney General Brief at 61). The Company argues that the language in this definition will depend on the X factor approved in this proceeding (Company Brief at 79-80). In Section IV.D.5.b above, the

Department approved an X factor of zero. The Attorney General does not provide any additional support for her argument, and we find that the X factor should be expressly stated in this section of the tariff. Accordingly, we direct the Company to revise the relevant tariff language in the compliance filing to set the X factor at zero.

7. Conclusion

In the sections above, the Department has reviewed the Company's PBR plan proposals and has found that, as approved, the PBR plan is more likely than current regulation to advance the Department's goals of safe, secure, reliable, equitable, and least-cost service and to promote the objectives of economic efficiency, cost control, lower rates, and reduced administrative burden in regulation. G.L. c. 25, § 1A. In addition, the Department has found that the PBR plan, as approved, will provide the Company with greater incentives to reduce costs than currently exist and should result in benefits to customers that are greater than would be present under current regulation. Further, the Department has found that the PBR plan, as approved, better satisfies our public policy goals and statutory obligations, including promotion of a safe and reliable electric distribution system, and of the Commonwealth's clean energy goals and mandates.[38]

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[38] The Department notes that many cost recovery mechanisms need to be considered to ensure that EDCs comply with policy goals and statutory obligations effective since the development of revenue decoupling. See D.P.U. 07-50-A at 10. With the discontinuance of full revenue decoupling, EDCs no longer would have a disincentive to pursue strategic electrification because they now would be able to retain the sales from increased load, which may also obviate the need for some capital trackers. Nonetheless, we remind NSTAR Electric that with an approved PBR plan with a

With the modifications required herein, the Department finds that the PBR plan appropriately balances ratepayer and shareholder risk, is in the public interest, and will result in just and reasonable rates pursuant to G.L. c. 164 § 94. Accordingly, the Department approves a PBR plan for the Company, subject to the modifications above. The Company, in its compliance filing, shall submit a revised PBR plan tariff consistent with the findings in this Order.

Further, the Company shall submit an annual PBR adjustment filing, including all information and supporting schedules necessary for the Department to review the proposed PBR adjustment for the subsequent rate year. Such information shall include the results and supporting calculations of the PBR adjustment factor formula, descriptions and accounting of any exogenous events, and an earnings sharing calculation for the year, two years prior to the rate adjustment. In addition, the Company shall file revised summary rate tables reflecting the impact of applying the base distribution rate changes provided in the PBR adjustment filing. The Company is directed to submit its annual PBR adjustment filing on or before September 15 of each year, commencing in 2023 and continuing for the five-year term of the PBR. Consistent with our findings above, the PBR shall continue in effect for a total of five consecutive years starting January 1, 2023, with the last adjustment taking effect on January 1, 2027, subject to the findings set forth above.

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stay-out provision, the Company may not seek to terminate its effective PBR plan in order to discontinue revenue decoupling.

V. PBR PERFORMANCE METRICS

A. Introduction

The Company proposed a set of metrics as a component of its PBR proposal (Exhs. ES-CAH/DPH-1, at 10-11; ES-PBR-PLAN-1, at 4-5). The Company states that its proposed metrics are designed to provide transparency associated with the achievement of clean energy and customer service goals and to further the Company's mission of ensuring safe and reliable delivery of electric service (Exhs. ES-CAH/DPH-1, at 10-11; ES-METRICS-1, at 11). Further, the Company states that the proposed metrics are designed to further current Commonwealth policy goals (Exhs. ES-CAH/DPH-1, at 10-11; ES-METRICS-1, at 11). NSTAR Electric's proposed metrics were based initially on metrics developed for the Company's current PBR plan, following the Department's directive in D.P.U. 17-05, at 412, to develop metrics in three categories: (1) improvements to customer satisfaction and engagement; (2) reductions to system peak demand; and (3) strategic planning for climate adaptation and mitigation (Exh. ES-METRICS-1, at 10, 13). The Company proposed additional metrics to account for changes to the Commonwealth's policy goals, namely metrics for solar developer satisfaction, community solar access, electrification, and equity (Exh. ES-METRICS-1, at 41-42). During the proceeding, the Company proposed significant changes to its initially proposed set of metrics (Exhs. ES-METRICS-Rebuttal-1, at 9-32; ES-METRICS-Rebuttal-2).

By the close of the record in this proceeding, the Company proposed a total of ten reporting metrics, three penalty/incentive metrics, and two planning frameworks, across eleven categories (customer satisfaction, customer engagement, producer satisfaction, producer/developer engagement, operations, peak demand reduction, greenhouse gas ("GHG") reduction, electrification, equity/low-income, and resiliency) (Exh. ES-METRICS-Rebuttal-2; Company Brief at App. A). The Company proposes to report results on each metric as part of the annual PBR plan filings (Exh. ES-CAH/DPH-1, at 64-65). In addition, the Company proposes to provide a PBR performance report as part a five-year mid-term filing that summarizes performance on the metrics and recommendations for continuing, modifying, or augmenting the metrics (Exh. ES-CAH/DPH-1, at 93).

B. Company Proposal

1. Customer Satisfaction, Customer Engagement, and Operations Metrics

a. Introduction

The Company proposes the following five metrics in the categories of customer satisfaction and engagement and operations: (1) overall customer satisfaction in the Commonwealth (customer satisfaction); (2) transactional customer satisfaction (customer satisfaction); (3) customer usage of an outage map (customer engagement); (4) digital engagement (customer engagement); and (5) new customer connects (operations) (Exhs. ES-METRICS-1, at 22-27; ES-METRICS-Rebuttal-2, at 1-2).

b. Overall Customer Satisfaction Metric

The overall customer satisfaction metric is based on a survey conducted by J.D. Power that measures customer satisfaction using six factors: (1) power quality and reliability; (2) price; (3) billing and payment; (4) corporate citizenship; (5) communications;

and (6) customer service (Exhs. ES-METRICS-1, at 17; ES-METRICS-Rebuttal-2, at 1). Customer responses to these separate segments are compiled into one final index score (Exh. ES-METRICS-Rebuttal-2, at 1). NSTAR Electric states that during the current PBR term, the Company consulted with J.D. Power to set a target for the customer satisfaction score of 720 by the end of 2022 (Exh. ES-METRICS-1, at 17-18).[39] NSTAR Electric reports that by 2020 it had achieved a score of 739; the Company proposes a target of 759 for 2027 (Exh. ES-METRICS-1, at 21-23). NSTAR Electric states that it set these targets based on the score needed to achieve first quartile ranking among eastern large utility group companies in 2021, and the Company proposes to adjust the targets to maintain that ranking (Exh. ES-METRICS-1, at 23 & n.4).

c. Transactional Customer Satisfaction Index

NSTAR Electric proposes a customer satisfaction index that is designed to measure customer satisfaction associated with: (1) unplanned outages; (2) planned outages; (3) website satisfaction; and (4) contact center (Exh. ES-METRICS-Rebuttal-1, at 19-20). The proposed index score would be developed by summing the scores of survey responses from customers following each type of transaction and dividing by the sum of all respondents

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[39] In the current PBR term, NSTAR Electric has tracked customer satisfaction for both the entire Eversource Energy organization and the Company separately (Exh. ES-METRICS-1, at 16, 22). Going forward, the Company proposes to limit the metric to only its operations (Exh. ES-METRICS-1, at 16, 22).

(Exhs. ES-METRICS-Rebuttal-1, at 20; ES-METRICS-Rebuttal-2, at 1).[40] The Company proposes to include this metric in the Service Quality ("SQ") penalty framework, described below (Exhs. ES-METRICS-Rebuttal-1, at 18-19; ES-METRICS-Rebuttal-2, at 1).[41]

d. Use of Outage Map Metric

The Company's outage map provides customers with information such as estimated time of restoration, outage cause, and outage size so that customers can remain informed and make plans in the event of an outage (Exh. ES-METRICS-1, at 25-26). In prior years, the outage map usage metric has measured the total number of customer views of the outage map during both "blue sky" conditions and when the Company's Emergency Response Plan ("ERP") is triggered (Exh. ES-METRICS-1, at 25-26). In this proceeding, the Company proposes to report only on views during ERP events and to report engagements with the outage map as a percentage of total inbound customer communications during these events, rather than reporting a total count of interactions (Exh. ES-METRICS-1, at 25-26). The Company proposes that the calculation will be done on a per-ERP event basis and then

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[40] The Company proposes to weight the transaction type by the associated number of survey responses (Exh. ES-METRICS-Rebuttal-1, at 20).

[41] The Company does not propose to apply the SQ penalty/incentive framework to the overall customer satisfaction metric because this measure is not necessarily representative of actual interactions with the Company (Exh. ES-METRICS-Rebuttal-1, at 19). NSTAR Electric states that for many customers, their interactions with the Company are limited to billing issues, and that these limited interactions can skew customer satisfaction based on factors that are outside the Company's control (e.g., rising energy costs or increased demand due to weather) (Exh. ES-METRICS-Rebuttal-1, at 19).

averaged across all ERP events for the year, which is intended to account for annual variances in weather (Exhs. ES-METRICS-1, at 26; ES-METRICS-Rebuttal-2, at 1-2). NSTAR Electric reports that in 2020, 58 percent of customer engagements during ERP events were with the outage map, and the Company proposes a customer engagement target of 75 percent by 2027 (Exhs. ES-METRICS-1, at 26; ES-METRICS-Rebuttal-2, at 1).

e. Digital Engagement Metric

The Company's digital engagement metric is designed to track the percentage of total customer engagements that are digital (Exh. ES-METRICS-1, at 27). Digital interactions include bill pay, outage reporting, text message interactions, mobile app interactions, outage status checks, and others, while non-digital customer engagements include customer service phone calls and manual payments (Exhs. ES-METRICS-1, at 27; ES-METRICS-Rebuttal-2, at 2). NSTAR Electric reports that 88 percentage of total customer engagements were digital in 2020, and the Company proposes a target of 91 percent by 2027 (Exhs. ES-METRICS-1, at 27; ES-METRICS-Rebuttal-2, at 2).

f. New Customer Connects Metric

NSTAR Electric proposes a new metric for the percentage of new customer connects completed in accordance with Company targets for timeliness of new service connections (Exhs. ES-METRICS-1, at 44; ES-METRICS-Rebuttal-2, at 3). Specifically, the new customer connects metric will measure the time from the creation of a work order to the point of installation of the customer's meter in number of business days, excluding hold days[42] (Exh. ES-METRICS-1, at 44). The Company proposes to calculate the metric as the percentage of new customer connects that meet certain performance targets out of the total number of new customer connects (Exh. ES-METRICS-1, at 44). The Company and stakeholders developed and agreed upon performance targets that vary depending on the type of service (i.e., simple services, residential developments, complex residential, commercial developments, and commercial service) (Exh. ES-METRICS-1, at 45).[43] The Company proposes a target of 80 percent of connections within the agreed-upon range in year one and to increase the target by 2.5 percent each year until 90 percent is reached in year five (Exh. ES-METRICS-1, at 45-46). Finally, the Company proposes to include the new customer connects metric in the SQ Guidelines penalty framework,[44] as described below (Exhs. ES-METRICS-Rebuttal-1, at 21, 23; ES-METRICS-Rebuttal-2, at 3).

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[42] Hold days are delays that are defined as being outside of the Company's control, in the form of waiting for customer payment or waiting for customer permits or easements (Exh. ES-METRICS-1, at 44).

[43] Performance target ranges were developed during the Department's Working Group Meetings for Improving and Expediting the Process for new Electric and Gas Interconnections and range from five to eight business days for simple service to 63-121 days for residential developments (Exh. ES-METRICS-1, at 45).

[44] The SQ Guidelines refer to the guidelines adopted in Order Adopting Revised Service Quality Standards, D.P.U. 12-120-D (2015) and set forth at D.P.U. 12-120-D, Attachment A.

2. Producer Satisfaction and Producer/Developer Engagement Metrics

a. Introduction

The Company proposes metrics specifically related to the satisfaction and engagement of producer customers ("producers"), which the Company defines as customers that install a solar system (Exh. ES-METRICS-1, at 27-28). The Company proposes the following three producer satisfaction metrics: (1) a producer satisfaction survey (producer satisfaction); (2) hosting capacity map usage (producer/developer engagement); and (3) a solar development timeline (producer/developer engagement) (Exhs. ES-METRICS-1, at 27-28; ES-METRICS-Rebuttal-2).

b. Producer Satisfaction Survey

The Company states that the producer satisfaction survey will measure producer satisfaction associated with: (1) ease of enrollment; (2) ease of connection; (3) timeliness; and (4) helpfulness and communication during the interconnection process (Exh. ES-METRICS-Rebuttal-2, at 2-3). The survey was developed collaboratively by the Company and J.D. Power and is comprised of two surveys, one sent 65 days after the customer is interconnected and another sent 365 days after the customer is interconnected (Exhs. ES-METRICS-1, at 28; DPU 42-3). NSTAR Electric reports that, on a scale of one to ten, the Company scored an average of 7.01 in producer satisfaction in 2019, and the Company sets a target average of 7.5 producer satisfaction for 2027 (Exhs. ES-METRICS-1, at Table 1; ES-METRICS-Rebuttal-2, at 2-3).

c. Hosting Capacity Map Usage Metric

NSTAR Electric states that the hosting capacity map usage metric will measure the sum of visits to the Company's DG hosting capacity websites (Exhs. ES-METRICS-1, at 28-29; ES-METRICS-Rebuttal-2, at 3). The maps provide solar developers with information about remaining capacity at both the circuit and substation level and allow developers to make more informed decisions about the feasibility of adding DG to the distribution system (Exh. ES-METRICS-1, at 28-29). NSTAR Electric reports that it recorded 9,193 visits to the maps in 2020, and the Company proposes a target of over 18,000 visits by 2027 (Exhs. ES-METRICS-1, at 29; DPU 13-5).

d. Solar Development Timeline Metric

The Company states that the solar development timeline metric will measure the duration in business days from creation of a solar installation work order to completion (excluding hold days), and then will calculate the percentage of solar installations meeting certain timeline performance targets by dividing the number of solar installations that meet the targets by the total number of solar installations (Exhs. ES-METRICS-Rebuttal-1, at 20-21; ES-METRICS-Rebuttal-2, at 3). The Company proposes to include the solar development timeline metric in the SQ penalty framework (Exh. ES-METRICS-Rebuttal-1, at 20-21).

3. Proposed Incorporation of Three Metrics into SQ Penalty Framework

The Company proposes to include penalties and incentives for a subset of metrics, determining that such a framework would create transparency and accountability that can be objectively measured (Exh. ES-METRICS-Rebuttal-1, at 22-24). The Company proposes to replace three metrics that also currently are required to be reported under the Department's SQ Guidelines (consumer complaints, consumer credit cases, and service appointments kept), with three of the proposed metrics discussed above (new customer connects, transactional customer satisfaction index, and the solar development timeline) (Exhs. ES-METRICS-Rebuttal-1, at 23; ES-METRICS-Rebuttal-2, at 1, 3).[45] The Company's proposed substitution would take place after three year of data is collected to establish a benchmark for each metric, after which the penalty threshold for each metric would be set at the mean plus one standard deviation, based on the data (Exh. ES-METRICS-Rebuttal-1, at 23).[46] The Company also proposes for a symmetrical incentive to apply to the metrics that are incorporated into the SQ framework (Exh. ES-METRICS-Rebuttal-1, at 23-24). The Company states that the SQ penalty framework is familiar to the stakeholders in this proceeding, as the SQ Guidelines have been extensively vetted before adoption by the Department (Exh. ES-METRICS-Rebuttal-1, at 24).

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[45] NSTAR Electric states that it will continue to report on the original SQ Guidelines metrics to ensure that its performance does not diminish (Exh. ES-METRICS-Rebuttal-1, at 24).

[46] The Company proposes to apply the same methodology pursuant to the SQ Guidelines; specifically, the threshold benchmark would be set at the Company-specific mean plus one standard deviation using historical, Company-specific data with the benchmark adjusting every three years based on a rolling average until the tenth year when the benchmark becomes fixed (Exh. ES-METRICS-Rebuttal-1, at 23). In addition, under the Company's proposal, the three metrics would each be allocated a 15-percent weight in the SQ penalty framework (Exh. ES-METRICS-Rebuttal-1, at 23).

4. Peak Demand Reduction Metric

The Company proposes to track peak demand reductions from six measures: (1) energy efficiency programs; (2) demand response programs; (3) company-owned storage; (4) company-owned solar; (5) upgrades to standard technologies; and (6) volt/volt-ampere reactive optimization ("VVO") (Exhs. ES-METRIC-Rebuttal-2, at 4-6; DPU 49-1, at 3-4). The Company explains that the measures target reductions to different, non-coincident peaks (e.g., demand response targets ISO New England Inc. ("ISO-NE") system peak, and VVO targets a substation peak) (Exhs. DPU 41-3; DPU 68-9). Therefore, NSTAR Electric does not propose to aggregate the reductions across measures or set a common target based on system peak, but rather the Company intends to set separate baselines and targets for each peak reduction measure (Exh. ES-METRIC-Rebuttal-2, at 4-6; Tr. 5, at 404-407).

5. Climate Adaptation and Mitigation Plan

NSTAR Electric proposes to pursue an updated enterprise-wide[47] climate adaptation and mitigation plan, which focuses on bringing renewable energy to the region and reducing the Company's own emissions (Exhs. ES-METRICS-1, at 39; ES-METRICS-2, at 3; DPU 23-2). In addition, the Company proposes to adopt a goal of reducing emissions by ten percent from a 2022 baseline by 2027 (Exhs. ES-METRICS-1, at 39-40; ES-METRICS-Rebuttal-2, at 6). NSTAR Electric states that emissions reductions will focus on enabling a cleaner mix of energy on the grid, improving efficiencies in distribution

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[47] Enterprise-wide includes all of the utility operating companies in the Eversource Energy holding company system.

infrastructure to reduce system losses, reducing electricity and fuel use at facilities by upgrading heating ventilating air conditioning ("HVAC") equipment and lighting to be more efficient, updating fleet vehicles with electric and hybrid models and using alternative fuel sources, and reducing sulphur hexafluoride leaks (Exhs. ES-METRICS-1, at 39-40; ES-METRICS-2, at 4-6).[48]

The climate adaptation and mitigation plan also includes hardening the Company's electric power system to withstand climate change impacts and engaging and supporting stakeholders to pursue a clean energy future (Exhs. ES-METRICS-1, at 39; ES-METRICS-2, at 3). Specifically, under the climate adaptation and mitigation plan, NSTAR Electric proposes continued development of a substation flood vulnerability model, evaluation of new equipment to improve performance in flooding conditions, and augmentation of the Company's outage prediction model to include climate impacts (Exh. ES-METRICS-1, at 40).

6. Equity and Electrification Planning Frameworks

a. Introduction

Two metrics initially proposed by the Company related to equity and electrification objectives were ultimately reproposed as planning frameworks (Exhs. ES-METRICS-1, at 42,

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[48] The Company also notes that, as proposed, emission reductions measured against the target will also come from reducing methane leaks in the natural gas distribution system, as the Company's emissions targets are enterprise-wide and include all operating companies across three states (Exhs. ES-METRICS-1, at 39; ES-METRICS-2, at 5; DPU 23-2).

46-49; ES-METRICS-Rebuttal-1, at 10-11).[49] As planning frameworks, the Company proposes to commit to a set of principles regarding electrification and equity consistent with the Commonwealth's policy priorities (Exh. ES-METRICS-Rebuttal-1, at 10). The Company's proposed planning frameworks include commitments to meet policy objectives and to increase transparency through annual reporting (Exh. ES-METRICS-Rebuttal-1, at 11, 17). Both planning frameworks would apply to capital investment projects of $20 million or greater (Exh. ES-METRICS-Rebuttal-1, at 12).[50] As planning frameworks, the Company proposes not to measure a baseline or set targets (Exh. ES-METRICS-Rebuttal-1, at 11-12).

b. Electrification Enabling Investment Framework

The proposed electrification enabling investment framework ("electrification framework") guides future infrastructure to be sized to facilitate the Commonwealth's "All Options" pathway for meeting 2050 decarbonization goals (Exh. ES-METRICS-Rebuttal-1, at 13). See The Massachusetts 2050 Decarbonization Roadmap. Specifically, the electrification framework includes the following planning standards for future bulk station projects: (1) to enable 80 percent of the expected EV load for light duty vehicles based on

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[49] The Company determined that the concepts of clean energy/electrification and equity are not well suited to a quantitative metric at this time (Exh. ES-METRICS-Rebuttal-1, at 10). Further, the Company also removed from its proposal a community solar access metric because the Department has not yet approved a community solar program (Exh. ES-METRICS-Rebuttal-1, at 10 & n.3).

[50] NSTAR Electric proposed the $20-million threshold because this level is the minimum cost of substation expansion; the threshold is therefore intended to capture every substation expansion that would be needed for electrification enablement (Tr. 5, at 383).

unmanaged charging behavior; (2) to enable 50 percent of charging for medium and heavy duty EVs; (3) to provide four fast charging stations at 150 kilowatt hour ("kWh") each for every 50 miles of interstate roadway covered within the Company's service area with a 75-percent utilization; and (4) to enable conversion of 100 percent of residential and 78 percent of commercial heating load to heat pumps, and 22 percent of commercial heating load to electric heating (Exh. ES-METRICS-Rebuttal-1, at 13-14). The Company proposes to include in its annual PBR filing a report on any bulk station project initiated during the PBR plan term and how it complies with the electrification framework (Exh. ES-METRICS-Rebuttal-1, at 14).[51]

c. Equity Framework

NSTAR Electric proposes an equity framework that would be applied to projects in all Environmental Justice ("EJ") communities (Exhs. ES-METRICS-Rebuttal-1, at 14-16; ES-METRICS-Rebuttal-3; RR-DPU-21).[52] NSTAR Electric states that the equity framework consists of initial steps toward increased efforts to integrate equity considerations in the Company's decision making and in community engagement (Exh. ES-METRICS-Rebuttal-1, at 15). The Company identifies the following five methods for increasing stakeholder

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[51] The Company also proposes to include an explanation for how its bulk station project is sized to meet the proposed criteria in the need assessment supporting an application for approval to site the project (Exh. ES-METRICS-Rebuttal-1, at 14).

[52] The Company will adopt the Commonwealth's definition of EJ Community as defined in Chapter 8 of the 2021 Climate Act, using the Executive Office of Energy and Environmental Affairs' population criteria, or another definition promulgated by the Commonwealth (RR-DPU-21).

engagement on equity issues that will be applied through the framework: (1) rigorous EJ mapping; (2) identification of stakeholders and focused outreach to those stakeholders; (3) language translation and live interpretation services; (4) public engagement utilizing a variety of communication channels and in multiple languages, as applicable; and (5) collection of feedback (Exhs. ES-METRICS-Rebuttal-1, at 16-17; ES-METRICS-Rebuttal-3). NSTAR Electric proposes to include in its annual PBR filing a description of the Company's actions to implement the planning framework (Exh. ES-METRICS-Rebuttal-1, at 17-18).

7. Resiliency Metrics

In response to intervenor and Department requests, the Company developed two metrics related to system resiliency. First, based a recommendation by TEC and PowerOptions, the Company proposes a reporting metric on Momentary Average Interruption Frequency Index ("MAIFI"), and states that such reporting will be limited to devices with SCADA[53] visibility until advanced metering infrastructure ("AMI") meters are deployed (Exh. ES-METRICS-1, at 25-26; Company Brief at 123-124, App. A at 7).[54] Second, in response to a Department record request, the Company proposes "all-in" System Average Interruption Duration Index ("SAIDI") and System Average Interruption Frequency Index

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[53] SCADA refers to the Supervisory Control and Data Acquisition system that monitors substations, transformers, and other electrical assets.

[54] The Company states that following deployment of AMI meters, momentary data from each customer will be integrated into the momentary outage dashboard to provide a more accurate MAIFI score (Exhs. METRICS-Rebuttal-1, at 26; DPU 68-7).

("SAIFI") metrics as part of its annual PBR metric reporting to measure system resiliency (RR-DPU-16). The Company states that, unlike current measures that exclude certain major event days, its proposed all-in metrics will capture all customer interruptions and customer interruption duration without excluding major event days (RR-DPU-16). NSTAR Electric states that by creating parallel SAIDI and SAIFI evaluations that include major events, the Company's understanding and accounting of the impact of resiliency measures on reliability will improve (RR-DPU-16). Further, NSTAR Electric states that the all-in SAIDI and SAIFI metrics will remain reporting-only metrics until sufficient data has been collected to establish a baseline and target (RR-DPU-16).

8. Low-Income Terminations Metric

In response to a request from the Low-Income Network, the Company proposes to include a metric that will provide reports on low-income customer service terminations (for nonpayment and for accounts with past due balances at levels eligible for disconnect) by census tract (Exhs. ES-METRICS-Rebuttal-1, at 31; LI-ES 2-1). The Company proposes to report data starting pre-pandemic with the 2019 calendar year (Exhs. ES-METRICS-Rebuttal-1, at 31; LI-ES 2-1).

C. Positions of the Parties

1. Attorney General

a. Introduction

The Attorney General argues that the Company is generally proposing to reuse the metrics proposed in NSTAR Electric Company, D.P.U. 18-50, which have not yet been approved and were shown by the Attorney General and other intervenors to be deeply flawed (Attorney General Brief at 65-66).[55] Further, the Attorney General contends that the Company's additional, new metrics proposed for the 2023-2027 PBR term are either flawed or underdeveloped and cannot measure or ensure whether the Company's proposed PBR plan delivers any benefits to ratepayers that would be attributable to the PBR mechanism (Attorney General Brief at 66; Attorney General Reply Brief at 10-11). In particular, the Attorney General claims that NSTAR Electric's proposed metrics are overly focused on incentivizing spending rather than achieving performance goals, and would, therefore, trigger increases in required revenues and customer rates (Attorney General Brief at 77, citing Exh. AG-DPL-PBR-Surrebuttal-1, at 13). According to the Attorney General, the Department should not approve any extension or replacement PBR plan for NSTAR Electric unless and until the Company identifies and corroborates meaningful benefits to ratepayers that can be attributed directly to, or enabled by, the substantial increase in annual revenues occasioned by the PBR plan and can be adequately measured and verified (Attorney General Brief at 66). Thus, the Attorney General asserts that the Department, the Company, and affected stakeholders all need to devote more thought and creativity to identify meaningful performance goals for a PBR plan – in terms of measurable performance outputs – before approving a PBR mechanism for NSTAR Electric (Attorney General Brief at 66).

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[55] Additionally, the Attorney General contends that the Company is unable to show that it has met its metrics for the 2018 to 2022 PBR term (Attorney General Brief at 66, 68).

Alternatively, if the Department approves NSTAR Electric's proposed PBR plan, the Attorney General argues that implementation of the PBR term should be delayed until the Company develops, and stakeholders review and comment on, metrics that ensure accountability, and will measure benefits that can be attributed to or enabled by the annual increase in PBR revenues (Attorney General Brief at 65-66). The Attorney General further asserts that the Department should require the Company and affected stakeholders to collaborate to identify documented outcomes that ensure progress in the clean energy transition and require the Company to document and demonstrate progress towards agreed-upon milestones and benchmarks (Attorney General Reply Brief at 13).

b. Overall Customer Satisfaction Metric

The Attorney General argues that the Company's proposed overall customer satisfaction metric does not represent a commitment to improve customer service and would not incentivize performance gains (Attorney General Brief at 70). The Attorney General contends that the customer satisfaction metric is the only customer-service-related metric that includes an objective, quantifiable target (Attorney General Brief at 68 n.73).[56] Further, the Attorney General claims that score improvements in prior years with and without a PBR plan in place indicate that a PBR plan is not essential to improve customer service (Attorney General Brief at 69). Finally, the Attorney General argues that the Company's proposed

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[56] The Attorney General cites to the Eversource Energy organization's score of 711, which she argues fell short of the 2022 target of 720 set for the Company's current PBR term (Attorney General Brief at 69 n.74, <u>citing</u> Exh. ES-METRICS-1, Table 1).

2027 target score of 759 represents what it could achieve conducting business as usual and that it is unlikely to result in a first quartile ranking among industry peers in 2027 (Attorney General Brief at 70, citing Exh. ES-METRICS-1, at 23 n.4).

c. Customer Total Satisfaction Index and Solar Development Timeline

The Attorney General contends that while customer service improvements and adherence to a solar development timeline are important performance areas that the Department should track and measure, including these two measures in the existing SQ reporting is highly problematic (Attorney General Brief at 75, citing Exh. AG-DPL-PBR-Surrebuttal-1, at 9). First, the Attorney General argues that replacing the metrics would necessitate a consideration of whether the current cap placed on SQ penalties remains appropriate, considering potential asymmetry between the cost risk against ratepayers and the penalty risk for the Company (Attorney General Brief at 75, citing Exh. AG-DPL-PBR-Surrebuttal-1, at 11-12). Second, the Attorney General asserts that adding performance measures to the SQ Guidelines may weaken the existing penalty on the established SQ metrics if the Department were to make room for new metrics under the penalty cap (Attorney General Brief at 75). Finally, the Attorney General contends that including these prospective performance measures would be a departure from the Department's practice of reviewing its SQ Guidelines holistically and developing uniform metrics across all companies (Attorney General Brief at 75-76). Thus, the Attorney General asserts that further stakeholder consideration is needed before these metrics are implemented (Attorney General Brief at 76).

d. Peak Demand Reduction Metric

The Attorney General argues that NSTAR Electric's proposed peak demand reduction metric measures only the demand reduction results achieved under programs initiated prior to the Company's current PBR, rather than complying with the Department's directive in D.P.U. 17-05 to propose metrics that track peak demand reductions directly attributable to investments enabled by the PBR itself (Attorney General Brief at 70-71; Attorney General Reply Brief at 13, citing D.P.U. 17-05, at 409-410). Further, the Attorney General contends that the demand reduction targets (e.g., energy efficiency, company-owned solar, upgraded technology investments, and initiation of VVO) are all programs, initiatives, and results that already have been separately funded by ratepayers through explicit customer surcharges and cost recovery mechanisms (Attorney General Brief at 71-72). Thus, the Attorney General asserts that the Company cannot claim these reductions as ratepayer benefits from a PBR plan (Attorney General Brief at 72). Finally, according to the Attorney General, the Company has failed to implement the one metric that the Department ordered that could assess performance under the PBR, namely the percent demand reduction enabled by investments under the PBR plan (Attorney General Brief at 72-73, citing D.P.U. 17-05, at 410; Attorney General Reply Brief at 13).

e. Climate Adaptation and Mitigation Plan

The Attorney General argues that the Company's proposed climate adaptation and mitigation plan is simply a list of routine operations changes and not future commitments to mitigate emissions or harden infrastructure enabled by the PBR plan (Attorney General Brief at 76). According to the Attorney General, the facilitation of new sources of renewable energy supply, company-owned solar, grid modernization investments in voltage reduction and VVO, and more aggressive vegetation management are already separately funded and incentivized by ratepayers, and certain storm hardening improvements are standard construction practices (Attorney General Brief at 76-77). Thus, the Attorney General rejects any notion that these measures are attributable to the Company's performance under a PBR plan (Attorney General Brief at 77).

f. Equity and Electrification Planning Frameworks

The Attorney General argues that the Company's proposals to develop frameworks for assessing progress on clean energy transition and electrification and an improvement of EJ contain no substantive measures (Attorney General Brief at 73, citing Exh. AG-DPL-PBR-Surrebuttal-1, at 6-9). The Attorney General maintains that the proposed electrification framework would shift significant risk of potential overbuilding and overspending onto ratepayers (Attorney General Brief at 73-74, 77-78, citing Exh. AG-DPL-PBR-Surrebuttal-1, at 8, 10).[57] Further, the Attorney General asserts that the proposed planning frameworks merit broader inquiry and examination and encourages the

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[57] The Attorney General explains that if the Company were directed through an output-focused PBR metric to target 90 percent of future EV charging load as managed load rather than its currently proposed electrification framework that projects to plan all future bulk station upgrades to accommodate up to 80 percent of unmanaged EV charging load, it would enable substantial capital savings and far more capable systems for the Company and its ratepayers (Attorney General Brief at 77-78; Attorney General Reply Brief at 12-13, citing Exh. AG-DPL-PBR Surrebuttal-1, at 9-11).

Department to create a stakeholder review process before the Department allows the Company's proposed PBR plan (Attorney General Brief at 74). Moreover, the Attorney General contends that the electric sector modernization plan development process, required by the 2022 Clean Energy Act, will address the issues that the Company's electrification framework seeks to address, and, therefore, the Department should not approve new planning standards in advance of this legislatively mandated process (Attorney General Brief at 74).

Regarding the Company's proposed equity framework, the Attorney General argues that, if approved, the Department should make clear that demonstrating compliance with the framework does not necessarily satisfy any Company obligation to address EJ or other equity issues in proceedings before the Department (Attorney General Brief at 74 n.77).

2. DOER

a. Introduction

DOER contends that by changing some of its proposed metrics throughout the proceeding, NSTAR Electric demonstrated that the development of effective performance metrics should not only be the Company's responsibility, but rather should involve a broader, more transparent stakeholder process (DOER Brief at 20-21). Further, DOER claims that the Company's proposed metrics do not appropriately incentivize support for clean energy goals, nor do they measure progress under the PBR plan (DOER Brief at 19; DOER Reply Brief at 2).

Despite these concerns, DOER asserts that the proposed metrics should be approved (DOER Brief at 19). DOER, however, recommends that the Department convene a stakeholder proceeding involving the EDCs to develop, over the next five years, more robust performance metrics that include performance incentives and direct benefits to ratepayers of the clean energy transition (DOER Brief at 10, 19-20; DOER Reply Brief at 2-3). In this regard, DOER asserts that the Grid Modernization Advisory Council could be the forum for coordination with stakeholders regarding comprehensive metrics (DOER Brief at 24; DOER Reply Brief at 3). Finally, DOER argues that approval of the Company's proposed metrics may provide additional information that can help develop more effective metrics, but that the Department should not consider the proposed metrics as the end goal (DOER Brief at 20).

b. Equity and Electrification Planning Frameworks

As noted above, the Company initially proposed two metrics related to equity and electrification, but later modified the proposals as planning frameworks (Exhs. ES-METRICS-1, at 42, 46-49; ES-METRICS-Rebuttal-1, at 10-11). DOER disagrees with the Company's position that equity and electrification are not well-suited to a quantitative metric and contends that tracking the benefits of the Company's investments on EJ populations and on electrification goals is both possible and necessary (DOER Brief at 22, citing Exh. ES-METRICS-Rebuttal-1, at 10). DOER supports the Department's approval of the equity and electrification frameworks but asserts that they should be further developed before the next PBR filing (DOER Brief at 21-23).

c. MAIFI

DOER supports the reporting on MAIFI and asserts that these outages will become increasingly important as residential electrification accelerates (DOER Reply Brief at 8, citing

Exh. TEC/PO-JDB-1, at 17; TEC Initial Brief at 12). Further, DOER contends that this metric and any subsequently refined metrics should be consistently applied to all EDCs in future proceedings (DOER Reply Brief at 8-9).

d. Low-Income Terminations Metric

DOER supports approval of the low-income terminations reporting metric (DOER Brief at 21). DOER asserts that maintaining this data would assist the Company and stakeholders in better understanding the scale of low-income ratepayer's service disconnections and assist in identifying potential new policies and programs that would support low-income ratepayers' avoiding disconnections (DOER Brief at 21, citing Exhs. ES-METRICS-Rebuttal-1, at 31; LI-ES 2-1).

3. Low-Income Network

The Low-Income Network supports implementation of the Company's proposed low-income terminations metric (Low-Income Network Letter in Lieu of Reply Brief at 1). According to the Low-Income Network, the reporting requirement associated with this metric will provide invaluable guidance about the many efforts that the Company is making to maintain affordable bills for low-income customers (Low-Income Network Letter in Lieu of Reply Brief at 1, citing Exh. LI-ES 2-1).

4. Acadia Center

Acadia Center argues that the Company's metrics do not meet the Department's standards and lack financial incentives and consequences (Acadia Center Brief at 15). In particular, Acadia Center contends that the proposed metrics do not go far enough, and that they over-emphasize grid-side capital investment and ignore demand-side flexibility and management (Acadia Center Brief at 16, citing Exhs. AG-DLP-Surrebuttal-1, at 4; AG-DPL-1, at 3). Further, Acadia Center contends that the metrics do not measure benefits attributable to the PBR plan (Acadia Center Brief at 16, citing Exh. UMASS-EP/RS-1, at 59). In addition, Acadia Center asserts that the Department should adopt metrics that meaningfully reduce energy burdens, promote equity, help to accelerate decarbonization of buildings, and reward a utility for ensuring that consumers below the poverty level are on income-eligible rates (Acadia Center Brief at 16). Finally, Acadia Center suggests that a shared savings mechanism that pushes the Company to implement more non-wires alternatives may be useful (Acadia Center Brief at 16).

5. Cape Light Compact

a. Introduction

Cape Light Compact argues that the Department should expedite issuance of its Order in D.P.U. 18-50 to provide due process to intervenors, as the lack of a final decision is unfair to the parties who participated in that docket, and creates confusion as to how those issues will be considered in light of the Company's proposed changes to its metrics in the instant case (CLC Brief at 33-34). Further, Cape Light Compact contends that given the uncertainty over what measures the Company would use for emissions reductions in its climate adaptation and mitigation plan metric and uncertainty regarding how this proceeding interplays with D.P.U. 18-50, the Department should direct a compliance phase or stakeholder review regarding the proposed metrics (CLC Reply Brief at 13-14, citing Attorney General Brief at 74, 78).

b. Climate Adaptation and Mitigation Plan

Cape Light Compact argues that light emitting diode ("LED") lighting replacement should not be included in the Company's climate adaptation and mitigation plan because the Company confirmed that it will complete such replacements by the end of 2022 and LED lighting has become industry standard (CLC Brief at 35-36, citing Exhs. ES-METRICS-Rebuttal-1, at 30; CLC-KFG-1, at 13; CLC-KFG-4; Tr. 5, at 366-367; CLC Reply Brief at 13, citing Company Brief at 124). Cape Light Compact asserts that if the Department approves the Company's climate adaption and mitigation plan with LED lighting replacement included, then it should direct NSTAR Electric to expand its LED replacements to non-LED Rate S-1 (Company-owned) lighting to further reduce emissions (CLC Brief at 33, 36; CLC Reply Brief at 13-14). Finally, Cape Light Compact contends that, despite being outside of the Company's intended scope of Company facility-related emissions, the climate adaption and mitigation plan should be allowed to evolve to where emissions reductions are necessary (CLC Brief at 36, citing Tr. 5, at 373).

6. CLF

CLF also argues that the use of LED lighting is now an industry standard (CLF Brief at 13). As such, CLF asserts that NSTAR Electric should not be rewarded for such measures and that LED lighting replacement should not be included as part of the climate adaptation and mitigation plan (CLF Brief at 13, citing Exh. CLC-KFG-1, at 13-15).

7. TEC and PowerOptions

TEC and PowerOptions argue that the Department should approve reporting on MAIFI as a PBR metric once AMI meters are deployed and also in the interim on an as-available basis (TEC/PowerOptions Brief at 12-13, citing Exhs. ES-METRICS-Rebuttal-1, at 26; DPU 68-7). TEC and PowerOptions assert that a MAIFI metric should have no associated penalties, since the goal is to improve visibility into the operation of the distribution system (TEC/PowerOptions Brief at 12-13).

8. UMass

a. Summary

UMass argues that establishing effective metrics is critical to an effective PBR plan but is difficult and requires stakeholder involvement and focused consideration (UMass Brief at 47). With respect to the Company's proposed metrics, UMass contends that they do not measure benefits that ratepayers may receive that are attributable to the PBR plan, and, therefore, they do not encourage the Company to leverage the PBR plan to customers' benefit (UMass Brief at 51, citing Exh. UMASS-EP/RS-1, at 59; Tr. 5, at 375-376). Further, UMass contends that although the Company's proposal to incorporate financial incentives for performance is a significant and potentially positive step, the proposal was made so late in the proceeding that it has not been fully developed with robust stakeholder engagement and requires refining to align the financial incentives with customer benefits (UMass Brief at 52, citing Exh. UMASS-EP/RS-1, at 59-60).

UMass asserts that the Department should deny NSTAR Electric's proposed PBR plan pending development of acceptable metrics, and then expedite a separate proceeding to finalize metrics (UMass Brief at 48). In this regard, UMass contends that it is the Company's burden to establish adequate metrics, including developing a sufficient record, and that the Department has the authority to reject rate changes if a company fails to meet its burden (UMass Reply Brief at 12 (internal citations omitted)). UMass asserts that delaying the implementation of the proposed PBR plan would not prevent the Department from approving new rates to address the Company's revenue deficiency, but rather would delay automatic rate increases associated with the PBR plan (UMass Reply Brief at 12).

b. Overall Customer Satisfaction Metric

UMass argues that NSTAR Electric's overall customer satisfaction metric should include the Company's ranking relative to peer companies instead of just the Company's absolute numerical score (UMass Brief at 53, citing Exh. UMASS-EP/RS-1, at 62-63, 67).[58] UMass contends that the Company's recent customer satisfaction scores are low compared to other comparable utilities in the region, and that reporting on relative rankings of customer satisfaction would drive the Company to provide a higher level of service (UMass Brief at 53, citing Exh. UMASS-EP/RS-1, at 63-64).

Additionally, UMass argues that NSTAR Electric should also report on the overall satisfaction of its business customers instead of just its residential ones, as business customers

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[58] UMass asserts that the Company is amenable to reporting relative rankings (UMass Brief at 53, citing Tr. 5, at 399).

have different interests and priorities than residential customers (UMass Brief at 53, citing Exh. UMASS-EP/RS-1, at 62-64, 67). Finally, UMass supports the Company's transactional customer satisfaction metric, as it is more directly focused on the improvement of specific services to customers (UMass Brief at 53, citing Exhs. ES-METRICS-Rebuttal-1, at 18-20; ES-METRICS-Rebuttal-2, at 1; Tr. 5 at 390). However, UMass asserts that this metric alone does not remedy the absence of reporting on business customer satisfaction and relative rankings of customer satisfaction (UMass Brief at 53).

c. Peak Demand Reduction Metric

UMass argues that the Company's peak demand reduction metrics are inadequate since they would not track how the PBR plan resulted in peak demand reduction, but instead only report on the beneficial effects of programs unrelated to the PBR plan (UMass Brief at 53-54, citing Exhs. UMASS-EP/RS-1, at 64-65; ES-METRICS-Rebuttal-2, at 4-6; Tr. 5, at 408, 412-415, 417, 424).

d. Climate Adaptation and Mitigation Plan

UMass argues that because the Company's baselines are inconsistent with the Commonwealth's 1990 baseline, it is unclear whether NSTAR Electric's GHG emissions reduction targets align with Massachusetts policy or whether the Company's GHG reduction efforts are in any way connected to the PBR plan (UMass Brief at 54, citing Exh. UMASS-EP/RS-1, at 65-66; Tr. 5, at 401-402, 403). As such, UMass asserts that the Department should require the Company to present an analysis demonstrating how its own emission reduction targets compare to the Commonwealth's targets and policy (UMass Brief at 54, citing Exh. UMASS-EP/RS-1, at 65-66, 68).

e. Electrification Framework

UMass asserts that the proposed electrification metrics are too open-ended and should instead focus on ensuring that the Company expeditiously delivers the information, and ultimately the implementation, needed for interested customers to convert to electrification (UMass Brief at 52, citing Exh. UMASS-EP/RS-1, at 60-61). According to UMass, the Company should provide annual reporting on customer upgrade requests for electrification that include information on the customer, upgrade, timeline, and load impact (UMass Brief at 52-53, citing Exh. UMASS-EP/RS-1, at 61-62, 67).

9. Company

a. Introduction[59]

The Company rejects the notion that additional process is needed to further develop the metrics, and contends that the intervenors have been unwilling to provide concrete feedback during the instant proceeding (Company Reply Brief at 15, citing Attorney General Reply Brief at 10-13; Cape Light Compact Reply Brief at 13-14; UMass Reply Brief at 11-12).[60] Despite this contention, NSTAR Electric claims that the numerous iterations of

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[59] On brief, the Company discusses the metrics proposed in its initial filing and the changes made during the proceeding (Company Brief at 95-117). In the interest of administrative efficiency, the focus of this section will be the Company's response to the issues raised by the intervenors.

[60] In response to Cape Light Compact, the Company further notes that any adjustments made to the proposed metrics based on the record in D.P.U. 18-50 should only apply

the proposed metrics throughout the proceeding reflect the Company's effort to take feedback seriously and to incorporate it into its final proposals (Company Reply Brief at 16). The Company recommends that any further process should be conducted during the five-year PBR term, and that the Department should not delay implementation of the PBR plan (Company Reply Brief at 15). In response to DOER's recommendation for a stakeholder process that would address metrics for all EDCs, the Company notes that there are important differences across utilities that need to be considered when developing metrics, and, therefore, company-specific metrics are more appropriate than uniform metrics (Company Reply Brief at 17-18, citing DOER Brief at 3; Exh. DPU 63-4).

In response to intervenor arguments that metrics should be directly tied to PBR adjustments, the Company argues that the PBR mechanism is not designed to recover specific categories of costs, but rather is a formula designed to provide adequate support to meet policy goals (Company Brief at 117, citing Exh. DPU 13-10; Company Reply Brief at 17, 20). As such, the Company contends that it has designed metrics that can measure progress related to policy goals (Company Brief at 118). Further, the Company claims that progress on cost efficiency will not be determined through metrics, but rather based on a review of the drivers of a future request for rate increases (Company Reply Brief at 17, 20, citing Exh. DPU 13-1, at 1 n.1). Therefore, the Company asserts that the intervenors' arguments

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on a prospective basis (Company Reply Brief at 19, citing Cape Light Compact Reply Brief at 14).

are insufficient to reach a conclusion that the proposed metrics are deficient (Company Reply Brief at 17, 19-20, citing Attorney General Brief at 12-13; UMass Reply Brief at 11-12).

b. Overall Customer Satisfaction Metric

In response to the Attorney General's arguments, NSTAR Electric contends that Eversource Energy's failure to meet the enterprise-wide customer satisfaction target was due to circumstances beyond the Company's control that affected affiliates outside of Massachusetts (Company Brief at 119; citing Attorney General Brief at 69; Exh. ES-METRICS-1, at 22). Thus, the Company claims that an enterprise-wide measure for judging the efficacy of the Company's PBR plan is inappropriate (Company Brief at 119).

Further, the Company disagrees with the Attorney General's assertion that the Company's overall customer satisfaction target represents a "business as usual" level of service (Company Brief at 119, citing Attorney General Brief at 69-70). NSTAR Electric argues that even if its 2027 target score will not result in a first quartile ranking, it still represents a measure of improvement, and it is appropriate to select a target based on the score currently necessary to get a first quartile ranking (Company Brief at 119, citing Exh. ES-METRICS-1, at 23).

c. Peak Demand Reduction Metric

The Company rejects the notion that energy efficiency and demand reduction measures are not enabled by the PBR plan (Company Brief at 121). In response to the Attorney General, NSTAR Electric contends that the programs included in the peak reduction metric represent a substantial portion of the Company's peak load management efforts and removing them would provide an incomplete picture of the Company's peak reduction efforts (Company Brief at 121, citing Attorney General Brief at 70).

d. Climate Adaptation and Mitigation Plan

In response to the Attorney General's position that the proposed climate adaptation and mitigation plan reflects only what would otherwise be achieved without a PBR plan, NSTAR Electric reiterates that the objective of the PBR plan is to enable long-term planning that aligns with policy objectives, and that the Company's plan to reduce emissions is consistent with such Commonwealth policy objectives (Company Brief at 122, citing Attorney General Brief at 76; Tr. 7, at 477-478).

NSTAR Electric does not disagree with Cape Light Compact's assertions that LED lighting is industry standard practice, and that the Company will have completed its LED replacements by the end of 2022 (Company Brief at 124, citing Exh. DPU 68-22). NSTAR Electric, however, disagrees that LEDs, as a source of emissions reductions, should be removed from the climate adaption and mitigation plan (Company Brief at 124). The Company argues that it has been transparent about how to achieve its emissions reductions, and if it completes installation of LED bulbs, it will increase reliance on other measures to achieve its emissions reductions (Company Brief at 124-125, citing Cape Light Compact Brief at 34; Company Reply Brief at 19, citing Cape Light Compact Reply Brief at 13; Tr. 5, at 367). Further, NSTAR Electric disagrees with Cape Light Compact's recommendation to include non-LED Rate S-1 lighting in the climate adaption and mitigation plan (Company Brief at 125). According to the Company, including non-LED lighting would result in a cost to ratepayers if completed prior to full depreciation, which is expected in approximately two years, at which point the non-LED lighting would be replaced with LEDs (Company Brief at 125, citing Exh. CLC-ES 2-4; RR-CLC-1).

e. Equity and Electrification Planning Frameworks

NSTAR Electric asserts that additional work is needed to gather information through direct communications with EJ communities, and, therefore, the Company proposed to replace its initially proposed equity index metric with the equity framework (Company Brief at 109, citing Exh. ES-METRICS-Rebuttal-1, at 15). Further, NSTAR Electric contends that by proposing equity and electrification frameworks (as opposed to metrics), the Company will have additional time to work with stakeholders to ensure that future metrics to measure progress on these objectives are robust and consistent with the evolving legislative landscape and regulatory and policy developments (Company Brief at 108, 110-111, citing Exh. ES-METRICS-Rebuttal-1, at 11, 14; RR-DPU-17; RR-DPU-18).

NSTAR Electric disagrees with the Attorney General that by converting the metrics into planning frameworks the Company eliminated substantive measures for equity and electrification (Company Brief at 121, citing Attorney General Brief at 73). NSTAR Electric argues that, although it will not be setting a target, the frameworks still will ensure that the Company consistently takes action to meet equity and electrification objectives (Company Brief at 121). Moreover, NSTAR Electric contends that, in lieu of these metrics, the Company has proposed new metrics not included in the initial filing and a penalty/incentive mechanism (Company Brief at 121). Thus, according to the Company, the conversion of two metrics to frameworks did not diminish the accountability created by the proposed metrics (Company Brief at 121). Finally, NSTAR Electric asserts that the electrification framework ensures that the Company's ten-year planning process is in line with the Commonwealth's All Options pathway and does not encourage overspending, as suggested by the Attorney General (Company Brief at 122, citing Attorney General Brief at 78).

f. MAIFI

In response to TEC and PowerOptions' arguments regarding MAIFI reporting, the Company agrees to report MAIFI data for devices with SCADA visibility, so long as this metric would not be subject to penalties (Company Brief at 124). Further, the Company asserts that following deployment of AMI meters, MAIFI from each customer will be integrated into a momentary outage dashboard (Company Brief at 124, citing DPU 68-7).

D. Analysis and Findings

1. Review Criteria

As discussed in Section IV.D.5.a above, the Department has approved a PBR plan for NSTAR Electric with a five-year term. To measure the full range of benefits that will accrue under the PBR plan, the Department finds that it is appropriate to establish a set of broad performance metrics that are tied to the goals of the PBR plan and are consistent with the Department's regulatory objectives.

2. Proposed Metrics

a. Customer Satisfaction, Customer Engagement, and Operations Metrics

The Company proposes a total of five metrics in the categories of customer satisfaction, customer engagement, and operations. First, the overall customer satisfaction metric utilizes J.D. Power's residential customer satisfaction score (Exh. ES-METRICS-1, at 17). The Department finds that the overall customer satisfaction metric appropriately creates a focus on customer service and that J.D. Power is an appropriate independent source for this information (Exhs. ES-METRICS-Rebuttal-2, at 1; ES-CAH/DPH-1, at 112). As suggested by intervenors, the Department finds that the Company's annual target should be a first quartile ranking instead of a specific numerical score (Attorney General Brief at 70; UMass Brief at 53). This measurement will encourage NSTAR Electric's customer satisfaction to improve at rates above the average pace in the industry. If the Company fails to meet the first quartile ranking, NSTAR Electric should explain the aspect(s) of the score (i.e., a low category score in power quality and reliability, price, billing and payment, communications) that impacted the Company's ability to do so. Further, the Department agrees with the UMass's assertion that the Company's J.D. Power business customer satisfaction ranking also should be reported (UMass Brief at 53). Accordingly, the Department directs the Company to include annual reporting on its J.D. Power business customer satisfaction survey results and to target a first quartile ranking.

Second, the transactional customer satisfaction metric will report the results of a customer survey focused on their satisfaction with the Company's: (1) unplanned outages;

(2) planned outages; (3) website; and (4) the contact center (Exh. ES-METRICS-Rebuttal-1, at 19-20). The Company proposes to incorporate the metric into the SQ penalty framework, with a symmetrical incentive (Exh. ES-METRICS-Rebuttal-1, at 19). NSTAR Electric states that the proposed index, unlike the J.D. Power metric, reduces the effect on customer satisfaction of factors outside of the Company's control, such as rising energy costs or increased demand due to weather (Exh. ES-METRICS-Rebuttal-1, at 19). The Department finds that a customer satisfaction metric that removes the impact of certain energy cost increases that are outside of the Company's control is reasonable and useful, as it focuses more directly on improving specific services to customers. In addition, the Department finds that the interactions upon which customers will be surveyed are reasonable and important for the Company to track and target improvement. For these reasons, the Department approves the Company's transactional customer satisfaction metric. The Department, however, rejects the Company's proposal to incorporate this metric into the SQ penalty framework, as discussed in further detail below.

Third, the customer usage of an outage map metric will track the number of unique views during ERP events and report engagements with the outage map as a percentage of total inbound customer communications during these events, rather than reporting a total count of interactions (Exh. ES-METRICS-1, at 25-26). No intervenors commented on the use of outage map metric. The Department recognizes the benefits to customers of accessing service outage status, expected downtime, and the cause of the outage during ERP events. Accordingly, we approve the Company's use of the outage map metric.

Fourth, the digital engagement metric will measure the percentage of customer interactions that are digital (Exh. ES-METRICS-1, at 27). No intervenors commented on the digital engagement metric. The Department recognizes that customers rely on digital interactions to pay bills, report outages, receive service updates, etc. As such, there are benefits to providing convenient and accessible digital tools to customers and doing so can improve customer experience and education. It stands to reason that tracking the percentage of digital engagements is an important component in this process. Accordingly, the Department approves the Company's digital engagement metric.

Finally, the new customer connects metric is the percentage of new customer connections that meet the target timelines for different types of connections, excluding hold days (Exh. ES-METRICS-1, at 44). The Company is proposing to incorporate this metric into the SQ penalty framework, with a symmetrical incentive (Exhs. ES-METRICS-Rebuttal-1, at 21, 23; ES-METRICS-Rebuttal-2, at 3). No intervenors commented on the new customer connects metric. The Department recognizes the role that electrification will play in meeting the climate goals of the Commonwealth, thus ensuring timely connections for new customers is an important goal. Accordingly, the Department approves the new customer connects metric. We also direct the Company to report data on the number of hold days, and the reason for the hold days. The Department, however, disallows its inclusion in the SQ penalty framework, as discussed in further detail below.

b. Producer Satisfaction and Producer/Developer Engagement Metrics

The Company proposes a total of three metrics in the categories of producer satisfaction and producer/development engagement. The producer satisfaction survey metric will survey interconnecting customers 65 and 365 days after interconnection, and the hosting capacity map usage metric will track the number of hits to the hosting capacity map webpages (Exhs. ES-METRICS-1, at 28-29; ES-METRICS-Rebuttal-2, at 2-3; DPU 42-3). No intervenors commented on these producer satisfaction metrics. The Department acknowledges the increasing role of DER on the electric distribution system. We find that these two metrics are reasonable and appropriate to gauge the services provided to and satisfaction of producers. As such, we allow these metrics.

The third metric is the solar development timeline metric, which will measure the duration from creation of a solar installation work order to completion in business days (excluding hold days), and then will calculate the percentage of solar installations meeting certain timeline performance targets by dividing the number of solar installations that meet the targets by the total number of solar installations (Exhs. ES-METRICS-Rebuttal-1, at 20-21; ES-METRICS-Rebuttal-2, at 3). The Company proposes to incorporate the metric into the SQ penalty framework, with a symmetrical incentive (Exh. ES-METRICS-Rebuttal-1, at 20-21). No intervenors commented on the solar development timeline metric. We recognize the important role that solar power will play in meeting the Commonwealth's energy goals, and that timely connection of solar installations is important component in achieving these goals. Accordingly, the Department approves the

Company’s proposed solar development timeline metric. The Department, however, disallows the metric’s inclusion in the SQ penalty framework, as discussed in further detail below.

c. Incorporation of Three Metrics into SQ Penalty Framework

The Company proposes to incorporate the new customer connects, transactional customer satisfaction index, and the solar development timeline metrics into the Department’s SQ Guidelines (Exhs. ES-METRICS-Rebuttal-1, at 23; ES-METRICS-Rebuttal-2, at 1, 3). The Company also proposes that a symmetrical incentive apply to the PBR metrics that are incorporated into the SQ penalty framework (Exh. ES-METRICS-Rebuttal-1, at 23-24). Several intervenors assert that effective metrics should include incentives and/or penalties (Attorney General Reply Brief at 11-12; DOER Brief at 10, 19-21; Acadia Center Brief at 15; UMass Brief at 52). The Department finds that, in some instances, incentives and penalties are important to the development of meaningful metrics. We recognize, however, that altering the SQ penalty formula may have unintended implications, such as weakening the penalties on existing SQ metrics. Further, the proposal to incorporate these three metrics into the SQ framework was introduced relatively late in the proceeding, and we conclude that the metrics may need refining over time to align the financial incentives with customer benefits. Based on these considerations, we find that the Company’s proposal to incorporate these three metrics into the SQ framework warrants more focused attention. Further, we find it prudent for other stakeholders to have an opportunity to propose different potential methods of incorporating penalties and incentives into these metrics. To advance the effort of developing appropriate PBR incentive and penalty metrics, the Company shall track and report the three metrics, without making the proposed changes to the SQ Guidelines. For developing a baseline and target for the transactional customer satisfaction and solar development timeline metrics, the Company should apply the SQ method for establishing a baseline and a target.[61] As discussed in further detail below, the Department finds that tracking and reporting will inform a continued stakeholder dialog on metrics.

d. Peak Demand Reduction Metric

The Company proposes to track peak demand reductions from six programs and initiatives (Exhs. ES-METRICS-Rebuttal-2, at 4-6; DPU 49-1, at 3-4). Several intervenors contend that the proposed metric does not track the impact of investments enabled by the PBR plan, as the Department directed in D.P.U. 17-05 (Attorney General Brief at 70-71; Attorney General Reply Brief at 13; UMass Brief at 53-54). In D.P.U. 17-05 at 409-410, the Department identified system peak demand reduction as an important objective. We find that the Company's proposed peak demand reduction metric is an appropriate starting point for developing a more advanced system peak reduction metric. In particular, we find that reporting on the proposed peak demand reduction metric will provide important data to facilitate the evaluation of benefits associated with energy efficiency programs, demand response programs, company-owned storage, company-owned solar, upgrades to standard

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[61] NSTAR Electric proposed a baseline and a target based on previous years data for the new customer connects metric, and the Department approves that baseline and target (Exh. ES-METRICS-1, at 45-46).

technologies, and VVO. Based on these considerations, the Department approves this proposed metric. As the Company and stakeholders continue to develop a set of metrics, as discussed below, the parties should consider first whether peak demand reduction is a priority objective, and second, how to develop a robust measure for reductions to system peak demand that are under the Company's control.

e. Climate Adaptation and Mitigation Plan

As noted above, NSTAR Electric proposes to pursue an updated enterprise-wide climate adaptation and mitigation plan, which focuses on bringing renewable energy to the region and reducing the Company's own GHG emissions (Exhs. ES-METRICS-1, at 39; ES-METRICS-2, at 3; DPU 23-2). In particular, the Company proposes to adopt a goal of reducing emissions ten percent from a 2022 baseline by 2027 (Exhs. ES-METRICS-1, at 39-40; ES-METRICS-Rebuttal-2, at 6). The Company states that its proposed metrics are to be designed to create consistency with current Commonwealth policy goals (Exhs. ES-CAH/DPH-1, at 10-11; ES-METRICS-1, at 11). As such, the Company's GHG emissions reduction targets should align with decarbonization objectives in the 2021 Climate Act, and applicable sector-specific interim targets and sub-limits established pursuant to G.L. c. 21N, § 3A. The Company states that it tracks emissions at an enterprise-wide level, including its operating companies in its New Hampshire, Connecticut, and Massachusetts service territories (Exh. DPU 23-2). We conclude, however, that to align with Massachusetts decarbonization goals, it is more appropriate for the Company's emissions reduction goal to reflect GHG emissions and reductions in the Massachusetts service territory only. Similarly, the Company's investments and programs during the PBR term must reflect an appropriate level of climate adaptation. Therefore, while we approve the climate adaption and mitigation plan, we direct the Company in its annual PBR filing to include a demonstration of how the plan is aligned with the objectives of the Commonwealth's decarbonization policies, including applicable sector-specific interim targets and sub-limits established pursuant to G.L. c. 21N, § 3A.

Finally, as discussed above, Cape Light Compact argues that LED lighting replacement should not be included in the Company's climate adaptation and mitigation plan (CLC Brief at 35-36, citing Exhs. ES-METRICS-Rebuttal-1, at 30; CLC-KFG-1, at 13; CLC-KFG-4; Tr. 5, at 366-367; CLC Reply Brief at 13, citing Company Brief at 124). Alternatively, Cape Light Compact asserts that, if the Department approves the Company's climate adaption and mitigation plan with LED lighting replacement included, then it should direct NSTAR Electric to expand its LED replacements to non-LED Rate S-1 (Company-owned) lighting to further reduce GHG emissions (CLC Brief at 33, 36; CLC Reply Brief at 13-14). The Company states that by the end of this calendar year, all Eversource Energy facilities will have undergone a lighting upgrade replacing inefficient fixtures with energy saving LEDs (Exh. DPU 68-22). In addition, the Company reports that it expects non-LED S-1 lighting to be phased out and replaced by LED streetlights in approximately two years (Exh. CLC-ES 2-4). Given these timeframes, the Department finds that it is unnecessary to include LED lighting replacement as part of the climate adaption and mitigation plan. In its annual PBR filings, the Company shall report on its compliance with these timelines; if the Company does not meet these timelines, it shall report on the percentage of S-1 lighting categories of (a) LED and (b) non-LED.

f. Equity and Electrification Planning Frameworks

The Company proposes two planning frameworks through annual reporting, one for equity and one for electrification, applicable to capital investment projects of $20 million or greater and designed to provide commitments to policy objectives and increase transparency (Exh. ES-METRICS-Rebuttal-1, at 10-12, 17). The Attorney General argues that the planning frameworks lack substantive measures and require further examination through a stakeholder process (Attorney General at 73). DOER supports the Department's approval of the frameworks but recommends tracking benefits of the Company's investments in a quantitative manner (DOER Brief at 22).

The Department expects our understanding of how to advance equity as an objective in the oversight of regulated utilities to evolve over time. The Department finds that the proposed framework would benefit from continued development and incorporation of stakeholder feedback to assist in this evolution. The proposed equity framework represents a first step, and is a reasonable and appropriate means, to collect useful data to inform future metrics. As such, the Department approves the equity framework. We note, however, that the Company's compliance with the framework would not necessarily satisfy any obligation to address EJ or other equity issues in proceedings before the Department.

Regarding the proposed electrification framework, the Attorney General contends that the proposal may create a risk of overbuilding and overspending that will be borne by ratepayers, and that the Department should not approve new planning standards ahead of the legislatively mandated process prescribed in the 2022 Clean Energy Act (Attorney General Brief at 74). The Department acknowledges that the Company's planning standards for future bulk station projects have merit, and we recognize that the Company will need to conform with planning criteria that enable a decarbonized future. However, the Legislature's intent is for the comprehensive design and implementation of such standards within the electric sector modernization process outlined in 2022 Clean Energy Act, Section 92B. As such, we decline to approve a prescriptive planning framework related to long-term investments in advance of any legislatively mandated process. Accordingly, we do not approve the Company's electrification framework.

g. Resiliency Metrics and Low-Income Terminations Metric

The Company proposes metrics that were developed based on intervenor feedback, namely two metrics for resiliency (MAIFI and an all-in measure of SAIDI and SAIFI) and a low-income terminations reporting metric (Exhs. ES-METRICS-Rebuttal-1, at 31; LI-ES 2-1; RR-DPU-16; Company Brief at 124, App. A at 7). Intervenors support the approval of the MAIFI-related resiliency metric (DOER Reply Brief at 8-9; TEC/PowerOptions Brief at 12-13) and the low-income terminations metric (DOER Brief at 21; Low-Income Network Letter in Lieu of Reply Brief at 1). No intervenors commented on the all-in measure of SAIDI and SAIFI metric. The Department finds that each of the resiliency metrics and the low-income terminations metric are reasonable, reflects important policy goals, and reports data in a way that promotes transparency. Accordingly, the Department approves the resiliency metrics and the low-income terminations metric.[62]

3. Conclusion

Subject to the findings above, the Department approves the Company's proposed metrics, the proposed equity framework, and the proposed climate adaption and mitigation plan. We deny the Company's proposal to incorporate three proposed metrics into the SQ penalty framework. Further, the Department does not approve the Company's electrification framework. The Department finds that the approved suite of metrics will provide a means of monitoring both the Company's performance and progress toward achieving important policy goals of the Department and the Commonwealth.[63]

The Department appreciates the participation and feedback offered by multiple intervenors. In particular, we acknowledge that several intervenors argued that the Company's metrics would benefit from additional stakeholder feedback, outside of a base distribution rate case proceeding (Attorney General Brief at 65; Attorney General Reply Brief at 13; DOER Brief at 20-21; DOER Reply Brief at 2-3; Cape Light Compact Reply Brief at 13-14; UMass Brief at 48). We recognize that the development of meaningful

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[62] The Department confirms that it is not approving any penalty associated with the MAIFI-related metric (Company Brief at 124).

[63] The metrics approved in this proceeding supersede those presented in D.P.U. 18-50. As no meaningful issues would remain in D.P.U. 18-50 and in the interest of administrative efficiency, the Department will conclude its investigation in D.P.U. 18-50 and close that docket.

performance metrics should not be the sole responsibility of the Company and should involve a broader, more transparent stakeholder process that will benefit from sharing data and assumptions. The Department also acknowledges that some metrics should incorporate financial incentives and consequences. Thus, while the Department is satisfied that the metrics proposed herein should be approved, subject to the findings above, we direct the Company to coordinate an inclusive stakeholder process over the course of the PBR term to continue to refine the metrics approved herein.

The first step of the stakeholder process should be to define a set of guiding objectives. Then, through the stakeholder process, the Company should refine the metrics approved here, as well as develop a narrow set of new metrics, as needed, to arrive at a comprehensive set of metrics that meet the Department's review criteria and that target improvements to the stakeholder group's stated objectives. Finally, while some reporting-only metrics are valuable for monitoring performance and sharing information and data, at least a subset of key metrics should be tied to incentives and penalties. As a general guideline, incentive/penalty mechanisms should be symmetrical.

The Department directs the Company to report on the progress of the metrics development process in the annual PBR filings. Specifically, the Company shall report on the number of stakeholder meetings held, a list of the stakeholders that participated, and meeting agendas and minutes. The Company shall report on any proposed mutually-agreed upon changes to the metrics approved herein, any new metrics, and any areas of disagreement among the stakeholders. The Department will consider the proposed metrics during our review of the annual PBR filings based on the outcomes of the stakeholder process. The Department's expectation is that the Company and relevant stakeholders will reach agreement on a set of meaningful metrics that, if adopted by the Department, will remain in place should the Company decide to request an extension of the PBR plan term (see Section IV.D.5.a above). To the extent that NSTAR Electric seeks to continue the PBR plan approved herein after the five-year term expires, it shall submit a proposal that lists and defines the metrics that the Company and stakeholders have developed, reports on all other proposals that were considered, and summarizes the final positions of stakeholders on each metric. If the metrics are quantitative, the metrics may include symmetrical incentives and penalties for Department consideration. This proposal shall be filed at least six months in advance of the end of the PBR plan term.

Finally, the Department will consider opening a generic proceeding to direct the development of a common set of electric utility metrics or guidelines, by which future PBR plans can be guided. If a generic proceeding is opened, the Department may modify the foregoing directives relative to NSTAR Electric's stakeholder process.

VI. RATE BASE

A. Introduction

As of December 31, 2021, NSTAR Electric had a rate base of $4,286,717,212 (Exh. ES-REVREQ-2, Sch. 29 (Rev. 4)). From this amount, the Company subtracted

$191,528,926 to remove grid modernization, Solar Program investments,[64] and the associated deferred income tax for a total proposed rate base of $4,095,188,286 (Exh. ES-REVREQ-2, Sch. 29 (Rev. 4)).[65] NSTAR Electric's total proposed rate base consists of: (1) $5,304,246,946 in net utility plant in service; (2) $57,121,673 in materials and supplies; and (3) $54,964,283 in cash working capital, less (1) $744,331,898 in accumulated deferred income taxes ("ADIT"); (2) $532,319,565 in net FAS 109 regulatory liabilities; and (3) $44,493,152 in customer deposits and advances (Exh. ES-REVREQ-2, Sch. 29 (Rev. 4)).

B. Plant Additions

1. Introduction

As of December 31, 2021,[66] NSTAR Electric proposes a utility plant in service balance of $7,900,933,940 (Exh. ES-REVREQ-2, Sch. 29 (Rev. 4)). The reserve for depreciation balance as of the same date was $2,596,686,994, yielding a net plant balance of $5,304,246,946 (Exh. ES-REVREQ-2, Sch. 29 (Rev. 4)).

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[64] The Company removed Solar Program costs associated with the former WMECo's solar facilities pursuant to G.L. c. 164, § 1A(f), as added by the Green Communities Act, and approved in a stipulation agreement in Western Massachusetts Electric Company, D.P.U. 09-05 (2009) (see n.165 below). The Department has allowed inclusion in rate base of the Solar Expansion Program investments, pursuant to our findings in Section XIV.B.4 below.

[65] NSTAR Electric's pro forma adjustment includes a decrease of $201,017,135 in net utility plant less $9,488,209 in accumulated deferred income taxes (Exh. ES-REVREQ-2, Sch. 29 (Rev. 4)).

[66] In Section IV.D.5.e above, the Department approved NSTAR Electric's proposal to include the Company's 2021 plant additions in rate base without regard to the size of the plant additions in relation to rate base.

2. Project Documentation

NSTAR Electric manages its capital authorization process in accordance with a project authorization policy (Exhs. ES-ADDITIONS-1, at 16; ES-ADDITIONS-11). The project authorization policy sets forth classifications based on the size and nature of a project and sets documentation requirements for each classification (Exh. ES-ADDITIONS-11E at 121-124). Specific projects are those that exceed or are expected to exceed certain cost thresholds (Exh. ES-ADDITIONS-11E at 121).[67] Each specific project requires a project authorization form, which includes: (1) a project description and objectives; (2) a scope and justification; (3) a financial evaluation; (4) a risk assessment; (5) alternatives considered; (6) a technology assessment (for information system projects only); (7) a project schedule; (8) project milestones; and (9) an implementation plan (Exh. ES-ADDITIONS-1, at 16-17). Annual programs, also known as blanket programs, consist of projects and work orders that are similar, small, or routine capital jobs performed over the course of a year with costs below the specific project thresholds (Exhs. ES-ADDITIONS-1, at 13; ES-ADDITIONS-11E,

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[67] For most distribution operations projects placed in service between 2016 and 2021, the specific project threshold is $100,000 in direct costs. For distribution operations projects placed in service between 2016 and 2017 in WMA, however, the threshold is $100,000 in total costs. For transmission and shared services projects, the specific project threshold is $500,000 (Exh. ES-ADDITIONS-1, at 34). Effective January 1, 2022, the Company increased the specific project threshold for all distribution operations projects from $100,000 in direct costs to $500,000 in total costs, aligning the requirements of distribution, transmission, and shared services projects (Exhs. ES-ADDITIONS-1, at 20; ES-ADDITIONS-11F at 154). The project authorization form threshold change does not pertain to any capital additions proposed for inclusion in rate base in this proceeding.

at 121). One project authorization form is prepared for the projects under an annual program (Exh. ES-ADDITIONS-11E, at 121).

For the purposes of documentation provision, NSTAR Electric provided several listings of its capital additions, including: (1) a summary of its total capital additions by year; (2) NSTAR Electric's plant in service by year reconciled to the respective FERC Form 1 accounts; and (3) a chronological list of all NSTAR Electric projects and work orders for specific projects with direct charges over $100,000 and blanket work orders/programs, which includes cost estimates, revised estimates, actual direct costs, and cost variances (Exhs. ES-ADDITIONS-1, at 30-32; ES-ADDITIONS-2 & Supp.; ES-ADDITIONS-3 (East) & Supp.; ES-ADDITIONS-3 (West) (Rev.) & (Supp.); ES-ADDITIONS-4 (East) & Supp.; ES-ADDITIONS-4 (West) & Supp.). The Company further organizes its plant additions into the project classifications that reflect distinct documentation requirements, including: (1) specific projects with direct charges over $100,000; (2) blanket work orders/programs with direct charges over $100,000; (3) specific projects over $50,000; (4) blanket programs over $50,000; (5) specific projects under $50,000; (6) blanket work orders and programs under $50,000; and (7) shared services and transmission projects with total costs over $500,000 (Exh. ES-ADDITIONS-1, at 27). To support the costs of the capital additions included in these listings, the Company provided copies of the project authorization forms, supplemental project authorization forms,[68] variance analyses, delegate of authority approvals, and closing reports (Exhs. ES-ADDITIONS-1, at 33; ES-ADDITIONS-5 & Supp.).

3. Positions of the Parties

The Company argues that it has properly supported the net plant-in-service through December 31, 2021, with actual computations and thousands of pages of supporting documentation (Company Brief at 292). According to the Company, the supporting documentation includes project cover sheets, approved amounts, actual costs, cost variance information, and closure papers (Company Brief at 292, citing Exhs. ES-ADDITIONS-1, at 30-33; ES-ADDITIONS-4 (East) and (West) & Supps.; ES-ADDITIONS-5 & Supp.; ES-ADDITIONS-7 & Supp.; ES-ADDITIONS-12(b)). NSTAR Electric contends that the record demonstrates that the Company's capital additions submitted for approval in this case are prudently incurred and used and useful in providing service to customers (Company Brief at 292). Additionally, the Company argues that its capital budgeting and authorization process assures cost containment (Company Brief at 294, citing Exh. ES-ADDITIONS-1, at 12-18). Thus, NSTAR Electric asserts that its capital projects through December 31,

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[68] The Company requires supplemental project authorization forms when project costs exceed or are expected to exceed the initially authorized budgeted amount by thresholds set based on the size of the project (Exh. ES-ADDITIONS-1, at 17-18).

2021, should be included in rate base (Company Brief at 300). No other party commented on the prudence of NSTAR Electric's plant additions on brief.[69]

4. Standard of Review

For costs to be included in rate base, the expenditures must be prudently incurred, and the resulting plant must be used and useful to ratepayers. Western Massachusetts Electric Company, D.P.U. 85-270, at 20 (1986). The prudence test determines whether cost recovery is allowed at all, while the used and useful analysis determines the portion of prudently incurred costs on which the utility is entitled to a return. D.P.U. 85-270, at 25-27.

A prudence review involves a determination of whether the utility's actions, based on all that the utility knew or should have known at that time, were reasonable and prudent in light of the extant circumstances. Such a determination may not properly be made on the basis of hindsight judgments, nor is it appropriate for the Department merely to substitute its own judgment for the judgments made by the management of the utility. Attorney General v. Department of Public Utilities, 390 Mass. 208, 229-230 (1983). A prudence review must be based on how a reasonable company would have responded to the particular circumstances and whether the company's actions were in fact prudent in light of all circumstances that were known, or reasonably should have been known, at the time a decision was made. Boston Gas Company, D.P.U. 93-60, at 24-25 (1993); D.P.U. 85-270, at 22-23; Boston

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[69] In Section XIV.A.3 and XIV.B.3 below, we address the Attorney General's position concerning NSTAR Electric's proposal to include costs in rate base associated with the Company's SMART Program and Solar Expansion Program investments.

Edison Company, D.P.U. 906, at 165 (1982). A review of the prudence of a company's actions is not dependent upon whether budget estimates later proved to be accurate but rather upon whether the assumptions made were reasonable, given the facts that were known or that should have been known at the time. Massachusetts-American Water Company, D.P.U. 95-118, at 39-40 (1996); D.P.U. 93-60, at 35; Fitchburg Gas and Electric Light Company, D.P.U. 84-145-A at 26 (1985).

The Department has cautioned utility companies that, as they bear the burden of demonstrating the propriety of additions to rate base, failure to provide clear and cohesive reviewable evidence on rate base additions increases the risk to the utility that the Department will disallow these expenditures. Massachusetts Electric Company, D.P.U. 95-40, at 7 (1995); D.P.U. 93-60, at 26; The Berkshire Gas Company, D.P.U. 92-210, at 24 (1993); Metropolitan District Commission v. Department of Public Utilities, 352 Mass. 18, 24 (1967). In addition, the Department has stated that:

> In reviewing the investments …that were made without a cost benefit analysis, the [c]ompany has the burden of demonstrating the prudence of each investment proposed for inclusion in rate base. The Department cannot rely on the unsupported testimony that each project was beneficial at the time the decision was made. The [c]ompany must provide reviewable documentation for investments it seeks to include in rate base.

D.P.U. 92-210, at 24.

5. Analysis and Findings

To demonstrate its cost control efforts, NSTAR Electric provided information regarding its capital planning and authorization process and project documentation, which included the Company's current and previous project authorization policies and corresponding levels of documentation by project type and dollar threshold, as described above (Exhs. ES-ADDITIONS-1, at 32; ES-ADDITIONS-5). In addition, the Company responded to several Department information requests seeking more information on and clarification of the supporting documentation (e.g., Exhs. DPU 6-1 through DPU 6-10; DPU 17-1 through DPU 17-8; DPU 47-1 through DPU 47-9). Further, in addition to maintaining the project documentation required by the project authorization policy, the Company's project managers review invoices and labor costs charged to projects monthly to ensure that all associated costs are properly charged and senior management reviews the scope, size, design, and status of each ongoing project monthly (Exhs. ES-ADDITIONS-1, at 22-25; AG 9-4).

Based on our review of the Company's testimony, policies, and documentation, the Department finds that NSTAR Electric's cost control measures were reasonable and appropriate.[70] In addition, the record evidence demonstrates that the project costs associated with the Company's plant additions through December 31, 2021, were prudently incurred and

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[70] As noted above, the Company revised its project authorization form threshold for specific projects from $100,000 in direct costs to $500,000 in total costs effective January 1, 2022. As there are no project costs subject to the new policy included in the Company's rate base and, therefore, no basis in this proceeding upon which to consider the impact of the Company's policy change, nothing in this Order shall be construed as a finding or determination on the reasonableness or appropriateness of the revised project authorization form threshold. The Department cautions NSTAR Electric that, while its project authorization form threshold has increased, projects of lower values remain subject to scrutiny and the requirement that a company maintain adequate documentation to support the prudence of its capital additions. D.P.U. 14-150, at 54-55.

the resulting plant additions are used and useful in providing service to ratepayers. As such, the Department allows these investments in the Company's plant in service.

6. Conclusion

Based on our findings above, the Department finds that the costs of NSTAR Electric's plant additions were prudently incurred, and the resulting plant is used and useful in providing service to the Company's customers. The Department allows a net plant balance of $5,095,400,897. The allowed net plant balance reflects adjustments pursuant to Section XV.C.2 below and is shown on Schedule 4 below.

C. Cash Working Capital Allowance

1. Introduction

The purpose of conducting a cash working capital lead-lag study is to determine a company's "cash in-cash out" level of liquidity in order to provide the company an appropriate allowance for the use of its funds. Western Massachusetts Electric Company, D.P.U. 87-260, at 22-23 (1988). Such funds are either generated internally or through short-term borrowing. See D.P.U. 96-50 (Phase I) at 26. Department policy permits a company to be reimbursed for costs associated with the use of its funds and for the interest expense incurred on borrowing. D.P.U. 96-50 (Phase I) at 26; D.P.U. 87-260, at 22. The Department requires all electric and gas companies serving more than 10,000 customers to conduct a fully developed and reliable O&M lead-lag study. Fitchburg Gas and Electric Light Company, D.P.U. 11-01/D.P.U. 11-02, at 164 (2011). In the event that the lead-lag factor is not below 45 days, a company will face a high burden to justify the reliability of such a study and the reasonableness of the steps the company has taken to minimize all factors affecting cash working capital requirements within its control, such as the collections lag. D.P.U. 11-01/D.P.U. 11-02, at 164.

2. Company Proposal

NSTAR Electric conducted a lead-lag study to determine its cash working capital requirements (Exhs. ES-REVREQ-1, at 147; ES-REVREQ-5). Consistent with the lead-lag study approved in D.P.U. 17-05, at 121, the cash working capital associated with purchased power expense will be recovered through the Company's basic service cost adjustment provision, and the cash working capital associated with other operating expenses will be recovered through inclusion in the Company's rate base (Exh. ES-REVREQ-1, at 147). Each component uses revenue lag days and expense lead days to determine the cash working capital requirement (Exh. ES-REVREQ-1, at 148). NSTAR Electric conducted its lead-lag study using in-house personnel to update the net lag days associated with each component of its proposed cash working capital allowance (Exh. ES-REVREQ-1, at 147-156).

NSTAR Electric calculated a revenue lag to be used in both the O&M and basic service cash working capital net lag factors. The revenue lag consists of a "meter reading or service lag," "collection lag," and a "billing lag" (Exh. ES-REVREQ-1, at 149). The sum of the days associated with these three lag components is the total revenue lag experienced by NSTAR Electric (Exh. ES-REVREQ-1, at 149). NSTAR Electric calculated a meter reading or service lag of 15.21 days (Exhs. ES-REVREQ-1, at 149; ES-REVREQ-5, Sch. WC-2, at 1). This lag was derived by dividing the number of billing days in the test year by twelve months and then in half to arrive at the midpoint of the monthly service periods (Exhs. ES-REVREQ-1, at 149; ES-REVREQ-5, Sch. WC-2, at 1). The collection lag, which reflects the time delay between the mailing of customer bills and the receipt of the billing revenues from customers, totaled 26.00 days (Exhs. ES-REVREQ-1, at 149-150; ES-REVREQ-5, Sch. WC-2, at 1). The collection lag was obtained by dividing the average daily accounts receivable balance by the average daily revenue amount to arrive at the collection lag (Exhs. ES-REVREQ-1, at 150; ES-REVREQ-5, Sch. WC-2, at 1). Finally, NSTAR Electric applied a billing lag of one day, based on the fact that most of its customers are billed the day after meters are read (Exhs. ES-REVREQ-1, at 150; ES-REVREQ-5, Sch. WC-2, at 1).[71] Based on the foregoing, NSTAR Electric calculated a total revenue lag of 42.21 days by adding the number of days associated with each of the three revenue lag components (Exhs. ES-REVREQ-1, at 151; ES-REVREQ-5, Sch. WC-2, at 1).

NSTAR Electric's O&M cash working capital is comprised of O&M expense, payroll taxes, and property taxes (Exh. ES-REVREQ-1, at 152). NSTAR Electric pays these expenses to finance the activities conducted in service to customers before the Company receives payment from customers for those services (Exh. ES-REVREQ-1, at 152). To calculate the O&M expense lead period, NSTAR Electric disaggregated its O&M expense into eight major cost categories: net payroll; regulatory commission expenses; corporate insurance; other O&M; property taxes; FICA & Medicare; federal unemployment tax; and

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[71] NSTAR Electric made no adjustment in the lead-lag study to account for customers for which additional time is required to process bills (Exh. ES-REVREQ-1, at 150).

state unemployment tax (Exhs. ES-REVREQ-1, at 153; ES-REVREQ-5, Sch. WC-4). NSTAR Electric reviewed test-year payments and calculated the lead days for each category based on either all payments or a sampling of payments (Exh. ES-REVREQ-1, at 153). Once NSTAR Electric determined lead days for each category, it used the sum of the lead days weighted by dollars to arrive at an O&M expense lead of 9.27 days (Exh. ES-REVREQ-5, Sch. WC-4). NSTAR Electric then subtracted the expense lead of 9.27 days from the revenue lag of 42.21 days to produce a net O&M expense lag of 32.95 days (Exhs. ES-REVREQ-1, at 155; ES-REVREQ-5, Sch. WC-1). NSTAR Electric derived an O&M expense cash working capital factor of 9.03 percent by dividing the net lag days of 32.95 by 365 days (Exh. ES-REVREQ-5, Sch. WC-1). The Company multiplied this factor by the total costs applicable to cash working capital[72] of $608,860,793 to calculate a cash working capital allowance of $54,964,283 (Exhs. ES-REVREQ-1, at 155; ES-REVREQ-2, Sch. 34 (Rev. 4)).

3. Positions of the Parties

On brief, NSTAR Electric summarizes its lead-lag study calculations and cash working capital requirements and asserts that the Company's calculations are consistent with Department precedent (Company Brief at 139-141). No other party addressed NSTAR Electric's proposed cash working capital calculations.

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[72] These costs are comprised of total O&M expense, less uncollectible accounts, plus taxes other than income taxes (Exh. ES-REVREQ-2, Sch. 34 (Rev. 4)).

4. Analysis and Findings

The Department has reviewed the evidence in support of NSTAR Electric's lead-lag study, and we conclude that NSTAR Electric properly calculated the total revenue lag of 42.21 days to be applied to both the O&M and basic service expense leads (Exhs. ES-REVREQ-1, at 151; ES-REVREQ-5(a), Sch. WC-2, at 1). Further, the Department finds that NSTAR Electric properly calculated the O&M expense lead of 9.27 days and the resulting net lag of 32.95 days (Exhs. ES-REVREQ-1, at 155; ES-REVREQ-5(a), Schs. WC-1, WC-4). NSTAR Electric's proposed O&M net lag factor of 32.95 days is lower than the Department's 45-day convention (Exhs. ES-REVREQ-1, at 155; ES-REVREQ-5(a), Sch. WC-1). Additionally, we find that NSTAR Electric's decision to perform a lead-lag study with in-house personnel was a cost-effective means to determine its cash working capital requirement (Exh. ES-REVREQ-1, at 147). See Bay State Gas Company, D.P.U. 12-25, at 97 (2012). For these reasons, the Department accepts NSTAR Electric's lead-lag study and the resulting O&M cash working capital factor of 9.03 percent (32.95 days/365 days).

Application of the O&M cash working capital factor of 9.03 percent to the level of O&M and taxes other than income tax expense authorized by this Order produces a cash working capital allowance of $51,347,443. The derivation of this cash working capital allowance is provided in Schedule 6 of this Order.

D. Accumulated Deferred Income Taxes

1. Introduction

NSTAR Electric proposes an ADIT balance of $744,331,898, comprising its total ADIT balance of $1,266,840,909, less: (1) $513,020,802 in ADIT associated with transmission service; (2) $4,368,022 in ADIT related to grid-modernization-related investments; and (3) $5,120,187 in ADIT associated with solar investments at the end of 2021 (Exh. ES-REVREQ-2, Sch. 1, at 4, Sch. 32 (Rev. 4)).[73]

The Company's proposed ADIT balance includes property- and non-property-related ADIT (Exhs. ES-REVREQ-3, WP 32 (Rev. 4); AG 4-4; AG 24-3). Initially, the Company's non-property-related ADIT included a debit balance of $19,268,711 in ADIT associated with what the Company identifies as "other pension expense" (Exhs. AG 13-8; AG 21-6). Of this amount, $3,435,606 was associated with accelerated pension contributions; $298,750 was associated with transmission-related pension expense; ($6,123) was associated with amortization of plan loss; and $15,540,478 was associated with a reclassification of property- and non-property-related ADIT that the Company represents was required for financial reporting purposes in compliance with Accounting Standards Update ("ASU") 2017-07 (Exhs. ES-RR/CCP/Comp-Rebuttal-1, at 38; AG 21-6; Tr. 1, at 122-124).

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[73] In its initial filing, NSTAR Electric proposed an ADIT balance of $733,301,500 based on an adjusted test-year-end balance that included ADIT associated with estimated plant additions during 2021 (Exhs. ES-REVREQ-1, at 146; ES-REVREQ-2, Sch. 1, at 4, Sch. 32). During the proceeding, NSTAR Electric updated all of its rate base line items to reflect balances as of December 31, 2021 (Exh. ES-REVREQ-2, Sch. 1, at 4, Sch. 32 (Rev. 1)).

The Company subsequently revised its proposed "other pension expense" ADIT debit balance amount from $19,268,711 to $3,605,623 by removing the reclassified amount of $15,540,478 from the calculation and revising the remaining amounts as follows: $3,509,996 associated with accelerated pension contributions; $103,087 associated with transmission-related pension expense; and ($7,460) associated with amortization of plan loss (Exh. AG 24-5).

2. Positions of Parties

a. Attorney General

The Attorney General contends that the Company has not explained why its ADIT balances associated with "other pension expense" should be included in rate base and, therefore, did not justify including in rate base the proposed debit balance of $3,509,996 in ADIT associated with accelerated pension contributions (Attorney General Brief at 181-183, citing Exhs. ES-RR/CPP/Comp-Rebuttal-1, at 38; AG 21-6; AG 24-5; Attorney General Reply Brief at 46-47).[74] The Attorney General argues that related to "other pension expense" ADIT should be excluded from rate base, and she calculates a rate base adjustment of $2,448,102[75] based on the Company's allocation to its distribution operations (Attorney

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[74] The Attorney General pointed out that the only significant remaining item to decrease the Company's proposed ADIT is $3,509,996 while the rest of the items are either eliminated after her recommended adjustment or are immaterial (Attorney General Reply Brief at 47).

[75] In her rebuttal testimony, Attorney General calculated the adjustment as $2,361,907 (Exh. AG-DJE-Surrebuttal-1, Sch. DJE-3S).

General Brief at 181-183, <u>citing</u> Exhs. AG-DJE-1, at 12-14; AG 24-5; Attorney General Reply Brief at 46-47).

In support of her position, the Attorney General contends that while NSTAR Electric initially proposed the inclusion of $15,540,478 in its “other pension expense” balance based on the requirements of ASU 2017-07, the Company properly removed it, but still did not sufficiently explain the remaining ADIT items associated with “other pension expense” (Attorney General Brief at 182, <u>citing</u> Exhs. ES-RR/CPP/Comp-Rebuttal-1, at 38; AG 24-5; Attorney General Reply Brief at 47). More specifically, the Attorney General asserts that NSTAR Electric does not attempt to explain or justify the inclusion in rate base of the remaining $3,509,996 “other pension expense” associated with accelerated pension contributions, and instead offers what the Attorney General considers to be an irrelevant description of the elements of its pension adjustment mechanism (“PAM”) (Attorney General Reply Brief at 47 & n. 24). According to the Attorney General, the list of PAM elements is irrelevant to the issue of whether it is appropriate to include in rate base the ADIT related to accelerated pension contributions (Attorney General Reply Brief at 47 & n. 24).

b. <u>Company</u>

The Company argues that it adequately explained that the remaining ADIT items related to other pension expense are not recovered through the PAM, and, therefore, these items are appropriately included in the base distribution ADIT (Company Brief at 221-222, <u>citing</u> Exhs. AG 21-6; AG 24-5; Tr. 1, at 122-125; Company Reply Brief at 64). First, regarding the $3,509,996 in ADIT associated with accelerated pension contribution, the

Company contends that it does not recover contributions to the pension plan through the PAM, and instead, it recovers only actual pension and PBOP O&M-related costs (Company Brief at 222, citing Exhs. ES-RDC-6, Sch. 2; AG 24-5). Further, the Company claims that because it recovers carrying charges on the pension and PBOP prepaid or liability balances net of deferred taxes through the PAM, pension-related contributions are not recoverable through the PAM (Company Brief at 222; Company Reply Brief at 64). In addition, NSTAR Electric asserts that because a portion of its pension and PBOP costs are capitalized, there would be an associated ADIT included in rate base (Company Brief at 221, citing Tr. 1, at 122-125).

Next, the Company argues that the amount of ADIT related to "amortization of plan losses" is included in base distribution ADIT because it is not recovered through the PAM (Company Brief at 222; Company Reply Brief at 65). Finally, the Company asserts that amounts attributable to "transmission" represent unadjusted test-year amounts that are further adjusted in its revenue requirement workpapers (Company Brief at 221-222, citing Exh. ES-REVREQ-3, WP 32, Cols. (F), (H); Company Reply Brief at 65). Therefore, NSTAR Electric contends that its transmission-related ADIT would be adjusted twice if the Department adopts the Attorney General's recommended adjustment (Company Brief at 222; Company Reply Brief at 65).

3. Analysis and Findings

Deferred income taxes arise because of the differences between the tax and book treatment of certain transactions, including the use of accelerated depreciation and the treatment of certain operating expenses for income tax purposes. Fitchburg Gas and Electric Light Company, D.T.E. 99-118, at 33 (2001); Essex County Gas Company, D.P.U. 87-59, at 27 (1987). This difference accumulates and becomes a source of interest-free funds provided by ratepayers and available to the utility to further invest until it is needed to fund the taxes due and payable in the later years. Therefore, ADIT represents an offset to rate base. D.P.U. 87-59, at 63; AT&T Communications of New England, D.P.U. 85-137, at 31 (1985); Boston Edison Company, D.P.U. 1350, at 42-43 (1983); Boston Edison Company, D.P.U. 18200, at 33-34 (1975).

Regarding the Company's revised "other pension expense" ADIT debit balance, if an expense has been deferred on the utility's books and ratepayers were not burdened with the costs, the expense does not exist for ratemaking purposes. Commonwealth Electric Company, D.P.U. 89-114/90-331/91-80 (Phase One) at 24-30 (1991); Massachusetts Electric Company, D.P.U. 89-194/195, at 66 (1990). As such, merely categorizing the deferred income taxes as "other pension expenses" that are not recovered through the PAM does not automatically justify their inclusion in the Company's distribution-related rate base. Therefore, in this instance, the Department examines each item associated with the Company's reported other pension expense ADIT debit balance.

First, the Department finds that the Company has appropriately excluded the debit balance of $103,087 in transmission-related other pension expense ADIT from its proposed ADIT (Exhs. ES-REVREQ-3, WP 32 (Rev. 4); AG 24-5). Next, the Department examines the amortization of pension plan loss related ADIT balance of ($7,460) (Exh. AG 24-5).

According to the Company's annual returns filed to the Department, NSTAR Electric's defined pension costs are accounted for in accordance with accounting guidelines, and this treatment is consistent with the Department-approved PAM (Exh. AG 1-2, Att. (1)(d) at 100).[76] Moreover, this liability or asset is remeasured annually and amortized as the actuarial gains and losses and net periodic benefit cost for the pension, which is consistent with the provisions set forth in the PAM (Exh. AG 1-2, Att. (1)(d) at 100). See NSTAR Electric Company and NSTAR Gas Company, D.P.U. 21-132 (2021). The financial statements of the Company's Annual Returns filed with the Department also note that the unamortized portion of above-mentioned liability or asset is amortized through accumulated other comprehensive income to "Other Income" (Exh. AG 1-2, Att. (1)(d) at 134). The record also shows that the Company recorded the net deferred tax asset as of December 31, 2020 (Exh. AG 1-2, Att. (1)(d) at 134). Through this reclassification process, the Company recognizes the defined pension plan related gain or loss annually. In addition, the record shows that NSTAR Electric recorded other income increase of $5.8 million in 2020 and $10.9 million in 2021 from PAM (Exh. AG 1-2, Att. (1)(d) at 60; AG 1-2 (Supp.), Att. (1)(d) at 61). Moreover, the PAM increases the Company's overall earnings for financial reporting purposes though increasing "Other Income" to meet its pension obligation

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[76] Specifically, the liability or asset recorded to recognize the funded status of the Company's retiree benefit plans is offset by a regulatory asset or liability in the case of a benefit plan asset in lieu of a charge to Accumulated Other Comprehensive Income/(Loss), reflecting ultimate recovery from customers through rates (Exh. AG 1-2, Att. (1)(d) at 134).

(Exh. AG 1-2, Att. (1)(d) at 45, 57). Based on the evidence discussed above, there is insufficient information to support the pension plan loss ADIT (Exh. AG 1-2, Att. (1)(d)). Further, the Company neither explained its pension plan loss nor provided justification for inclusion of other pension expense ADIT in rate base ADIT other than it is not recovered through the PAM (Exhs. AG 21-6; ES-RR/CPP/Comp-Rebuttal-1, at 38; Tr. 1, at 122). Therefore, the Department declines to include the ADIT for pension plan loss in the Company's ADIT balance.

Finally, the Department addresses whether the ADIT debit balance of $3,509,996 associated with accelerated pension contributions should be included in rate base. According to the Company, the reason this ADIT balance needs to be included in rate base is because it is not recoverable in the PAM (Exhs. AG 21-6; Company Brief at 222). The Company, however, has not explained the costs associated with accelerated pension contributions that appear in the record in this proceeding (Exhs. AG 21-6; AG 24-5; Tr. 1, at 122).[77] While the label "accelerated pension contributions" suggests increased amount of pension contributions, it does not provide the reason in context such as the triggers of these accelerated payments and whether they are burdens of the customers. Therefore, the Department finds that the Company has not provided clear and cohesive reviewable evidence

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[77] For example, the Company provided information about accelerated share-based compensation and provided the ADIT amount attributable to the CEO and CFO who were vested as of January 1, 2021, according to the Company's long-term incentive plan (RR-DPU-25 & Att.). The Company could have provided similar information on its executive pension contributions policies to support its proposed accelerated pension contributions ADIT.

to support the ADIT associated with accelerated pension contributions. In proceedings brought under G.L. c. 164, § 94, the petitioning utility bears the burden of proof by presenting a clear and reasonable analysis. D.T.E. 99-118, at 7, citing Fryer v. Department of Public Utilities, 374 Mass. 685, 690 (1978); Fitchburg Gas and Electric Light Company v. Department of Public Utilities, 375 Mass. 571, 578-579 (1978); see also Metropolitan District Commission, 352 Mass. 18, 24.[78] Therefore, the Department disallows the inclusion of ($7,460) associated with the accelerated pension contributions in the Company's ADIT balance.

Based on the evidence, the ADIT amounts reviewed above are the unadjusted balance at the end of 2021 (Exhs. ES-REVREQ-3, WP 32 (Rev. 4); AG 4-4; AG 4-5; AG 13-8; AG 24-3; AG 24-4; AG 24-5). The unadjusted disallowance totals $3,502,536 (i.e., $3,509,996 + ($7,460)). The Department will derive the representative amount of this total attributable to transmission expense (Exh. ES-REVREQ-3, WP 32 (Rev. 4)). This is accomplished by taking the rate-year total non-property rate base ADIT of $102,452,015, divided by the total adjusted test-year ADIT of $129,108,171 to derive a factor of 79.35 percent reflecting the portion of ADIT net of that related to transmission

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[78] The burden of proof is the duty imposed upon a proponent of a fact whose case requires proof of that fact to persuade the factfinder that the fact exists or, where a demonstration of non-existence is required, to persuade the factfinder of the non-existence of that fact. D.T.E. 03-40, at 52; D.T.E. 01-56-A at 16; D.T.E. 99-118, at 7.

(Exh. ES-REVREQ-3, WP 32 (Rev. 4)).[79] Based on the above, the unadjusted disallowance total of $3,502,536 multiplied by the factor of 79.35 percent, results in an adjusted disallowance amount of $2,779,262. Accordingly, the Department increases the Company's rate base ADIT by $2,779,262.

VII. OPERATION AND MAINTENANCE EXPENSES

A. Employee Compensation and Benefits

1. Introduction

When determining the reasonableness of a company's employee compensation expense, the Department reviews the company's overall employee compensation expense to ensure that its compensation decisions result in a minimization of unit-labor costs. Boston Gas Company, Essex Gas Company, and Colonial Gas Company, D.P.U. 10-55, at 234 (2010); D.P.U. 96-50 (Phase I) at 47; Cambridge Electric Light Company, D.P.U. 92-250, at 55 (1993). This approach recognizes that the different components of compensation (e.g., wages and benefits) are, to some extent, substitutes for each other and that different combinations of these components may be used to attract and retain employees. D.P.U. 92-250, at 55. In addition, the Department requires a company to demonstrate that its total unit-labor cost is minimized in a manner supported by its overall business strategies. D.P.U. 92-250, at 55.

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[79] The total adjusted test-year ADIT is derived from the unadjusted test-year amount minus the non-rate base ADIT (Exh. ES-REVREQ-3, WP 32, Cols. (D), (E), (H) (Rev. 4)).

A company is required to provide a comparative analysis of its compensation expenses to enable a determination of reasonableness by the Department. D.P.U. 96-50 (Phase I) at 47. The Department evaluates the per-employee compensation levels, both current and proposed, relative to the companies in the utility's service territory and utilities in the region that compete for similarly skilled employees. D.P.U. 96-50 (Phase I) at 47; D.P.U. 92-250, at 56; Bay State Gas Company, D.P.U. 92-111, at 103 (1992); Massachusetts Electric Company, D.P.U. 92-78, at 25-26 (1992).

NSTAR Electric's employee compensation program is based on a total rewards philosophy and includes base pay, variable compensation, and employee benefits (Exh. ES-SL-1, at 3-6). During the test year, NSTAR Electric booked $164,257,262 net of capitalization in payroll expense for union and non-union personnel, including base wages of $144,810,736 and overtime pay of $19,446,526 (Exh. ES-REVREQ-2, Sch. 10, at 4-5 (Rev. 4)). After a normalization adjustment and removal of transmission-related costs, the Company proposed a total test-year adjusted union and non-union payroll expense of $144,958,862 (Exh. ES-REVREQ-2, Sch. 10 (Rev. 4)). NSTAR Electric proposes to increase its union and non-union payroll expense by $13,138,311, which is net of a rate-year transmission increase allocation of $1,772,843 (see Exh. ES-REVREQ-2, Sch. 10 (Rev. 4)).

2. Non-Union Wages

a. Introduction

NSTAR Electric proposes to increase the test-year adjusted non-union payroll expense based on: (1) a non-union wage increase of three percent effective April 1, 2021; (2) a non-union wage increase of three percent effective April 1, 2022; and (3) a non-union wage increase of three percent effective April 1, 2023 (Exhs. ES-SL-1, at 12; ES-REVREQ-2, Sch. 10, at 3, 4 (Rev. 4)).

The Company determined its non-union wage increases based on a comparative analysis of non-union base salaries and total compensation against median base salaries and total compensation in the energy/utility and general industry sectors in the Northeast, using studies performed by Towers Watson (Exhs. ES-SL-1, at 13-16; ES-SL-5; ES-SL-6). The Company also analyzed whether its actual and proposed merit wage increases were in line with the market by surveying the actual and projected wage increases in the energy/utility and general industry sectors (Exhs. ES-SL-1, at 14, 23; ES-SL-7). In addition, the Company provided a historical comparison of non-union base wage increases to union base wage increases (Exhs. ES-SL-1, at 21; ES-SL-5).

b. Positions of the Parties

NSTAR Electric asserts that its non-union employees' compensation costs are reasonable because the Company establishes the base pay for each position in NSTAR Electric and ESC against similar jobs at other employers in the same competitive market (Company Brief at 225, citing Exhs. ES-SL-1, at 10; ES-SL-5; ES-SL-6; ES-SL-7). The Company claims to set the base pay range between 90 percent and 110 percent of the median market rate for its managers to differentiate base compensation among employees with varied skills, experiences, and level of responsibility (Company Brief at 225, citing Exh. ES-SL-1, at 11). The Company also contends that its job-scope level structure along with base pay provides a total cash compensation that is competitive to the energy/utility and general industry sectors (Company Brief at 222-223, 225, citing Exhs. ES-SL-1, at 4; AG 8-75; AG 8-78; AG 8-78; DPU 22-1; DPU 22-2; DPU 22-3; DPU 22-4; DPU 61-1; DPU 61-3; RR-DPU-23; RR-DPU-24; RR-DPU-25; RR-DPU-28; Tr. 5, at 506-507; Tr. 6 at 643, 645-646, 648-650). According to the Company, increases to base pay may take place through merit increases, promotions, progressions on job-scope levels, and market adjustment when deemed necessary (Company Brief at 225-226). With respect to the 2023 payroll increase to non-union employees, the Company claims that management made a commitment to provide the raise on April 1, 2023 (Company Brief at 226, citing RR-DPU-50). Based on these considerations, the Company asserts that it has demonstrated the non-union employee compensation is reasonable and, therefore, should be approved (Companies Brief at 225). No other party addressed this issue on brief.

c. Analysis and Findings

The Department has reviewed the test-year payroll amount and we find that it is verifiable and provides an appropriate basis upon which the Company developed the proposed rate-year non-union payroll expense (Exhs. ES-REVREQ-2, Sch. 10, at 2, 4-5 (Rev. 4); DPU 18-8, Atts. (a), (b); DPU 18-9 & Att.; DPU 40-7 & Att.). The Department's well-established standard for post-test year non-union payroll adjustments requires a company to demonstrate that: (1) the non-union salary increase is scheduled to become effective no later than six months after the date of the Department's Order; (2) if the increase has not occurred, there is an express commitment by management to grant the increase; (3) there is a historical correlation between union and non-union raises; and (4) the non-union increase is reasonable. Boston Edison Company, D.P.U. 85-266-A/85-271-A at 107 (1986); D.P.U. 96-50 (Phase I) at 42; D.P.U. 95-40, at 21; Fitchburg Gas and Electric Light Company, D.P.U. 1270/1414, at 14 (1983).

Two of the Company's proposed non-union wage increases occurred before the issuance of the Department's Order, one on April 1, 2021, and the other on April 1, 2022 (Exhs. ES-SL-1, at 12; ES-REVREQ-4, Sch. 13). Additionally, on August 2, 2022, the Company provided a management commitment letter stating that at least a three-percent payroll increase for non-union employees will take place for the scheduled wage increase in 2023 (Tr. 6, at 616-617; RR-DPU-50). Based on this information, the Department finds that non-union salary increases are scheduled to become effective no later than six months after this Order, and there is a commitment by management to grant the 2023 increase that has not yet occurred.

In addition, Eversource provided a historical correlation of non-union and union wage increases and demonstrated that it has awarded non-union and union pay increases every year since 2013 (Exh. AG 1-41, Att.). Between 2013 and 2020, union wage increases were between 2.5 percent and 3.25 percent, and non-union wage increases were 3.0 percent (Exh. AG 1-41, Att.). Based on this information, the Department finds that a sufficient correlation exists between union and non-union wage increases. See Fitchburg Gas and Electric Light Company, D.P.U. 07-71, at 76 (2008); Essex County Gas Company, D.P.U. 85-59-A at 18 (1988).

With respect to the reasonableness of the non-union wage increases, the Company annually reviews their current and projected salary levels against external energy/utility companies and the general industry to determine if they are competitive to the market median (Exh. ES-SL-1, at 13; Tr. 6, at 618). Specifically, NSTAR Electric compared its current and projected annual base salaries for non-union employees against median annual salaries for comparable positions in the Northeast by using survey data from a Towers Watson study (Exhs. ES-SL-1, at 14-17; ES-SL-5; ES-SL-6; ES-SL-7; AG 32-4; AG 32-5; AG 32-6). This comparison showed that non-union base salary and total cash compensation are two percent above market median for NSTAR Electric, and one percent above market median for ESC (Exhs. ES-SL-1, at 15-16; ES-SL-5; ES-SL-6). The result of the comparison also demonstrated that the non-union employees merit increase of three percent is consistent with the energy industry practice (Exhs. ES-SL-1, at 17-19; ES-SL-7; AG 32-10, Att. at 37). The Department finds that the Company has demonstrated that its total proposed compensation is competitive with the market median and, therefore, is reasonable.

Based on the above, the Department finds that Eversource has demonstrated: (1) non-union salary increases are scheduled to become effective no later than six months after the Department's Order; (2) there is an express management commitment to grant a three percent non-union wage increase that is scheduled to occur after the date of this Order; (3) there is a historical correlation between union and non-union payroll increases; and (4) the non-union wage increases are reasonable. Accordingly, we allow the Company's adjusted non-union payroll expense.

3. Union Wages

a. Introduction

NSTAR Electric proposes to increase the test-year adjusted union payroll expense based on: (1) Local 12004 union wage increases of three percent effective April 1, 2021, April 1, 2022, and April 1, 2023; (2) Local 369 union wage increases of three percent effective June 2, 2021, June 2, 2022, and June 2, 2023; and (3) Local 455 union wage increases of three percent effective October 1, 2021, and October 1, 2022 (Exhs. ES-SL-1, at 10; ES-REVREQ-2, Sch. 10, at 3, 4 (Rev. 4)).

b. Positions of the Parties

The Company asserts that the union employee wages are primarily negotiated through the collective-bargaining process (Company Brief at 226). Further, NSTAR Electric claims that it determines the competitiveness of the union employees' compensation by analyzing the hourly wages of its union employees against median hourly wages of other Companies' employees in the Northeast (Company Brief at 226, citing Exhs. ES-SL-1, at 8; ES-SL-2). As such, the Company asserts that it has demonstrated its union employees' wages are reasonable and that the Department should approve them (Company Brief at 226). No other party addressed this issue on brief.

c. Analysis and Findings

The Department has reviewed the test-year payroll amount and we find that it is verifiable and provides an appropriate basis upon which the Company developed the proposed rate-year union payroll expense (Exhs. ES-REVREQ-2, Sch. 10, at 2, 4-5 (Rev. 4);

DPU 18-8, Atts. (a), (b); DPU 18-9 & Att.; DPU 40-7 & Att.). The Department's standard for post-test-year union payroll adjustments requires that three conditions be met: (1) the proposed increase must take effect before the midpoint of the first twelve months after the date of the Department's Order; (2) the proposed increase must be known and measurable (i.e., based on signed contracts between the union and the company); and (3) the proposed increase must be reasonable. D.P.U. 11-01/D.P.U. 11-02, at 174; D.P.U. 96-50 (Phase I) at 43; D.P.U. 95-40, at 20; D.P.U. 92-250, at 35.

The Company's proposed union payroll adjustments appropriately include only those increases that have been granted before July 1, 2023, the midpoint of the first twelve months after the Department's Order in this proceeding (Exhs. ES-REVREQ-2 (Rev. 3), Sch. 10, at 3, 4). The union payroll increases that occurred in 2021 and 2022, as well as those scheduled to occur in 2023 are based on signed collective bargaining agreements between the Company and the respective unions (Exhs. ES-SL-1, at 9-10; ES-SL-3; AG 1-41, Att.; AG 1-42, Atts. (c), (f), (i); AG 1-43, Att.). Thus, the Department finds that the proposed union wage increases are known and measurable.

Further, with respect to the reasonableness of the union wage increases, the Company submitted a comparison of their average union wages with other employers in the Northeast (Exhs. ES-SL-1, at 9; ES-SL-2). The analysis provided demonstrates that hourly rates paid to the Company's union employees are comparable to the median hourly rates other employers in the region pay for the union employees (Exhs. ES-SL-2; AG 32-2; AG 32-3).

Thus, we find that the Company has demonstrated the reasonableness of the union wage increases. Accordingly, we allow the Company's adjusted union payroll expense.

4. Incentive Compensation

a. Introduction

NSTAR Electric's incentive compensation expense represents the portion of wages and salaries paid to non-union employees as part of the total cash compensation, and it is paid in March or April for performance in the prior year (Exh. ES-SL-1, at 21-23). During the test year, NSTAR Electric booked $16,503,810 in incentive compensation expense, net of a transmission allocation and a normalizing adjustment (Exh. ES-REVREQ-2, Sch. 11, at 1, 2 (Rev. 4)). NSTAR Electric proposes $9,682,635 for target-level incentive compensation expense in the rate year (Exhs. ES-REVREQ-1, at 70; ES-REVREQ-2, Sch. 11, at 1, 2 (Rev. 4)). Under the Company's proposal, the rate-year amount includes the test-year incentive compensation expense at the target level of $8,877,981 and a payroll escalation adjustment of $804,654 (Exhs. ES-REVREQ-1, at 69; ES-REVREQ-2, Sch. 11, at 2 (Rev. 4); Tr. 14, at 1529).

NSTAR Electric states that the proposed rate-year incentive compensation expense is lower than the test year because the Company: (1) normalized the test-year level of expense to remove out-of-period and non-recurring items; (2) reduced the revenue requirement to reflect incentive compensation at target levels; and (3) removed the cash incentive for both the chief executive officer ("CEO") and chief financial officer ("CFO"), consistent with the Department's findings in D.P.U. 17-05 and D.P.U. 19-120 (Exh. ES-REVREQ-1, at 68).[80]

b. Positions of the Parties

The Company asserts that its incentive compensation program is designed to award employees based on individual performance against the predetermined goals once the incentive pool is established after reaching its business objectives (Company Brief at 227). NSTAR Electric contends that to ensure its employees are committed to meeting customers' needs, it sets employee performance goals based on providing safe and reliable services at reasonable costs to customers (Company Brief at 227). Further, NSTAR Electric claims that its total compensation approach is designed to be competitive in the energy/utility and general industrial sectors, thus the incentive compensation remains a necessary mechanism for the Company to stay competitive in the labor market (Company Brief at 222, 227). In addition, NSTAR Electric argues that the incentive compensation included in the revenue requirement is at target level despite the payout exceeding the target level, and that the Company has removed the cash incentive compensation attributable to the Company's CEO and CFO consistent with the Department's previous findings in D.P.U. 17-05 and D.P.U. 19-120 (Company Brief at 228). Therefore, the Company asserts that it has demonstrated its

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[80] The Department recognizes that Eversource Energy's incentive compensation contains non-cash share-based incentive compensation in addition to the cash incentive compensation (Exh. DPU 61-7; RR-DPU-25). The Department directs the Company to include as part of its proposed revenue requirement in its next base distribution rate case, clearly identifiable information and contemporaneous records on share-based incentive compensation.

incentive compensation expense is reasonable and that the Department should approve it (Company Brief at 227-228). No other party addressed this issue on brief.

c. Analysis and Findings

The Department has traditionally allowed incentive compensation expenses to be included in a utility's cost of service if: (1) the expenses are reasonable in amount, and (2) the incentive plan is reasonably designed to encourage good employee performance. D.P.U. 07-71, at 82-83; D.P.U. 89-194/195, at 34. For an incentive plan to be reasonable in design, it must both encourage good employee performance and result in benefits to ratepayers. D.P.U. 93-60, at 99.

The Department first considers whether the Company's incentive compensation plan is reasonable in design. The record shows that the incentive compensation program for non-union employees is based on individual performance as collaboratively determined by the employee and the employee's supervisor for goals to achieve safety, reliability, and reasonable costs of service to NSTAR Electric's customers (Exh. ES-SL-1, at 22-24; Tr. 6, at 656-667). Each employee's incentive compensation depends on the employee's individual performance and achievement of predetermined goals each year (Exh. ES-SL-1, at 23). Specifically, every February, Eversource Energy holds a compensation committee meeting to review the performance for the previous year and set out the incentive pool available for award (Tr. 6, at 657). An employee's incentive compensation is then tied to the result of the employee's performance review within the team, i.e., an employee can earn up to 200 percent of the target level if the performance review rating is "top achiever," while another employee on the same team would not receive an incentive award if the performance review rating results in a "did not meet expectations" determination (Exh. ES-SL-1, at 23; Tr. 6, at 665-671).[81] This performance review process creates a competitive environment for employees to commit to meeting their goals of providing safe and reliable services at reasonable costs to customers (Exh. ES-SL-1, at 28; Tr. 6, at 665-667). Therefore, the Department finds NSTAR Electric's incentive compensation plan is reasonable in design.

Next, the Department considers whether the Company's incentive compensation expenses are reasonable in amount. NSTAR Electric asserts that it: (1) reduced the incentive compensation expense to the target level of $8,877,981; and (2) added a payroll escalation adjustment of $804,654 to reflect the rate year expense (Exhs. ES-REVREQ, at 69; ES-REVREQ-2, Sch. 11, at 2 (Rev. 4); Tr. 14, at 1529). According to the Company, test-year incentive compensation at target before transmission adjustment was $9,984,671 (Exh. ES-REVREQ-2, Sch. 11, at 2 (Rev. 4)).[82] However, in response to an information request, the Company provided total incentive compensation payout in 2020 of $9,450,872 (Exh. DPU 61-6, Att.).[83] Thus, although the Company maintains that it has been paying the

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[81] A performance review has five levels: top achiever, exceed expectations, meet expectations, improvement needed, and did not meet expectations (Tr. 6, at 670).

[82] The $9,984,671 amount excludes the incentive compensation amount of $555,360 for the CEO and CFO (Exhs. ES-REVREQ-2, Sch. 11, at 2 (Rev. 4); DPU 22-4).

[83] The total accrual and payout analysis provided by the Company shows that the total payout of incentive compensation in 2020 is the sum of $7,806,768 and $1,644,104 (Exh. DPU 61-6, Att.).

incentive compensation above target every year since 2010, the actual amount paid in 2020 (i.e., $9,450,872) is less than the target level amount it proposes to include in its revenue requirement (i.e., $9,984,671) (Tr. 6, at 629).

The Department has reviewed the record to determine the derivation of the Company's incentive compensation at target level. The Company states that incentive compensation is a percentage of fixed salary (Tr. 6, at 620-621, 663; Tr. 14, at 1529). NSTAR Electric's test-year incentive compensation amount at target, however, is presented in the Company's revenue requirement exhibit as a hard coded number rather than a percentage multiplying by fixed salary (Exh. ES-REVREQ-2, Sch. 11, at 2 (Rev. 4); Tr. 6, at 620-621, 663; Tr. 14, at 1529). NSTAR Electric attributes this presentation to difficulty in producing information based on the various incentive compensation payout percentages applied to different employee levels and employee groups, so the Company instead relies on the test-year booked expense (Tr. 14, at 1525). Similarly, incentive compensation allocated to NSTAR Electric from ESC based on the Company's accounting records through a cost allocation process and not is determined by multiplying the base salary by the target incentive percentage applicable to each position (Exh. AG 1-36 & Att.(a); Tr. 14, at 1511-1528).

Moreover, the Company presented allocated incentive compensation at target for some employees that exceeds 100 percent of the allocated base salary, e.g., incentive compensation at target amount of $3,028 on a base salary of $38; $5,936 on $29; and $6,860 on $1.29 (Exh. AG 1-36, Att. (a), lines 62, 255, 472). In addressing this irregularity, the Company suggested the Department examine the total amount allocated to NSTAR Electric instead of evaluating individual records, as the allocation method relies on the actual expenses (Tr. 14, at 1517).

Upon examining the evidence, the Department is unable to confirm the accuracy and reasonableness the Company's proposed test-year target level incentive compensation amount. At most, the record shows that the Company's incentive compensation expense is initially budgeted and accrued at target level each year based on percentages of fixed salary, and then adjusted upward around November or December once the mid-year management review determines that the incentive pool will be above the target level (Exhs. AG 1-36, Atts. & Supps.; DPU 22-4, Att.; Tr. 6, at 620-621; 658-659; 663; 668-669). The record, however, does not explain why the total incentive compensation payout is less than the target amount the Company proposes to include in its revenue requirement. Thus, the Department is not convinced that the test-year incentive compensation expense accurately represents the incentive compensation expense at target level. As such, the Department will not rely on the Company's proposed target level of incentive compensation to determine the allowed incentive compensation expense.

In determining the correct incentive compensation expense at target, the Department relies on the Company's derivation method of incentive compensation at target, i.e., multiplying the base salary by the target incentive percentages (Exh. AG 1-36; Tr. 6, at 663; Tr. 14, at 1529). In light of the various target incentive percentages assigned to different level of employees, the Department finds it necessary to calculate a weighted average percentage for NSTAR Electric and ESC respectively in calculating the representative target level of incentive compensation expense (Tr. 14, at 1524-1525). According to information provided by the Company, the overall weighted average percentage is the sum of each employee category's derived weighted average percentage, i.e., the ratio of number of employees to the number of total employees multiplied by the percentage of the target incentive compensation (see RR-DPU-51 & Atts. (b), (c)). This calculation produces a weighted average of 9.98 percent for NSTAR Electric and 9.47 percent for ESC, and when multiplied by the Department approved non-union employee[84] base salaries for the rate year, $20,565,307 for NSTAR Electric and $55,631,228 for ESC, produce the incentive compensation at target level of $2,052,418 for NSTAR Electric and $5,268,227 for ESC, which total $7,320,695 (Exh. ES-REVREQ-2, Sch. 10, at 3 (Rev. 4); RR-DPU-51 & Atts. (c), (b)).[85] Finally, because base salaries include a transmission portion, the Department adjusts the incentive compensation expense to exclude transmission related expense (Exh. ES-REVREQ-2, Sch. 10, at 2, 5 (Rev. 4)). The transmission-related payroll expense of $21,333,143 divided by the total rate-year payroll expense of $179,430,316 derives the factor of 11.89 percent, and when multiplied by the Department-calculated total incentive compensation at target level of $7,320,695, reflects $870,431 of transmission

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[84] The Company offers the incentive compensation plan to non-union employees only (Tr. 14, at 1512-1514; RR-DPU-51, at 1).

[85] The Company includes the incentive compensation at target percentage information for employees of NSTAR Electric and ESC and excludes ESC employees whose salaries are never allocated to NSTAR Electric as well as the incentive compensation attributable to the CEO and CFO (Tr. 14, at 1523-1524; RR-DPU-51 & Atts. (b), (c)).

related incentive compensation (Exh. ES-REVREQ-2, Sch. 10, at 2 (Rev. 4)). Therefore, the total distribution related incentive compensation expense at target level is $6,450,264 (Exh. ES-REVREQ-2, Sch. 10, at 2 (Rev. 4)). Accordingly, the Department approves a total incentive compensation expense of $6,450,264 and reduces the proposed incentive compensation by $3,232,371.[86]

5. Employee Health Care Benefits

a. Introduction

NSTAR Electric's health care benefit program includes comprehensive medical, dental, vision, and prescription drug benefits that the Company states are designed to maintain the health of employees and their eligible dependents (Exh. ES-MPS-1, at 4). In conjunction with health benefits, NSTAR Electric also offers wellness programs to help manage and improve employee health, which the Company states helps to moderate health benefit costs over time (Exh. ES-MPS-1, at 4). The Company also sponsors retirement income and health programs to contribute to employees' future financial security (Exh. ES-MPS-1, at 4). The Company states that these benefits are provided in the form of a defined contribution plan and, for a closed group of employees, a defined benefit pension plan (Exh. ES-MPS-1, at 4). Upon retirement, employees who meet certain age and service milestones are also eligible to participate in post-retirement medical plans (Exh. ES-MPS-1, at 4).

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[86] $9,682,635 - $6,450,264 = $3,232,371.

NSTAR Electric presents an adjusted test-year employee benefits expense of $15,617,670, net of capitalization (Exh. ES-REVREQ-2, Sch. 13, at 1 (Rev. 4)). The Company proposes to increase employee benefits expense by $8,119,338 (Exh. ES-REVREQ-2, Sch. 13, at 1 (Rev. 4)). The Company determines the increases through adjustments of two categories of benefits: (1) medical, dental, and vision expense; and (2) expense exclusion related to pension and PBOP (Exh. ES-REVREQ-1, at 71-72). The proposed increases of employee benefits expense are supported by a 4.8 percent and 4.7 percent annual working rate increase for 2021 and 2022 respectively (Exhs. ES-MPS-2; DPU 51-6). A "working rate" represents the per-employee expected insurance claim levels for the following year and is provided by the Company's benefits consultants and external vendor partners, Cigna and Express Scripts (Exhs. ES-DPH-1, at 58; DPU 45-34).

b. Positions of the Parties

NSTAR Electric argues that the Department should approve its employee health care benefits cost because: (1) the proposed costs are reasonable; (2) the Company has taken appropriate steps to control health care expense of the employees; and (3) the post-test-year adjustments based on the working rate are known and measurable (Company Brief at 228-237). No other party addressed this issue on brief.

c. Analysis and Findings

To be included in rates, health care expenses must be reasonable. D.P.U. 92-78, at 29-30. In addition, any post-test-year adjustments to health care expense must be known and measurable. D.T.E. 01-56, at 60; D.P.U. 96-50 (Phase I) at 46; D.P.U. 92-78, at 29;

North Attleboro Gas Company, D.P.U. 86-86, at 8 (1986). Further, companies must demonstrate that they have acted to contain their health care costs in a reasonable, effective manner. D.T.E. 01-56, at 60; D.P.U. 96-50 (Phase I) at 46; Nantucket Electric Company, D.P.U. 91-106/91-138, at 53-54 (1991).

As an initial matter, the Company derives its rate-year employee benefits costs using the number of active employees participating in the benefits program, which effectively excludes costs related to pension/PBOP from distribution rates (Exhs. ES-REVREQ-1, at 71; ES-REVREQ-2, Schs. 8, at 2; 13, at 3 (Rev. 4); DPU 26-3). This treatment is consistent with Department precedent. D.P.U. 17-05, at 324; D.P.U. 14-150, at 155.

Next, the Department finds that NSTAR Electric's employee benefits costs are reasonable, and that the Company has implemented reasonable and effective measures to contain these costs (Exhs. ES-MPS-1, at 8-11; AG 1-52). For example, the Company introduced a high deductible health plan that encourages consumerism (Exhs. ES-MPS-1, at 8; AG 1-52). The Company also offers opt-out credits to those employees who have alternative health care coverage and elect not to participate in the plans (Exh. AG 1-52). Further, NSTAR Electric consolidated medical carriers so over 98 percent of employee claims are on in-network basis that are more cost effective (Exh. ES-MPS-1, at 7). In addition, the Company negotiated a three-year agreement with a single pharmacy benefit manager coupled with step therapy programs, which provides deeper discounts for prescription drugs, lower administration fees, larger rebates, and utilization-management programs such as step therapy program that encourages the use of lower-cost generic medications (Exh. ES-MPS-1, at 9-10). NSTAR Electric also put its medical and prescription drug programs out to bid to ensure competitive pricing, resulting in all medical plans administered by Blue Cross and Blue Shield of Massachusetts and all prescription drug plans administered by Express Scripts effective January 1, 2019, which yields estimated $1.1 million in savings each year (Exhs. ES-MPS-1, at 11; AG 1-52).

Finally, the Department finds the proposed employee benefits expense based on the working rates developed by the Company's benefits consultant is known and measurable because they are derived from its total plan expense and actual claim data (Exhs. ES-MPS-1, at 11-12; ES-MPS-2; DPU 26-11; DPU 51-6, Att.). The working rates are calculated based on the Company's actual insurance claims and cost trends experienced in the two years prior to the rate year, and, therefore, we conclude that the Company's working rates are sufficiently correlated to its own experience rather than broad-based insurance entities (Exh. DPU 51-6). D.P.U. 18-150, at 241-242; Boston Gas Company and Colonial Gas Company, D.P.U. 17-170, at 103 (2018); D.P.U. 17-05, at 154; D.P.U. 15-155, at 176-177. Based on the foregoing, the Department accepts the Company's proposed health care benefit expenses.

6. Employee Service Awards

a. Introduction

During the test year, the Company recorded $20,727 in employee service awards to residual O&M expense (Exhs. DPU 61-5; AG 8-22, Att.). Under the award program, eligible employees are each presented with a paper certificate and an opportunity to choose a non-monetary service award gift in recognition of their service (Exh. AG 8-22; Tr. 6, at 676). The value of the award starts at $50 for five years of service and the maximum value is $275 for 50 years of service (Exh. AG 8-22).

b. Positions of Parties

i. Attorney General

The Attorney General argues that NSTAR Electric failed to demonstrate the employee service award provides any direct benefits or value to ratepayers (Attorney General Brief at 125, citing Exh. AG 8-22; Tr. 1, at 87; Tr. 6, at 677; Attorney General Reply Brief at 37). Further, the Attorney General contends that the Company failed to support its claim that employee service awards increase employee retention (Attorney General Brief at 125, citing Exh. ES-RR/CPP/Comp-Rebuttal-1, at 16–18). In particular, she claims that there is insufficient evidence to establish that selecting a non-cash award from a third-party vendor influences an employee's decision to remain with the Company (Attorney General Brief at 125, citing Tr. 6, at 89).[87] In addition, the Attorney General argues that the Company failed to justify the costs are reasonable even if the employee service awards theoretically benefit ratepayers or are standard in the market (Attorney General Reply Brief at 38). In this regard, the Attorney General notes that the Company does not separately

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[87] The Attorney General contends that during the evidentiary hearings, the Company's witness could not recall receiving an award separate from the paper certificate, or even if she went to the vendor website to choose the award (Attorney General Brief at 125, citing Tr. 1, at 89).

identify costs for the paper certificate and the non-cash award (Attorney General Reply Brief at 38, n. 19).

Based on these considerations, the Attorney General asserts that the Company is free to recognize its employees' service to the Company, either with paper certificates or other awards, but ratepayers should not pay for the expense (Attorney General Brief at 126; Attorney General Reply Brief at 38). Accordingly, the Attorney General recommends removing the entire amount of employee service award costs from the Company's proposed cost of service (Attorney General Brief at 126; Attorney General Reply Brief at 38).

ii. Company

The Company argues that Attorney General's claims regarding employee service awards are inaccurate and should be disregarded (Company Brief at 170-173). First, NSTAR Electric contends that the employee service awards are standard in the market and must be viewed as part of a complete compensation and benefits package designed to ensure the Company's offering is competitive (Company Brief at 171-172, citing Exh. ES-RR/CPP/Comp-Rebuttal-1, at 18; Tr. 1, at 87; Tr. 6, at 678-679). Based on surveys the Company relied upon, it claims that 70 percent of industries offer employee service awards to retain employees (Company Reply Brief at 43, citing Exh. ES-RR/CPP/Comp-Rebuttal-1, at 16).

Second, NSTAR Electric contends that, contrary to the Attorney General's assertion, the Company has demonstrated that customers benefit from the retention of skilled and highly qualified employees to provide safe and reliable service (Company Reply Brief at 44, citing

Exhs. ES-RR/CPP/Comp-Rebuttal-1, at 16-18; AG 8-22). NSTAR Electric states long-term employees acquire institutional knowledge and share it with newer employees, thereby facilitating the learning curves and ensuring effective and efficient customer assistance (Company Brief at 172). In addition, the Company maintains that it is reasonable and prudent to encourage employees who are approaching retirement age to stay in their positions as part of its standard succession planning (Company Brief at 172).

Finally, NSTAR Electric takes issue with Attorney General's claim that the Company failed to demonstrate the employee service awards have an influence on an employee's decision to remain with the Company (Company Brief at 172-173). In this regard, the Company maintains that its witness testified regarding the importance of being acknowledged for her ten years of work in providing safe and reliable service to customers (Company Brief at 172-173, citing Tr. 1, at 87, 90-91; Tr. 6, at 678-679).

c. Analysis and Findings

The Company bears the burden of demonstrating that proposed employee service award costs benefit Massachusetts ratepayers, are reasonable, and were prudently incurred. D.P.U. 11-01/D.P.U. 11-02, at 323; D.T.E. 03-40, at 140-141; Oxford Water Company, D.P.U. 1699, at 13 (1984). This standard applies whether the expenses were incurred at the parent level or at the service company level. D.T.E. 03-40, at 140-141.

The Company explained that the employee service award program is designed to recognize service, to keep employees engaged, and to retain skilled employees to operate the electric and customer service systems and pass along institutional knowledge to newer employees (Exhs. ES-RR/CPP/Comp-Rebuttal-1, at 16-18; AG 8-22; Tr. 1, at 87; Tr. 6, at 678). While the prospect of receiving an employee service award alone may not achieve these results, the recognition is part of an overall compensation and benefit package intended attract quality employees who will best serve the Company, and, by extension, customers (Exh. ES-RR/CPP/Comp-Rebuttal-1, at 18; Tr. 1, at 87; Tr. 6, at 678). The Department finds that attracting and maintaining skilled employees ultimately benefits customers through the sustained provision of safe and reliable service (Exhs. ES-RR/CPP/Comp-Rebuttal-1, at 16-18; AG 8-22; Tr. 1, at 87). We are not persuaded by the Attorney General's arguments to the contrary.

Further, the Department finds that the modest costs of the employee service award program are reasonable and prudently incurred (Exhs. DPU 26-5, Att.; DPU 61-5; Tr. 1, at 88). Cf. D.P.U. 10-55, at 454-455 & n.288 (expenditures related to shipping executives' wine collection and private school tuition found to be the type of expenses that would not have met Department standard for recovery). In this regard, given the overall costs, we find that it was unnecessary for the Company to segregate the costs of the paper certificate and the award as a prerequisite for recovery. Based on the foregoing considerations, the Department allows the Company to include $20,727 in its proposed cost of service.

B. Depreciation Expense

1. Introduction

During the test year, NSTAR Electric booked $214,446,872 in depreciation expense (Exhs. ES-REVREQ-1, at 112; ES-REVREQ-2, Sch. 25). The Company initially proposed a rate-year depreciation expense of $231,820,683, based on the application of proposed accrual rates resulting from its depreciation study to the Company's projected account balances of depreciable plant as of December 31, 2021 (Exhs. ES-REVREQ-1, at 111-114; ES-REVREQ-2, Sch. 1, at 3, Sch. 25). During the proceeding, the Company updated its proposed depreciation expense to $224,693,975 to reflect the most up-to-date balances of plant in service (Exhs. ES-REVREQ-2, Sch. 1, at 3, Sch. 25 (Rev. 4); ES-REVREQ-3, WP 25 (Rev. 4)).

NSTAR Electric's proposed depreciation accrual rates are the result of a depreciation study as of December 31, 2020, for all electric plant (Exhs. ES-JJS-1, at 2, 5; ES-JJS-2, at 6, 9; ES-JJS-3). The Company estimated the service life and net salvage[88] characteristics for depreciable plant accounts, and next used the service life and net salvage estimates to calculate composite remaining lives and annual depreciation accrual rates for each account (Exhs. ES-JJS-1, at 7-8; ES-JJS-2, at 9). To determine service lives, the Company used the retirement rate method to create life tables, which, when plotted, show an original survivor curve that is then compared to Iowa Curves[89] to determine an average service life for each

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[88] Net salvage is the resulting difference between the gross salvage of an asset when it is disposed less its associated cost of removal from service (Exh. ES-JJS-1, at 13).

[89] Iowa Curves are frequency distribution curves initially developed at the Iowa State College Engineering Experiment Station during the 1920s and 1930s; 18 curve types were initially published in 1935, and four additional survivor curves were identified in 1957 (Exhs. ES-JJS-1, at 9-10; ES-JJS-2, at 15). Boston Edison Company/Cambridge Electric Light Company/Commonwealth Electric Company/Canal Electric Company, D.T.E. 06-40, at 66-67 n. 44 (2006). These curves are widely accepted in determining average life frequencies for utility plant.

plant account (Exhs. ES-JJS-1, at 8-10; ES-JJS-2, at 15, 21). To determine net salvage values, the Company reviewed its actual historical salvage and cost of removal data through 2020 (Exh. ES-JJS-1, at 8, 13-14).

With the exception of general plant assets, the Company relied on the straight-line remaining life method and average service life procedure to determine depreciation accrual rates (Exhs. ES-JJS-1, at 15-16; ES-JJS-2, at 6). For general plant accounts 391.10, 391.20, 393.00, 394.00, 395.00, 397.00, and 389.00, the Company used the straight-line amortization method (Exhs. ES-JSS-1, at 15-16; ES-JJS-3, at 2). Additionally, NSTAR Electric proposed a five-year amortization for its unrecovered reserve (Exhs. ES-JJS-1, at 16; ES-JJS-3, at 2). As part of the depreciation study, the Company also proposed to recover the remaining book value of automated meter reading ("AMR") meters in account 370.10 by year end 2028, to align with the Company's AMI deployment plan and proposal (Exhs. ES-REVREQ-1, at 203; ES-AMI-1, at 21; ES-JJS-1, at 19). To accomplish this, NSTAR Electric proposed a terminal retirement date of 2028, resulting in a proposed accrual rate for account 370.10 of 8.62 percent (Exhs. ES-REVREQ-1, at 203; ES-AMI-1, at 21; ES-JJS-2, at 51, 256; ES-JJS-3, at 1).

2. Positions of the Parties

a. Attorney General

The Attorney General argues that the Department should reject the Company's proposed depreciation accrual rates and instead accept those proposed by her depreciation witness (Attorney General Brief at 143, citing Exh. AG-DJG-1; Attorney General Reply

Brief at 44). The Attorney General contends that NSTAR Electric underestimates service lives associated with five accounts and asserts that the Company has failed to prove that its depreciation accrual rates are not excessive (Attorney General Brief at 144, 153). The Attorney General argues her proposed depreciation rates are reasonable, based on accepted methodologies, and supported by empirical evidence (Attorney General Brief at 144-145, citing Exh. AG-DJG-1, at 7-9; Attorney Reply Brief at 43-44). Further, the Attorney General rejects the notion that her proposed service lives are only based on mathematical curve fitting, and she contends that while mathematical curve fitting was given primary consideration, visual fitting and professional judgment were also relied upon (Attorney General Reply Brief at 43-44).

Specifically, the Attorney General proposes longer average service lives for accounts 361, 362, 365, 366, and 370.20 (Attorney General Brief at 144, 146-151, 152-153). For Account 361 (Structures and Improvements), Account 362 (Station Equipment), Account 365 (Overhead Conductors and Devices), and Account 366 (Underground Conduit), the Attorney General argues that her proposed curves and average service lives provide a better mathematical fit to the Company's historical retirement data (Attorney General Brief at 146-151, citing Exh. AG-DJG-1, at 17-24; Attorney General Reply Brief at 44). For Account 370.20 (AMI Meters), the Attorney General asserts that a longer average service life of 25 years is more consistent with meter manufacturer and Company representations than NSTAR Electric's proposed average service life of 15 years (Attorney General Brief at 152-153). With respect to Account 370.10 (AMR Meters), the Attorney General proposes the same curve and average service life determined by the Company's depreciation study; however, she rejects the application of a terminal retirement date of 2028 and argues that the Company's proposal is driven by an incentive to increase cash flow (Attorney General Brief at 151-152).

Finally, the Attorney General argues the Company has not met its burden of demonstrating that its proposed depreciation expense is not excessive (Attorney General Brief at 153). Based on the above arguments, the Attorney General recommends that the Department approve her proposed depreciation accrual rates and reduce the Company's depreciation expense by approximately $17 million (Attorney General Brief at 153, citing Exh. AG-DJG-1, at 4).

b. Company

NSTAR Electric argues its depreciation study was based on historic plant data and informed by supplemental information from management and personnel, field reviews of the Company's property, estimates used by other utilities, and expert judgment (Company Brief at 238-239). NSTAR Electric asserts that the Attorney General relies exclusively on statistical analysis of the historical data and mathematical fitting, and the Company maintains that such exclusive reliance is inconsistent with authoritative depreciation texts (Company Brief at 239, 243-244, 250; Company Reply Brief at 49-50). As such, the Company argues that the Attorney General's proposed service lives and resulting depreciation accrual rates are flawed and should be rejected (Company Brief at 244, 250).

For Account 361.00 (Structures and Improvements), the Company contends its proposed 75-R3 curve is more realistic and representative of future expectations, and that the Attorney General's proposal ignores the change in asset mix from cement block structures to prefabricated steel and modular structures over time (Company Brief at 245). For Account 362.00 (Station Equipment), NSTAR Electric argues the Attorney General's proposal not only ignores more recent data and changes in substation equipment, but that her proposed curve assumes some assets will survive up to 120 years, which the Company claims is unreasonable (Company Brief at 245-256). With respect to Account 365.00 (Overhead Conductors and Devices), the Company asserts the Attorney General's proposed curve is not representative of the underlying assets, claiming her proposed curve unreasonably assumes assets with lifecycles of over 130 years (Company Brief at 246; Company Reply Brief at 50). Moreover, the Company argues the selection of the O1 type curve for Account 365.00 is problematic as it assumes the same level of retirements by age and ignores wear and tear and other influences on asset retirement and replacement (Company Brief at 246-247). Regarding Account 366.00 (Underground Conduit), the Company argues that the insufficient retirement history makes strict mathematical fitting and reliance solely on statistical results irresponsible (Company Brief at 247; Company Reply Brief at 50). Instead, NSTAR Electric contends the Department should maintain the currently approved 73-R3 curve for this account (Company Brief at 247; Company Reply Brief at 50-51).

Regarding the Company's metering accounts, NSTAR Electric avers that a retirement date of 2028 is appropriate and reasonable for Account 370.10 (AMR Meters) because all

AMR assets will be replaced with newer AMI assets by December 31, 2028 (Company Brief at 247-248). NSTAR Electric argues that if the Department rejects the proposed terminal retirement date but approves the Company's AMI plan, the Company would have approximately $55.7 million in stranded costs in 2028 (Company Brief at 248-249, citing Exh. ES-JJS-Rebuttal-1, at 20-21). The Company further contends this would lead to intergenerational inequity, as future customers would have to pay for assets that are no longer providing service (Company Brief at 248-249). For Account 370.20 (AMI Meters), NSTAR Electric argues a 15-year average service life is appropriate based on existing data and what other electric utilities use (Company Brief at 249, citing Exh. AG 25-2, Att. (a) at 7-8; Tr. 2, at 190, 196-197). The Company insists that AMI meters are technologically different than AMR meters and, therefore, they should have different service lives (Company Brief at 249, citing Exhs. AG 25-1; AG 25-2; Tr. 2, at 192-193). Further, NSTAR Electric claims that its proposed average service life for this account is consistent with its experience and industry practice and should be approved (Company Brief at 250). The Company further clarifies that an average service life of 15 years will have some meters lasting up to 28 years, which it claims is consistent with manufacturer representations (Company Brief at 250).

In conclusion, NSTAR Electric asserts that the Department should adopt the Company's proposed composite accrual depreciation rate of 2.91 percent as it is based on a combination of statistical analyses from a depreciation study, application of the depreciation expert's judgment, and current industry standards (Company Brief at 251). NSTAR Electric argues the Attorney General made no effort in her reply brief to rebut the Company's position and was unable to cite to any evidence that would suggest she relied on anything other than mathematical curve fitting (Company Reply Brief at 49-51).

3. Analysis and Findings

a. Standard of Review

Depreciation expense allows a company to recover its capital investments in a timely and equitable fashion over the service lives of the investments. Fitchburg Gas and Electric Light Company, D.T.E. 98-51, at 75 (1998); D.P.U. 96-50 (Phase I) at 104; Milford Water Company, D.P.U. 84-135, at 23 (1985); D.P.U. 1350, at 97. Depreciation studies rely not only on statistical analysis but also on the judgment and expertise of the preparer. The Department has held that when a company reaches a conclusion about a depreciation study that is at variance with that witness's engineering and statistical analysis, the Department will not accept such a conclusion absent sufficient justification on the record for such a departure. D.P.U. 92-250, at 64; The Berkshire Gas Company, D.P.U. 905, at 13-15 (1982); Massachusetts Electric Company, D.P.U. 200, at 21 (1980).

The Department recognizes that the determination of depreciation accrual rates requires both statistical analysis and the application of the preparer's judgment and expertise. Fitchburg Gas and Electric Light Company, D.T.E. 02-24/25, at 132 (2002); D.P.U. 92-250, at 64. Because depreciation studies rely by their nature on examining historic performance to assess future events, a degree of subjectivity is inevitable.[90] Nevertheless, the product of a depreciation study consists of specific accrual rates to be applied to specific account balances associated with depreciable property. A mere assertion that judgment and experience warrant a particular conclusion does not constitute evidence. Eastern Edison Company, D.P.U. 243, at 16-17 (1980); D.P.U. 200, at 20-21; Lowell Gas Company, D.P.U. 19037/19037-A at 23 (1977).

It thus follows that the reviewer of a depreciation study must be able to determine, preferably through the direct filing and at least in the form of comprehensive responses to well-prepared discovery, the reasons why the preparer of the study chose one particular life-span curve or salvage value over another. The Department will continue to look to the expert witness for interpretation of statistical analyses but will consider other expert testimony and evidence that challenges the preparer's interpretation and expects sufficient justification on the record for any variances resulting from the engineering and statistical analyses. D.P.U. 89-114/90-331/91-80 (Phase One) at 54-55. To the extent a depreciation study provides a clear and comprehensive explanation of the factors that went into the selection of accrual rates, such an approach will facilitate Department and intervenor review.

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[90] Subjectivity is especially relevant in the calculation of net salvage factors where the cost to demolish or retire facilities cannot be established with certainty until the actual event occurs. D.P.U. 92-250, at 66; D.P.U. 1720, at 44; D.P.U. 1350, at 109-110.

b. Accrual Rates

i. Account 361.00 (Structures and Improvements)

The current accrual rate for Account 361 is 1.50 percent, based on a 65-R2.5 curve for the former Western Massachusetts Electric Company ("WMECo") and a 70-R3 curve for NSTAR Electric (Exhs. ES-JJS-3; AG 7-9, Att.). The Company proposes a 75-R3 curve, which results in an accrual rate of 1.55 percent, while the Attorney General proposes an 80-R3 curve with an accrual rate of 1.44 percent (Exhs. ES-JJS-3; AG-DJG-1, at 4, 16-17; AG 7-9, Att.). While the Attorney General argues her curve provides a better mathematical fit with a sum of squared differences ("SSD")[91] of 0.0701 compared to the Company's curve exhibiting an SSD of 0.2142, it is important to note that the Company's analysis looks at two experience bands of data for this account, one from 1901 to 2020 and one from 2001 to 2020, while the Attorney General's analysis only compares her curve to the larger experience band (Exhs. ES-JJS-2, at 70-76; AG-DJG-1, at 16-17). The Company's proposal considers both bands and provides a balance between the two sets of data, whereas the Attorney General's proposal ignores more recent trends in the retirement history (Exh. ES-JJS-2, at 70). The asset's materials in Account 361 have also changed over the years, moving away from cement block structures to prefabricated and modular steel structures, which have been shown to have shorter service lives (Exhs. ES-JJS-Rebuttal-1, at 14-16; Tr. 2, at 202).

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[91] SSD is a measure of the distance between the proposed Iowa Curve and the observed life table, such that a lower SSD signifies a better mathematical fit (Exh. AG-DJG-1, at 17).

Moreover, in a review of curve-life combinations used by other utilities, no company uses an average service life for Account 361.00 greater than 75 years, and most appear to use an average service life of 65 years (Exh. DPU 8-2, Att.). Based on the foregoing analysis, the Department finds the Company's proposed 75-R3 curve is reasonable and appropriate. Thus, we approve an accrual rate of 1.55 for Account 361.00 (Structures and Improvements).

ii. Account 362.00 (Station Equipment)

The current accrual rate for Account 362.00 is 2.01 percent, based on a 47-S0 curve for WMECo and a 60-R2.5 curve for NSTAR Electric (Exhs. ES-JJS-3; AG 7-9, Att.). The Company proposes a 62-R2.5 curve, which results in an accrual rate of 2.10 percent, while the Attorney General proposes a 69-R2.5 curve with an accrual rate of 1.86 percent (Exhs. ES-JJS-3; AG-DJG-1, at 4, 18-19; AG 7-9, Att.). Comparing the two curves, the Attorney General's curve has an SSD of 0.0592, and the Company's curve has an SSD of 0.0687, both of which could be considered a reasonable fit (Exh. AG-DJG-1, at 19-20). As with Account 361.00, here the Attorney General compares her proposed curve to only one experience band of data, while the Company's proposal considers two experience bands and attempts to strikes a balance between them to capture temporal shifts in retirement trends (Exhs. ES-JJS-2, at 77-83; AG-DJG-1, at 19). From a visual fitting perspective based on the graphs provided by the Attorney General, the 69-R2.5 curve overshoots most of the data points through age 65, while the Company's curve better approximates these data points (Exh. AG-DJG-1, at 19). Furthermore, the Company's proposed 62-R2.5 curve is consistent with the average service lives utilized by comparable utilities (Exh. DPU 8-2, Att.). Based on the foregoing analysis, the Department finds the Company's proposed 62-R2.5 curve is reasonable and appropriate. Thus, we approve an accrual rate of 2.10 percent for Account 362.00 (Station Equipment).

iii. Account 365.00 (Overhead Conductors and Devices)

The current accrual rate for Account 365.00 is 3.09 percent, based on a 55-R0.5 curve for WMECo and a 48-R0.5 curve for NSTAR Electric (Exhs. ES-JJS-3; AG 7-9, Att.). The Company proposes a 60-R0.5 curve, which results in an accrual rate of 2.60 percent, while the Attorney General proposes a 66-O1 curve with an accrual rate of 2.22 percent (Exhs. ES-JJS-3; AG-DJG-1, at 4, 20-21; AG 7-9, Att.). The Attorney General's curve has an SSD of 0.1008, and the Company's curve has an SSD of 0.1768 (Exh. AG-DJG-1, at 21). Similar to Accounts 361.00 and 362.00, here the Attorney General compares her proposed curve to only one experience band of data, while the Company's proposal considers three experience bands for this account (Exhs. ES-JJS-2, at 96-105; AG-DJG-1, at 21). While the Attorney General's proposed curve provides a better mathematical fit to the larger experience band, the Company's proposal more accurately incorporates trends from more recent experience bands and considers the full set of retirement data points (Exh. ES-JJS-Rebuttal-1, at 19). Additionally, the Company's proposal is consistent with the curve-life combinations used by other utilities, as most utilize average service lives between 45 and 60 years for Account 365, and none use an O-type curve (Exh. DPU 8-2, Att.). As NSTAR Electric points out, the use of an O1 curve assumes the same level of retirements by age, unaffected by other forces of retirement such as wear and tear, which would be an unreasonable assumption (Exh. ES-JJS-Rebuttal-1, at 18-19). Based on the foregoing analysis, the Department finds the Company's proposed 60-R0.5 curve is reasonable and appropriate. Thus, we approve an accrual rate of 2.60 percent for Account 365 (Station Equipment).

iv. Account 366.00 (Underground Conduit)

The current accrual rate for Account 366.00 is 2.12 percent, based on a 65-R1.5 curve for WMECo and a 75-R3 curve for NSTAR Electric (Exhs. ES-JJS-3; AG 7-9, Att.). The Company proposes a 75-R3 curve, which results in an accrual rate of 2.10 percent, while the Attorney General proposes an 80-R3 curve with an accrual rate of 1.95 percent (Exhs. ES-JJS-3; AG-DJG-1, at 4, 22-24; AG 7-9, Att.). The Attorney General's curve has an SSD of 0.0887, and the Company's curve has an SSD of 0.1998 (Exh. AG-DJG-1, at 24). While the Attorney General's proposed curve provides a better mathematical fit based on the SSD, the retirement history and data points available for Account 366.00 are limited, with less than 15 percent of plant experiencing retirement (Exhs. ES-JJS-2, at 106-112; ES-JJS-Rebuttal-1, at 17). The Department has previously held that when an account has insufficient retirement history mathematical fitting may not be adequately relied upon to suggest a departure from a currently approved average service life and curve combination. D.P.U. 18-150, at 303. Here with a limited number of retirements, the Department does not find a compelling reason to change the 75-R3 curve that is currently used for NSTAR Electric for this account (Exhs. ES-JJS-2, at 106; AG 7-9, Att.). Further, in a review of other utilities it appears most utilize average service lives for Account 366.00 of 75 years or less, with only two out of 89 utilities using an 80-year average service life for this account

(Exh. DPU 8-2, Att.). Based on the Company's limited data and the practices of other utilities, the Department finds it is reasonable to keep the 75-R3 curve currently utilized for Account 366.00. Thus, we approve an accrual rate of 2.10 percent.

v. Account 370.10 (AMR Meters)

The current accrual rate for Account 370.10 is 5.88 percent, based on a 18-L1.5 curve for WMECo and a 23-R1.5 curve for NSTAR Electric (Exhs. ES-JJS-3; AG 7-9, Att.). While the Company's depreciation study and Attorney General both identify the 24-S0.5 curve as best matching the historical data, the Company proposes a terminal retirement date of 2028, which results in a depreciation accrual rate of 8.62 percent (Exhs. ES-JJS-2, at 142; ES-JJS-3; AG-DJG-1, at 4, 24; AG 7-9, Att.). The Attorney General states the terminal retirement date is not appropriate and proposes a depreciation accrual rate of 4.15 percent for Account 370.10 (Exh. AG-DJG-1, at 4, 24; Attorney General Brief at 151-152). The Attorney General acknowledges the Company's planned retirement of AMR meters and suggests it would not be unreasonable to apply a terminal life span to Account 370.10 if all assets are indeed retired by 2028 (Exhs. DPU-AG 2-4; Tr. 11, at 1209, 1217). The Attorney General insists, however, that the Company's proposal with respect to AMR meters is biased and simply a means to increase cash flow (Attorney General Brief at 151-152, citing Exh. AG-DJG-1, at 25-26).

The Department approved NSTAR Electric's AMI implementation plan and model tariff in D.P.U. 21-80-B/D.P.U. 21-81-B/D.P.U. 21-82-B. The Company's proposal to utilize a terminal life span retirement date of 2028 for Account 370.10 (AMR Meters) is consistent with the AMI implementation plan approved by the Department and helps ensure that customers pay for utility assets that are in-service, while limiting intergenerational inequity. Therefore, the Department approves the Company's proposed accrual rate of 8.62 percent for Account 370.10 (AMR Meters).

vi. Account 370.22 (AMI Meters)

For Account 370.22 (AMI Meters) the Company proposes a 15-S2.5 curve, which results in a depreciation accrual rate of 6.92 percent (Exhs. ES-JJS-3; AG 7-9, Att.). The Attorney General did not contest the curve-life combination in testimony, but for the first time on brief suggests that an average service life of 25 years is more appropriate for this account (Attorney General Brief at 152-153). The Attorney General contends that a 25-year average service life is more consistent with manufacturer and Company representations that AMI meters will last 20 years or more (Attorney General Brief at 152-153, citing Tr. 7, at 709, 712). While the Company and meter manufacturers acknowledge an estimated life of 20 years or more for AMI meters, NSTAR Electric accurately points out that utilizing a 15-year average service life for these assets means that some meters will last beyond 20 years, with some lasting up to 28 years (Exhs. ES-JJS-2, at 146; AG 35-1; Tr. 2, at 193, 197-199). Further, with the Company's own limited history for this account, the curve-life combinations used by other utilities can provide a relevant benchmark for industry standards. Currently, no electric utility uses an average service life of 25 years for AMI meters (Exh. DPU 8-2, Att.). Of those utilities with AMI meters, the range of average service lives is 10 to 20 years, with most using a 15-year curve (Exh. DPU 8-2, Att.). Based on the presently available information and the comparison to other electric utilities, the Department finds that a 15-S2.5 curve and corresponding accrual rate of 6.92 percent is appropriate for Account 370.22 (AMI Meters).

c. AMR and AMI Assets

As discussed in Section XV.A below, NSTAR Electric proposes a Company-specific AMI tariff consistent with the AMI implementation plan and model tariff approved in D.P.U. 21-80-B/D.P.U. 21-81-B/D.P.U. 21-82-B at 9-10, 234, 238-239, 285-286. In the instant proceeding, the Department investigated concerns regarding potential over- or under-collection of metering costs, the tracking of costs, and the potential for recovering all meter-associated costs through the Company's proposed AMI factor ("AMIF") (Exhs. DPU 9-1; DPU 33-3; DPU 43-1; DPU 46-3; RR-DPU-29; RR-DPU-33). As set forth in Section XV.C.2 below, the Department has determined the most prudent course of action is to recover all meter-related capital through the annual reconciling mechanism. As such, the depreciation expense associated with meters (Account 370.10, Account 370.21, Account 370.22, and Account 370.30) must be removed from base distribution rates. The Department reduces the Company's depreciation expense by $26,909,787 to reflect the removal of these assets from rate base (Exh. ES-REVREQ-3, Workpaper 25 (Rev. 4)).[92]

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[92] $26,909,787 represents the total depreciation expense associated with metering accounts and is the sum of $17,099,862 associated with Account 370.10 (AMR Meters), $1,047,243 associated with Account 370.21 (Non-AMR Meters – Old Technology), $7,660,959 associated with Account 370.22 (AMI Meters), and $1,101,723 associated with Account 370.30 (Metering Equipment) (Exh. ES-REVREQ-3, WP25 (Rev. 4)).

d. Land and Land Rights

As part of NSTAR Electric's proposed depreciation expense, the Company includes a total of $177,948 in depreciation expense associated with Land and Land Rights (Exh. ES-REVREQ-3, WP 25 (Rev. 4)).[93] The Department has consistently found that the purpose of depreciation is to recover the cost of a capital investment in order to replace a retired asset, and, therefore, there is no need to depreciate an asset that will not be retired. D.P.U. 93-60, at 188. See Berkshire Gas Company, D.P.U. 19580, at 16 (1978). Accordingly, the Department does not permit depreciation of land, land rights, or rights-of-way. D.T.E. 03-40, at 295; D.P.U. 93-60, at 188-189; D.P.U. 92-111, at 122; D.P.U. 19580, at 16; Western Massachusetts Electric Company, D.P.U. 18252, at 12 (1975). In the instant proceeding the Company does not provide a compelling argument to deviate from longstanding Department precedent, but simply presents a definition of "depreciation" from the Uniform System of Accounts (Exh. DPU 16-3). Therefore, the Department rejects the inclusion of $177,948 in depreciation expense associated with Land and Land Rights. Accordingly, we reduce NSTAR Electric's proposed depreciation expense by $177,948.

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[93] $177,948 represents the sum of depreciation expense associated with Account 340.00 ($140,680), Account 360.00 ($37,229), and Account 389.00 ($39) (Exh. ES-REVREQ-3, WP 25 (Rev. 4)).

e. Conclusion

The Department has reviewed NSTAR Electric's depreciation study and supporting workpapers, and we find that the Company properly supported the proposed service lives and survivor curves (Exhs. ES-JJS-1; ES-JJS-2; ES-JJS-3; DPU 8-1; DPU 8-2, Att.; DPU 8-6, Att.). Based on the analysis above, the Department finds it appropriate to reduce the Company's proposed depreciation expense by $27,087,735, for a rate-year depreciation expense of $197,606,240 (see Exh. ES-REVREQ-3, WP 25 (Rev. 4)).

C. Insurance Expense

1. Introduction

During the test year, NSTAR Electric booked $4,035,454 in insurance expense and injuries and damages expense (Exh. ES-REVREQ-2, Sch. 15 (Rev. 4)). The Company proposes to increase its test-year insurance expense by $2,171,572, resulting in a proposed insurance expense of $6,207,026 (Exh. ES-REVREQ-2, Sch. 15 (Rev. 4)). In particular, during the test year, the Company booked $357,088 in Directors and Officers liability insurance ("D&O liability insurance") coverage expense (Exh. ES-REVREQ-2, Sch. 15 (Rev. 4)). The Company proposes to increase D&O liability insurance expense by $194,489, resulting in a proposed D&O liability insurance expense of $551,578 (Exh. ES-REVREQ-2, Sch. 15 (Rev. 4)). Further, the Company did not include in its proposed insurance expense credits from its liability insurance carriers such as Nuclear Electric Insurance Limited ("NEIL") and Energy Insurance Mutual ("EIM") (Exhs. AG 8-45; AG 11-13).

2. Positions of the Parties

a. Attorney General

The Attorney General raises two issues with respect to the Company's insurance expense. First, the Attorney General argues that the Company should not be allowed to recover the full amount of D&O liability insurance coverage expense (Attorney General Brief at 123-125). Second, the Attorney General argues that the Company failed to reflect future NEIL and EIM credits in its rate year (Attorney General Brief at 126-127, citing Exhs. AG-LA-1, at 28-30; AG 8-45; AG 11-13).

Regarding the D&O liability insurance coverage expense, the Attorney General claims that the cost of these policies should not be fully borne by the ratepayers because the majority of the benefits resulting from D&O liability insurance coverage, which protects the Company's officers and directors from lawsuits arising from their own decisions, accrue to the Company and its shareholders (Attorney General Brief at 123). The Attorney General contends that the burden rests with the Company to demonstrate that ratepayers will receive measurable benefits in exchange for the costs of its D&O liability insurance coverage, and that the Company failed to make such a showing (Attorney General Brief at 123, citing Town of Hingham v. Department of Telecommunications and Energy, 433 Mass. 198, 213-214 (2001), citing Metropolitan District Commission, 352 Mass. 18, 24; Wannacomet Water Company v. Department of Public Utilities, 346 Mass. 453, 463 (1963); D.T.E. 99-118, at 7 n.5).

The Attorney General, however, recognizes that the D&O liability insurance policies may assist the Company in attracting higher-quality personnel (Attorney General Brief at 124, citing Exh. ES-RR/CPP/Comp-Rebuttal-1, at 9-10; Western Massachusetts Electric Company, D.P.U. 86-280-A, at 92 (1987)). Thus, the Attorney General argues that, despite the Company's failure to meet its burden of proof, shareholders and ratepayers should share the cost of these insurance expenses (Attorney General Brief at 124, citing Exh. ES-RR/CPP/Comp-Rebuttal-1, at 9-10; D.P.U. 86-280-A, at 92). Specifically, the Attorney General recommends that shareholders bear 75 percent, while ratepayers bear 25 percent, of the allocated D&O liability insurance coverage costs (Attorney General Brief at 124). The Attorney General notes that her recommendation is consistent with rulings by the Connecticut Public Utilities Regulatory Authority ("CT PURA") and other public utilities commissions (Attorney General Brief at 124, citing United Illuminating Company, CT PURA Docket No. 16-06-04, at 36 (2016); Ni Florida, LLC, FL PSC Docket No. 160030-WS, Order No. PSC-16-0525-PAA-WS, at 8 (2016); Connecticut Natural Gas Corporation, CT PURA Docket No.13-06-08, at 27 (2014); Entergy Arkansas, Inc., Arkansas PSC Docket No. 06-101-U, Order No. 10, at 70, (2007); Centerpoint Energy Resources Corp., Arkansas PSC Docket No. 04-121-U, Order No. 16, at 40 (2005); Southwest Gas Corporation, CPUC Application 02-02-012, Decision 04-03-034, at 34-35 (2004)). Therefore, the Attorney General recommends reducing the Company's proposed cost of service by $335,135 to represent a 75/25 sharing of these costs between shareholders and ratepayers, respectively (Attorney General Brief at 124-125, citing Exh. AG-LA-2, Sch. 4).[94]

Regarding the NEIL and EIM insurance credits, the Attorney General argues that the Company failed to reflect future credits in its rate year (Attorney General Brief at 126-127, citing Exhs. AG-LA-1, at 28-30; AG 8-45; AG 11-13). The Attorney General posits that while the NEIL and EIM credits are not guaranteed to occur, it is very likely that they will occur in the future based on the Company's insurance historical records (Company Brief at 126-127, citing Exhs. AG-LA-Surrebuttal-1, at 8; ES-RR/CPP/Comp-Rebuttal, at 26). The Attorney General asserts that the historical record shows that the Company has received NEIL and EIM insurance credits from 2017 through 2021, and there is no reason to assume that these credits will not occur in the future (Attorney General Brief at 127, citing Exh. ES-RR/CPP/Comp-Rebuttal-1, at 26). Further, she argues that the Company will reap a financial windfall if the Company is allowed to keep these credits to the detriment of ratepayers (Attorney General Brief at 126-127, citing Exh. AG-LA-Surrebuttal-1, at 8). Therefore, the Attorney General argues that it is appropriate and important to include these credits as part of the Company's pro forma rate-year adjustment (Attorney General Brief at 127). Because the amounts of these credits fluctuate over time, the Attorney General recommends that the Company include a five-year average of credits in the pro forma

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[94] The Attorney General's proposed adjustment appears to be based on the Company's initial proposed test-year pro forma amount of D&O liability insurance expense, and the not the final amount proposed for recovery (Exhs. ES-REVREQ-2, Sch. 15; ES-REVREQ-2, Sch. 15 (Rev. 4)).

test-year amount (Attorney General Brief at 126-128, citing Exhs. AG-LA-2, Schs. 8, 9; AG 1-61, Att. I (Supp. 1)). Thus, the Attorney General asserts that the Department should reduce NSTAR Electric's proposed insurance expense by $50,575 and $449,835 to reflect NEIL and EIM insurance credits, respectively (Attorney General Brief at 126-128, citing Exhs. AG-LA-2, Schs. 8, 9; AG 1-61, Att. I (Supp. 1)).

b. Company

NSTAR Electric asserts that the Attorney General's arguments and conclusions regarding the D&O liability insurance expense are flawed, against recent Department precedent, and should be disregarded (Company Brief at 179-180, citing D.P.U. 20-120, at 302-304). The Company contends that it has taken steps to control costs associated with this insurance coverage, which is a direct benefit to customers (Company Brief at 180-181, citing Exhs. ES-REVREQ-1, at 87-90; ES-RR/CPP/Comp-Rebuttal-1, at 8; DPU 15-8; DPU 15-10; DPU 55-3; AG 1-61 & Supp.; AG 1-63 & Supp.; AG 8-18). Further, the Company claims that the primary purpose of the D&O liability insurance coverage is not to cover bad faith actions of its directors and officers (Company Brief at 181, citing Exhs. ES-RR/CPP/Comp-Rebuttal-1, at 9; DPU 55-3). Instead, NSTAR Electric asserts that D&O liability insurance coverage protects its management should they be personally exposed to liability claims for the business decisions and actions they make while operating the Company, thus enabling its leadership to make business decisions confidently without the fear of personal financial loss (Company Brief at 181, citing Exh. ES-RR/CPP/Comp-Rebuttal-1, at 9).

NSTAR Electric also contends that D&O liability insurance coverage benefits customers by ensuring that the Company is able to attract and retain skilled, experienced officers and trustees with long-term ties to the electric distribution industry who use their specialized areas of knowledge and expertise to provide safe and reliable service to customers (Company Brief at 181-182, citing Exh. ES-RR/CPP/Comp-Rebuttal-1, at 9-10). Finally, NSTAR Electric argues that the Attorney General's recommended cost sharing of D&O liability insurance expenses is arbitrary and unsupported by any analysis and, therefore, should be rejected (Company Brief at 182 & n.59, citing Exh. ES-RR/CPP/Comp-Rebuttal-1, at 8 n.2).

Regarding the NEIL and EIM insurance credits, NSTAR Electric argues that the Department should reject the Attorney General's recommendation because there is no guarantee that these credit distributions, prior years' distribution notwithstanding, will occur in the future (Company Brief at 182-183). In support of its position, the Company contends that it is unknown whether any NEIL and EIM insurance credit distributions will occur in the future and, therefore, the Attorney General's proposal is unmeasurable (Company Brief at 183). Further, the Company claims that it is inappropriate to utilize the five-year average of credit distributions because the annual distributions tend to fluctuate significantly (Company Brief at 183).

NSTAR Electric also argues that, adhering to the Department's regulatory principles, it would not propose to include speculative costs in the revenue requirement that do not pass the Department's known and measurable standard (Company Brief at 183). Thus, the

Company argues that any reduction to the Company's insurance expense should not be based on speculation, and therefore, the Department should reject the Attorney General's recommendation (Company Brief at 182-183).

3. Analysis and Findings

Rates are designed to allow for recovery of a representative level of a company's revenues and expense based on a historic test year adjusted for known and measurable changes. D.P.U. 10-55, at 274; Bay State Gas Company, D.P.U. 09-30, at 218 (2009); D.T.E. 02-24/25, at 161; D.P.U. 92-250, at 106. The Department will include the most current cost of liability and property insurance, based on a signed agreement, as a reasonable cost of service. D.P.U. 10-55, at 276; D.P.U. 09-30, at 218; D.T.E. 02-24/25, at 161; D.P.U. 86-86, at 8-10; Colonial Gas Company, D.P.U. 84-94, at 44 (1984). The Department requires companies to provide evidence that they undertook reasonable measures to control property and liability insurance expenses. New England Gas Company, D.P.U. 08-35, at 119-120 (2009); D.T.E. 05-27, at 133-134; D.T.E. 03-40, at 184-185.

As noted above, the Attorney General contends that the Company should not be allowed to fully recover D&O liability insurance expense, and instead should share these costs with ratepayers (Attorney General Brief at 123-125). We disagree. In evaluating the Company's D&O liability insurance coverage, the Department considers whether the primary purpose of the policy is to cover bad faith actions and whether ratepayers receive measurable benefits. D.P.U. 20-120, at 302; D.P.U. 87-260, at 72-73; Commonwealth Gas Company, D.P.U. 87-122, at 51, 53-54 (1987); D.P.U. 87-59, at 41-42. In determining ratepayer benefits, the Department considers whether ratepayers would otherwise be required to pay for damages and legal fees arising out of such suits brought against the Company's directors and officers in the event the Company did not have such insurance. D.P.U. 20-120, at 302-303; D.P.U. 87-260, at 73. The record in this case demonstrates that the purpose of the Company's D&O liability insurance policy is to protect its directors and officers should they be personally exposed to liability claims for the business decisions and actions they make while employed by the Company or serving as a trustee, and to protect the personal assets of trustees and officers in a related lawsuit (Exh. DPU 55-3).

The record does not support a finding that the primary purpose of the D&O liability insurance policy is to protect the utility against bad faith actions of its directors and officers. In fact, such actions are expressly excluded by the policy (Exhs. ES-RR/CPP/Comp-Rebuttal-1, at 8-9; DPU 55-3 & Att.).[95] Thus, the Department finds that coverage by the D&O liability insurance policy primarily involves actions where the costs could be included in the Company's cost of service absent D&O liability insurance and, as such, the policy offers ratepayer benefits. D.P.U. 20-120, at 303. As such, we find that the costs associated with the Company's D&O liability insurance coverage are properly included in rates. D.P.U. 20-120, at 303-304; D.P.U. 87-260, at 73; D.P.U. 87-122,

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[95] For instance, the policy excludes claims in the event that a director or officer: (1) used their position to gain personal profit, financial advantage, or remuneration to which they were not entitled; or (2) committed a deliberately fraudulent or criminal act or omission or any intentional violation of any law, statute, or regulation (Exh. DPU 55-3, Att.).

at 53-54; D.P.U. 87-59, at 41-42. Based on these findings, we need not address the merits of the Attorney General's recommended cost sharing approach.

Regarding the NEIL and EIM insurance credits, the record shows that NEIL made policy surplus distributions or insurance credits during the test year and in each of the prior five years (Exhs. AG 8-45; AG 1-61, Att. (e) (Supp. 1)). Likewise, EIM made similar policy surplus distributions during the test year and in each of the prior five years (Exhs. AG 11-13; AG 1-61, Att. (e) (Supp. 1)). Given this consistent history of credit receipts from NEIL and EIM, we are not persuaded by the Company's argument that there is no guarantee that these surplus distributions will occur in the future, and, therefore, are not known and measurable. D.P.U. 17-05, at 246-246. Further, the Department has found that EIM's policy surplus distributions are analogous to those made by NEIL. See D.P.U. 87-260, at 26-36. As a mutual non-profit carrier, NEIL makes policyholder distributions to recognize a return of a portion of the policy's surplus. The Department has required participants to credit policyholder distributions and other adjustments to customers in a manner approved by the Department. New England Power Company/Montaup Electric Company, D.P.U. 1251, at 10 (1983); Western Massachusetts Electric Company, D.P.U. 990-A at 10 (1982); D.P.U. 990, at 4; Western Massachusetts Electric Company, D.P.U. 147-B at 2-3 (1981); Boston Edison Company, D.P.U. 376-A at 2 (1981); D.P.U. 376, at 15-16. The Department has historically treated such credits as an offset against the current NEIL premium for ratemaking purposes because "policyholder distribution is a known and measurable change that should be included as an offset to the

Company's current NEIL premiums." D.P.U. 87-260, at 38-39.[96] Consistent with the treatment of NEIL surplus distributions in prior cases, the Department finds that, for the reasons explain above, it is also appropriate to adjust the Company's test year pro-forma cost of service to recognize the refund of the insurance proceeds from EIM, as well. D.P.U. 17-05, at 246.

Between 2017 and 2021, NEIL credits per year have ranged from a low of $4,472 in 2017 to a high of $105,590 in 2020, and EIM credits per year have ranged from a low of $217,583 in 2017 to a high of $767,872 in 2019 (Exh. AG-LA-2, Schs. 9 & 10). Thus, the test-year level of NEIL and EIM credits are not necessarily representative. Therefore, the Department finds that it is appropriate to normalize test-year NEIL and EIM credits by applying a five-year average to determine a representative level to be included in rates. <u>See</u> D.P.U. 09-39, at 149. Normalization is not intended to ensure dollar-for-dollar recovery of a particular expense or credit; rather it is intended to include in the cost of service as a representative annual level. D.P.U. 10-55, at 339; D.T.E. 05-27, at 163; D.T.E. 03-40, at 163-164; D.T.E. 02-24/25, at 191; D.P.U. 96-50 (Phase I) at 77.

Based on the above considerations, the Department will adjust the Company's cost of service. In this regard, the Department accepts the Attorney General's calculation of the five-year credit averages, based on information provided by the Company (Exhs. AG-LA-2,

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[96] This ratemaking treatment is similar in concept to patronage refunds associated with CoBank, a lending institution that focuses on water systems, where the refunds serve to reduce the effective cost of the loan. <u>Whitinsville Water Company</u>, D.P.U. 08-33, at 14 (2008).

Schs. 8 and 9; AG 1-61, Att. (e) (Supp. 1)). Accordingly, the Department reduces NSTAR Electric's proposed cost of service by \$500,410 (\$50,575 + \$449,835) (Exhs. AG-LA-2, Schs. 8 and 9; AG 1-61, Att. (e) (Supp. 1)).

The Department has reviewed NSTAR Electric's remaining insurance policies and supporting documentation. We find that the test-year insurance costs were reasonable, and the insurance expense premiums and proposed adjustments are based on actual policy rates and are thus known and measurable (Exhs. ES-REVREQ-1, at 88-92; ES-RR/CPP/Comp-Rebuttal-1, at 34-36; AG-DJE-1, at 9-12; AG-DJE-Surrebuttal-1, at 5-7; ES-REVREQ-2, Sch. 15 (Rev. 4); DPU 15-7, DPU 15-10; DPU 15-11; DPU 15-13, Supp. & Atts.; DPU 69-11 & Atts.; AG 1-61 & Atts. & Supps.; AG 4-19 & Att.; Tr. 1, at 145-146; RR-DPU-4 & Atts.; RR-AG-3). Further, the Department finds that NSTAR Electric has taken reasonable measures to control the costs of its insurance expense (Exh. DPU 15-8). Thus, with the exception of the adjustments set forth above, the Department accepts the Company's proposed insurance expense.

D. Board of Director Expenses

1. Introduction

Eversource Energy is governed by an eleven-member board of trustees, of whom ten are independent and one is a member of management (Exh. AG 1-2, Att. (5)(e) at 11). Each independent trustee receives an annual base retainer of \$115,000, with additional amounts for serving as lead trustee and committee chairs, along with \$160,000 in restricted stock units ("RSUs") (Exh. AG 1-2, Att. (5)(e) at 38). NSTAR Electric itself has a board of directors consisting of five Company officers who receive no additional compensation for their director responsibilities (Exhs. DPU 52-2; AG 1-2, Att. (6)(e) at 12 (Supp. 1)).[97] During the test year, the Company booked $930,151 in board fees and meeting costs to its distribution operations (Exhs. DPU 52-2; AG 8-4, Att.; AG 21-7, Att.).[98] These costs include the Company's allocated portion of cash retainers and RSUs paid to the independent members of Eversource Energy's board of trustees[99] (Exhs. ES-RR/CPP/Comp-Rebuttal-1, at 5; DPU 52-2; AG 1-2, Att. (5)(e) at 38; AG 21-7, Att.; Tr. 6, at 642).

2. Positions of the Parties

a. Attorney General

The Attorney General asserts that the Department has made it clear that for costs to be recovered from ratepayers, a company must demonstrate that there is a link between the costs and ratepayer benefits (Attorney General Brief at 121, citing D.P.U. 20-120, at 224; D.P.U. 93-60, at 201; D.P.U. 92-111, at 127). The Attorney General contends that while

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[97] For purposes of this Order, the Department uses "board of trustees" when referring to Eversource Energy's governing body, "board of directors" when referring to the Company's own governing board, and "board" when referring to both the board of trustees and board of directors.

[98] While the Company did not propose an explicit adjustment to its test-year board expenses, the Company's proposed inflation allowance incorporates an increase to these expenses of $138,795, representing inflation of 14.909 percent from the midpoint of the test year to the midpoint of the rate year (see Exhs. ES-REVREQ-3 WP 24 (Rev. 4); AG 8-4, Att.).

[99] The Company is only seeking rate recovery of trustee retainers and RSUs, and no other expenses trustees may incur in their duties such as travel expenses (Exh. AG 21-7, Att.; Tr. 6, at 642).

the existence of the Company's board of trustees logically produces some tangential benefits to ratepayers, the Company's shareholders are the major beneficiaries associated with the proposed board fees and associated meeting costs (Attorney General Brief at 121-122, citing Exhs. AG-LA-1, at 11-12; ES-RR/CPP/Comp-Rebuttal-1, at 6).

The Attorney General argues that to better reflect the balance of benefits arising from a board of trustees between the Company and ratepayers, the Department should disallow 75 percent of board fees and meeting costs, resulting in what she calculates as a reduction of $751,267 (i.e., the inflation-adjusted pro forma expense of $1,001,689 x 75 percent) (Attorney General Brief at 122, citing Exhs. AG-LA-1, at 12; AG-LA-2, Sch. 2, Att.).[100] The Attorney General asserts that this ratemaking treatment is consistent with rulings from other jurisdictions, such as in Connecticut, where the CT PURA has allocated 75 percent of board of director costs to shareholders (Attorney General Brief at 122, citing Connecticut Water Company, CT PURA Docket No. 20-12-30, at 12-14 (2021); United Illuminating Company, CT PURA Docket No. 13-01-19, at 73 (2013)).

b. Company

NSTAR Electric argues that to recover board fees in cost of service, the Department requires a company to demonstrate a link between those fees and customer benefits (Company Brief at 184, citing D.P.U. 20-120, at 329). The Company challenges what it considers to be the Attorney General's attempt to create a new standard for recovery of board

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[100] The Attorney General's calculations are based on the Company's initially-proposed inflation factor of 7.691 percent (Exhs. AG-LA-2; AG 8-4, Att.).

fees based on a requirement that ratepayers must be the majority or sole beneficiaries of these expenditures (Company Brief at 184).

The Company argues that the Attorney General has mischaracterized the customer benefits associated with board fees (Company Brief at 184). While NSTAR Electric acknowledges that Eversource Energy's board of trustees is tasked with representing shareholder interests, the Company contends that the Attorney General fails to recognize that actions taken to meet the board's obligations to shareholders also directly, and not tangentially, benefit customers (Company Brief at 184, citing Exh. ES-RR/CPP/Comp-Rebuttal-1, at 6). NSTAR Electric points to the organization of the board of trustees and various standing committees, as well as Eversource Energy's shift in accordance with nationwide trends from a per-meeting fee structure to providing a cash retainer and stock award in the form of RSUs (Company Brief at 185, citing Exhs. AG 1-2, Att. (5)(e) at 22-28; AG 21-7; Tr. 3, at 284-287; Tr. 6, at 637).[101] The Company contends that the board's organization and compensation structures ensure that board members have a stake in Eversource Energy (and by extension the Company), take a hands-on approach in executing their duties as board members, and are actively involved in managing the direction of the Company (Company Brief at 185-186, citing Tr. 7, at 639-640). NSTAR Electric also maintains that in protecting shareholder interests, the board of trustees ensures that the

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[101] The Company relies on a national benchmark in setting trustee compensation, including a review of peer utilities, and contends that it targets the median level (Company Brief at 186, citing Tr. 7, at 637-640).

Company's assets, including those used to provide safe and reliable service to customers, are in good working order, as well as demonstrates to the financial markets and prospective shareholders that the Company is a solid and attractive financial investment (Company Brief at 184-185, citing Exh. ES-RR/CCP/Comp-Rebuttal-1, at 6). The Company argues that by attracting new shareholders, the board of trustees ensures that the Company benefits from a revenue stream that is used to fund capital projects that provide safe and reliable service to customers (Company Brief at 185, citing Exh. ES-RR/CPP/Comp-Rebuttal-1, at 6).

NSTAR Electric goes on to argue that even if there is no connection between board fees and benefits to customers, the Attorney General has failed to provide any analysis to support her recommended 75 percent disallowance beyond a brief reference to a similar conclusion by the CT PURA (Company Brief at 186, citing Exh. AG-LA-1, at 13-14 (Rev.)). The Company contends that a review of the PURA orders relied upon by the Attorney General demonstrates that the CT PURA's decisions were not based on any analysis, and that the Attorney General's recommendation is based on an arbitrary determination of costs and benefits (Company Brief at 186).

3. Analysis and Findings

The Department recognizes that a company incurs certain costs related to the operations of its board of directors, such as director fees and other expenses. Aquarion Company/Aquarion Water Company of Massachusetts/New England Service Company/Mountain Water Systems/Colonial Water Company, D.P.U. 21-54, at 26 (2021); Aquarion Water Company of Massachusetts, D.P.U. 08-27, at 88-92 (2009); D.T.E. 03-40, at 206-207; D.P.U. 92-111, at 147-148. While the Attorney General does not oppose the recovery of expenses related to the board on a per se basis, she proposes a sharing of these costs between the Company and its ratepayers on the basis of her benefits evaluation (Exh. AG-LA-1, at 13-14 (Rev.)).

A board of trustees or directors does not exist merely to satisfy legal governance requirements. Rather, it contributes to and shapes a company's culture, strategic focus, and financial performance, all of which are essential elements for any organization. While it is certainly true that neither Eversource Energy's board of trustees nor the Company's own board of directors are elected by ratepayers, the fiduciary duties of a regulated utility's governing body extend well beyond interests of shareholders. Specifically, a regulated utility is obligated to act in the best interest of ratepayers as part of that company's public service obligation to provide safe, reliable, and least-cost service. See D.P.U. 10-70, at 234 n.125; D.P.U. 07-50, at 5; D.P.U. 94-158, at 3; Boston Edison Company, D.P.U. 94-49, at 115-116 (1995); Boston Edison Company, D.P.U. 86-71, at 15-16 (1986). Consequently, decisions made by a utility's management and governing body cannot, and must not, prioritize shareholder interests over those of ratepayers. See Mergers and Acquisitions, D.P.U. 93-167-A at 22-23 (1994); Bay State Gas Company, D.P.U. 90-40, at 9-11 (1990).[102] The Department also notes that, unlike business organizations whose directors are chosen on

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[102] Utilities that fail to recognize this fundamental principle do so at their own peril. D.P.U. 85-266-A/85-271-A at 6-15.

the basis of the prestige they may provide to the enterprise,[103] Eversource Energy's board of trustees actively participates in the operations of Eversource Energy and its subsidiaries both collectively and through their active participation in various committees (Exh. AG 1-2, Att. (5)(e) at 22-28; Tr. 3, at 284-287; Tr. 6, at 637-640). Given the distinct public service obligations of a regulated utility's board of trustees or directors and the active participation of Eversource Energy's board of trustees in its operations, the record does not support a finding that the primary purpose of the board of trustees is to serve the interests of Eversource Energy's shareholders.[104] Based on these findings, we need not address the merits of the Attorney General's proposed allocation method.

Based on the foregoing analysis, the Department concludes that Eversource Energy's board of trustee activities benefit ratepayers.[105] Accordingly, the Department accepts

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[103] As a case in point, the now-defunct blood testing equipment manufacturer Theranos had a board of directors consisting of former cabinet members, congressmen, and military officials. While these directors may have sterling reputations in their respective fields, they do not appear to have been sufficiently involved in Theranos' medical technology business to engage in effective oversight.

[104] To assume otherwise sets the entire concept of utility regulation back to the days of Framingham Gas, Fuel, and Power Company, a "notoriously slovenly and corrupt affair" where one of the last corporate acts of previous management, at the onset of an investigation by the Board of Gas and Electric Light Commissioners, was to "lose" their entire body of records. Manufactured Gas Plant Remediation: A Case Study, Allen W. Hatheway and Thomas B. Speight, CRC Press (2018) at 381.

[105] The Department reminds Eversource Energy and the board of trustees of the importance of keeping customer benefits in mind during this upcoming winter season of anticipated high utility prices. While we recognize that Eversource Energy has little control over commodity prices, it does control other aspects of utility operations, such as customer shut-offs and arrearage management. We expect Eversource Energy

NSTAR Electric's proposal to include the Company's share of expenses associated with Eversource Energy's board of trustees in the Company's cost of service.

E. Dues and Memberships

1. Introduction

NSTAR Electric maintains memberships in various industry and non-industry trade associations and organizations (Exhs. ES-REVREQ-1, at 70; ES-REVREQ-3, WP 12 (Rev. 4); AG 8-19, Att.). The Company refers to "industry" memberships as specific only to the utility industry and "non-industry" memberships as everything else (i.e., not specific to the utility industry) (Exh. DPU 53-1). NSTAR Electric proposes $442,380 for industry dues expense and $359,967 in non-industry dues expense, for a total test year pro forma amount of $802,347 in dues and memberships expense (Exhs. ES-REVREQ-2, Sch. 12 (Rev. 4); ES-REVREQ-3, WP 12 (Rev. 4); DPU 53-2, Att.).

2. Positions of the Parties

a. Attorney General

The Attorney General argues that the Department should not allow the recovery of certain non-industry dues and membership expenses because the Company has not demonstrated a clear link between those costs and ratepayer benefits (Attorney General Brief at 128-130; Attorney General Reply Brief at 39). The Attorney General claims that for the majority of the non-industry organizations for which the Company seeks to recover dues, it

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and the board, to take those necessary actions to protect ratepayers during the challenging winter season.

has offered only generalized ratepayer benefits without support for its assertions, and therefore, these costs should not be recovered from ratepayers (Attorney General Brief at 128-129, citing Exhs. AG-LA-1, at 19; DPU 15-1).

The Attorney General also argues that the Company, on brief, provides additional explanations and cites to information that it had not provided as record evidence in this proceeding, including describing organizations such as the International Energy Credit Association and ORC HSE Strategies, LLC, and citing to five organizations' websites (Attorney General Reply Brief at 39, citing Company Brief at 164-165). According to the Attorney General, NSTAR Electric bears the burden of demonstrating the link between the dues for which it seeks cost recovery and ratepayer benefits, and the Company's citing to this additional information as information that the Attorney General should have considered attempts to shift that burden (Attorney General Reply Brief at 39). The Attorney General also maintains that Company's attempt to shift the burden proves that the Company failed to meet its burden for cost recovery (Attorney General Reply Brief at 39).

Further, the Attorney General disputes the Company's inclusion of two entries for the same organization, i.e., Associated Industries of Massachusetts ("AIM") (Attorney General Brief at 129 & n.98). The Attorney General maintains that the double entry is a result of the Company paying dues for two calendar years in the test year, which is not a representative amount for this expense in a given year; therefore, one of the entries should be excluded from the revenue requirement (Attorney General Brief at 129 & n.98, citing Exh. DPU 53-2; RR-AG-11). Based on the above arguments, the Attorney General recommends a disallowance of $347,854 in non-industry dues expense as well as one of the AIM entries (Attorney General Brief at 129; Attorney General Reply Brief at 39).[106]

b. Company

NSTAR Electric argues that the Department should reject the Attorney General's recommendation as it ignores record evidence that demonstrates the link between the various organizations and customer benefits (Company Brief at 163). Further, NSTAR Electric rejects the distinction between "industry" and "non-industry" dues and memberships, and the Company asserts that it belongs to these organizations because membership provides access to industry experts and professionals, insight, data, research, and information used to address emergent issues facing the industry and to identify and incorporate relevant information and best practices into the provision of safe and reliable service to its customers (Company Brief at 163-165, citing Exhs. ES-RR/CPP/Comp-Rebuttal-1, at 13-16; DPU 38-1; DPU 53-2; Tr. 5, at 494; Company Reply Brief at 45).

For example, NSTAR Electric contends that membership in organizations such as the Chambers of Commerce allows the Company to interact with its customers, learn about local issues impacting customers, and shape the way the Company services these customers; therefore, there is a direct link between membership and customer benefits (Company Brief

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[106] The Attorney General notes that its recommended disallowance excludes adjusted test-year amounts for four organizations (American Benefits Council, the Drug and Alcohol Testing Industry Association, the Electric Utility Industry Sustainable Supply Chain Alliance, and the Northeast Human Resources Association) that the Company discussed in the benefits section of its surrebuttal testimony (Attorney General Brief at 129-130, citing Exhs. ES-RR/CPP/Comp-Rebuttal-1, at 13-16; DPU 53-2, Att.).

at 164, citing Tr. 5, at 494). Moreover, NSTAR Electric maintains that memberships in other non-industry categories such as ORC HSE Strategies, LLC, provides the Company access to industry experts and helps it develop processes and procedures to identify and reduce or remove potential workplace hazards and to train employees for accident prevention and response (Company Brief at 165). The Company contends that workplace safety is a key component of the provision of safe and reliable service, which benefits customers (Company Brief at 165).

In response to the Attorney General's assertion that the Company provided new evidence to demonstrate that certain dues are appropriate for cost recovery, NSTAR Electric contends that each of the organizations referenced in its initial brief were included in the Company's responses to information requests in this proceeding (Company Reply Brief at 44, citing Exhs. DPU 38-1; DPU 53-2). NSTAR Electric asserts that by including these organizations in these responses, the Company determined that they met the Department's standard for recovery (i.e., there is a link between the dues and customer benefits) (Company Reply Brief at 44-45, citing D.P.U. 20-120, at 329; Bay State Gas Company, D.P.U. 92-111, at 127 (1992); Milford Water Company, D.P.U. 92-101, at 54 (1992); The Berkshire Gas Company, D.P.U. 90-121, at 151 (1990)). Further, according to the Company, the missions of these organizations and their connection to providing customers with safe and reliable service are objective facts that are capable of definitive verification and are readily available to the Department and the Attorney General (Company Reply Brief at 45 & n.7).

For all of the above reasons, NSTAR Electric claims that it met the Department's standard for inclusion of these costs, and the Department should reject the Attorney General's recommendations (Company Brief at 166, citing Exhs. ESRR/CPP/Comp-Rebuttal-1, at 13-16; AG 22-2; AG 38-1; DPU 15-1, DPU 53-1; Company Reply Brief at 45). Finally, the Company agrees with the Attorney General that the Department should remove one of the double entries associated with AIM, a reduction of $15,312 from its proposed cost of service (Company Brief at 165-166).

3. Analysis and Findings

The Department requires that the Company demonstrate a link between non-industry dues and memberships and ratepayer benefits for the costs to be recoverable in rates. See, e.g., D.P.U. 92-111, at 127; D.P.U. 92-101, at 54; D.P.U. 90-121, at 151. In support of its position that the costs should be recoverable, the Company generally states that all of the organizations offer insight, expertise, industry data, publications, and best practices that the Company uses to provide safe and reliable service (Company Brief at 163-165, citing Exh. ES-RR/CPP/Comp-Rebuttal-1, at 13-16; DPU 38-1; DPU 53-2; Tr. 5, at 494; Company Reply Brief at 45). The Department asked the Company to outline specific, direct customer benefits related to each of its non-industry dues and memberships, and the Company's response was in the form of brief, general explanations, noting vague benefits such as input to inform the Company's efforts to provide service to customers and the opportunity to meet with business customers to exchange ideas to facilitate the Company's service to customers (Exhs. DPU 15-1; DPU 53-1).[107] While the Department recognizes that some of these memberships may help provide insight to NSTAR Electric on issues relevant to its business, the Company has not demonstrated that there is a clear link between the Company's memberships in the majority of these non-industry organizations and meaningful benefits to customers, or that these memberships are necessary to the provision of electric distribution service to customers.

Specifically, the Department finds that the Company sufficiently demonstrated direct and distinct benefits to ratepayers for four of the non-industry organizations for which it seeks to recover dues and membership costs – the American Benefits Council, the Drug and Alcohol Testing Industry Association, the Electric Utility Industry Sustainable Supply Chain Alliance ("EUISSCA"), and the Northeast Human Resources Association (e.g., the Company's membership in EUISSCA helps it to address supply chain issues) (Exh. ESRR/CCP/Comp-Rebuttal-1, at 13-16). On brief, the Company offers additional detailed explanations of benefits for other non-industry organizations, such as ORC HSE Strategies, LLC (Company Brief at 164-165; Company Reply Brief at 44-45). The evidentiary record, however, contains only the names of these organizations, and not detailed explanations (Exhs. ESRR/CCP/Comp-Rebuttal-1, at 13-16; DPU 15-1& Att.; DPU 38-1 &

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[107] In contrast, the Company provided clear, specific, and detailed customer benefits related to each of its proposed industry dues and memberships (Exh. AG 38-1, at 1-6). For example, Eversource Energy's participation on the Advanced Energy Economy's Utility Advisory Committee fosters understanding of generation and storage solutions to incorporate into long term system planning and supports a clean energy future at the Company (Exh. AG 38-1, at 5).

Att.; DPU 53-1; DPU 53-2 & Att.; AG 8-19, Att.; AG 22-2; AG 38-1). As noted above, it is the Company's burden to establish that these non-industry dues and memberships benefit customers. See, e.g., D.P.U. 92-111, at 127; D.P.U. 92-101, at 54; D.P.U. 90-121, at 151. Simply listing the organizations in a response to an information request seeking substantive information does not satisfy that burden. Nor is it the Department's role to independently verify the nature of each organization and attempt to discern the link between their function and customer benefits.

Based on the foregoing considerations, the Department allows recovery of the costs associated with the four aforementioned organizations for which the Company demonstrated a clear link between costs and ratepayer benefits. The total cost proposed in the Company's cost of service for the American Benefits Council, the Drug and Alcohol Testing Industry Association, EUISSCA, and the Northeast Human Resources Association is $12,113 (Exh. ES-REVREQ-3, WP 12 (Rev. 4)). We disallow recovery of the costs associated with the remaining non-industry memberships, as we conclude that it is inappropriate for ratepayers to fund the costs of non-industry dues and memberships for which the Company has not established a clear and direct link to ratepayer benefits on the record. D.P.U. 20-120, at 329-330. Finally, the Department allows recovery of NSTAR Electric's industry dues and memberships, with the exception of one of the double entries associated with the Company's AIM membership, a reduction of $15,312 (Exh. ES-REVREQ-3, WP 12 (Rev. 4); DPU 53-2, Att.; AG 38-1). Accordingly, the Department reduces the Company's proposed cost of service by $363,166 ($347,854 in disallowed non-industry dues + $15,312 in disallowed industry dues).

F. Caregiver Program

1. Introduction

During the test year, NSTAR Electric booked $85,432 for the Caregiver Program included in its proposed residual O&M expense (Exh. AG 8-10, Att.). Eversource Energy's operating companies implemented the Caregiver Program on July 1, 2019, in response to employee-requested support on storm days (RR-AG-14; Tr. 6, at 686).[108] Under this program, Eversource Energy makes quarterly payments of $51,000, or approximately $20 per employee, to the contractor Care.com for a total pool of 300 backup days available annually for employees (Tr. 6, at 681-682). The Company states that these backup days are available for care of an employee's dependents up to ten days per employee per year in the event of an emergency (Exh. AG 8-10). As part of this benefit, employees also receive a free membership to Care@Work to connect to a network of caregivers for dependent care (Exh. AG 8-10).

2. Positions of the Parties

a. Attorney General

The Attorney General argues that the Company failed to justify that the Caregiver Program costs are reasonable, prudently incurred, and benefit ratepayers (Attorney General

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[108] Employees of NSTAR Electric and Eversource Energy have storm restoration support roles during emergency storm days (Tr. 6, at 683).

Brief at 130; Attorney General Reply Brief at 37, citing Fitchburg Gas and Electric Light Company, 375 Mass. 571, 582-583). She also contends that the Caregiver Program is not standard in the market (Attorney General Reply Brief at 37).

Further, the Attorney General argues that although the Company pays a single flat fee to provide the pool of 300 backup days to all employees, most employees do not use it (Attorney General Reply Brief at 37, citing Tr. 6, at 681). She asserts that the employees only used 18 days in 2019, 210 days in 2020, 90 days in 2021, and, as of July 15, 2022, 49 days in 2022 (Attorney General Reply Brief at 37, citing RR-AG-14). In particular, the Attorney General contends that the Company's employees only used a fraction of the backup days during the COVID-19 pandemic in 2020 (Attorney General Reply Brief at 37). She also claims that the flat fee is only the membership fee and does not cover the actual backup dependent care costs, which employees pay for themselves (Attorney General Reply Brief at 37-38, citing Tr. 6, at 685-686).

Moreover, the Attorney General argues that the Company has not provided documentation or evidence to support its claim that customers benefit from a stable workforce, which the Caregiver Program facilitates (Attorney General Brief at 130, citing Exh. ES-RR/CPP/Comp-Rebuttal-1, at 12). The Attorney General asserts that because NSTAR Electric does not track the number of missed workdays or employees who have left their jobs due to dependent care issues, the Company failed to demonstrate the Caregiver Program provides any impact on employee productivity or employee retention (Attorney General Brief at 130, citing Tr. 6, at 686).

b. Company

The Company argues that the Caregiver Program benefits customers because it provides a safety net that ensures trained employees can perform their work duties to provide safe and reliable service to customers (Company Brief at 173). According to the Company, a recent childcare report issued by the Massachusetts Taxpayer Foundation determined that, due to inadequate childcare, individuals and families lose $1.7 billion in wages from missing work or reducing their hours; employers lose $812 million due to lower productivity and turnover/replacement costs; and Massachusetts forgoes $188 million in tax revenues due to lower earnings and lost wages (Company Brief at 173, citing Exh. ES-RR/CPP/Comp-Rebuttal-1, at 11). NSTAR Electric asserts that the Caregiver Program also benefits customers by facilitating a stable workforce, as the program reduces the number of day employees miss from work when primary care is temporarily unavailable (Company Brief at 173-174). Further, NSTAR Electric contends that 31 percent of large employers offered subsidized caregiving programs like the Company's Caregiver Program to their employees in 2021, and between 25 and 30 percent of the utility companies offer subsidized childcare to their employees (Company Brief at 173, citing Tr. 6, at 695; Company Reply Brief at 41).

The Company also rejects the Attorney General's contention that most employees are not using the Caregiver Program. According to the Company, employees use the Caregiver Program in the event of emergencies to ensure that they are available to report to storm restoration support roles during ERP events (Company Reply Brief at 41, 42, citing Tr. 6, at 683). Finally, NSTAR Electric contends that it has met its burden of proof and burden of production in demonstrating that the costs associated with the Caregiver Program benefit customers, are reasonable, and were prudently incurred (Company Reply Brief at 43).

3. Analysis and Findings

The Company bears the burden of demonstrating that proposed costs benefit Massachusetts ratepayers, are reasonable, and were prudently incurred. D.P.U. 11-01/D.P.U. 11-02, at 323; D.T.E. 03-40, at 140-141; D.P.U. 1699, at 13. This standard applies whether the expenses were incurred at the parent level or at the service company level. The Department has previously stated that the Department may consider allowing Caregiver Program costs if the Company provides convincing evidence substantiating the relationship between the benefit program and ratepayer benefits, and that these benefits are common industry practice and necessary for the Company to stay competitive in attracting skilled employees. D.P.U. 20-120, at 225.

The Company represents that it implemented the Caregiver Program in response its employees' need for dependent care during emergency storm response (Tr. 6, at 683, 686, 696). Most of Eversource Energy employees have a secondary responsibility in storm restoration support roles, in addition to their normal role, during a storm event, such as coordinating food and lodging for the storm restoration team (Tr. 6, at 683, 696). The frequency and severity of major storm events has increased noticeably since 2009, and such storms may arise on short notice when regular dependent care is unavailable (Tr. 6, at 696). Massachusetts Electric Company, Nantucket Electric Company, and NSTAR Electric

Company, D.P.U. 21-75/D.P.U. 21-76, at 22 (2021). The Department finds that by providing backup care during emergency storm response, the Caregiver Program creates stability in the workforce, and therefore provides benefits to ratepayers by enabling the Company to provide safe and reliable service to its customers. Regarding the availability of this benefit across the industry, the Company states that approximately 25 to 30 percent of utility companies offer subsidized childcare to their employees (Tr. 6, at 695). While this percentage may not rise to the level of common industry practice, in this instance, given the importance of providing a stable workforce during emergency storm response and the resulting benefits to customers, the Department allows the $85,432 of costs associated with the Caregiver Program in the Company's residual O&M.

G. Enterprise Information Technology Expense

1. Introduction

Enterprise IT expense represents charges billed to NSTAR Electric for ESC's investments in IT systems that support more than one of the Eversource Energy operating companies (Exh. ES-REVREQ-1, at 72). Enterprise IT projects that support more than one company are installed at the service company level to efficiently implement one integrated solution to be used on a shared basis and to efficiently charge the costs of shared infrastructure across multiple entities (Exh. ES-REVREQ-1, at 72-73). Accordingly, Enterprise IT projects are capitalized by ESC and charged to the operating companies as expense through the general service company overhead rate (Exhs. ES-REVREQ-1, at 53-54, 72-73, 79-80; DPU 48-1; DPU 48-5; AG 1-28 & Att. (c); AG 1-92). ESC's revenue requirement for the Enterprise IT projects is comprised of depreciation expense and a return on ESC's gross investment base less accumulated depreciation and ADIT (Exhs. ES-REVREQ-2, Sch. 14 (Rev. 4); ES-REVREQ-4, Sch. 5(b) (Rev. 3)). ESC allocates 32.44 percent of Enterprise IT costs to NSTAR Electric, which represents the Company's proportionate share of net income and gross plant assets (Exhs. ES-REVREQ-1, at 81; DPU 48-5). This percentage allocator is a total Company allocator that includes transmission; therefore, the Company applies an additional adjustment to remove the portion of the expense attributable to transmission (Exhs. ES-REVREQ-1, at 81; ES-REVREQ-2, Sch. 14 (Rev. 4)). Finally, because ESC employees perform both capital and expense functions for the Company related to the Enterprise IT projects, an ESC expense ratio of 64.05 percent is applied against the total cost for NSTAR Electric, with the remainder charged to capital or other balance sheet accounts and not included in the revenue requirement (Exhs. ES-REVREQ-1, at 81; ES-REVREQ-2, Sch. 14 (Rev. 4); ES-REVREQ-4, Sch. 5(b) (Rev. 3)).

During the test year, the Company booked $33,020,432 in Enterprise IT projects expense (Exh. ES-REVREQ-2, Sch. 14). The Company initially proposed a pro forma increase in Enterprise IT expense of $10,869,443 based on the total estimated revenue requirement associated with: (1) expected changes in Enterprise IT expense through December 31, 2021; and (2) the post-test-year Oracle Utilities Analytics ("OUA")[109] and

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[109] The Company explains that the OUA project will replace the current FocalPoint reporting systems (Exhs. ES-ADDITIONS-1, at 60-61; ES-REVREQ-1, at 75). The implementation of OUA will address outage reporting system limitations by providing

Network Management System ("NMS")[110] capital projects undertaken by ESC in 2022 (Exhs. ES-REVREQ-1, at 73-74; ES-REVREQ-2, Sch. 14). During the proceeding, the Company reduced its proposed Enterprise IT pro forma adjustment to $7,906,029 based on: (1) a revised calculation of ESC's return on the test-year and post-test-year investments to reflect NSTAR Electric's proposed weighted average cost of capital ("WACC") and (2) updates to Enterprise IT project expense for actual 2022 ESC plant activity for the OUA and NMS projects (Exh. ES-REVREQ-2, Sch. 14 (Rev. 1 through 3)). Thus, the Company proposes a total Enterprise IT expense of $40,926,462 (Exh. ES-REVREQ-2, Sch. 14 (Rev. 4)).

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a single, enterprise outage reporting system that is architected to integrate with ESC's enterprise outage management system to provide outage related data in near real-time through a robust, high performance outage reporting platform (Exhs. ES-ADDITIONS-1, at 61; ES-REVREQ-1, at 75-76; AG 12-43).

[110] The Company explains that the NMS project will upgrade the current NMS system to the latest Oracle software version 2.4 in conjunction with the implementation of new server hardware that will enhance system performance and reliability to provide a modernized, technically current software/hardware platform that is fully vendor supported through 2023 (Exhs. ES-ADDITIONS-1, at 63; ES-REVREQ-1, at 77; AG 12-44). Additionally, four high business-value system enhancements, which include Training Simulator, Outage Mobile Application, Automated Single Outage No Light Closeout, and Automated Overlay Google Map Satellite Imagery, will be implemented as part of the NMS project to deliver significant new business capability that directly support and advance operational excellence across ESC (Exhs. ES-ADDITIONS-1, at 63; ES-REVREQ-1, at 77).

2. Positions of the Parties

a. Attorney General

The Attorney General argues that NSTAR Electric failed to timely provide project closure reports to support its Enterprise IT expense, despite the Company's awareness of the Department's specific filing requirements (Attorney General Brief at 131-132, citing Exhs. ES-ADDITIONS-1, at 56-57; AG 15-21 through AG 15-25; D.P.U. 18-150, at 275). The Attorney General contends that the Company acknowledged the delay in providing the closing reports but claimed that all of the required documentation had been provided within six months of the initial filing (Attorney General Brief at 132, citing Exh. ES-RR/CPP/Comp-Rebuttal-1, at 40).

The Attorney General also claims that there are deficiencies with the variance analyses provided by the Company (Attorney General Brief at 132). In particular, the Attorney General asserts that the Company's purported variance analyses contains estimates, revisions, actuals, and the variance amount, but provide no actual analytical detail such as the reason for the variance or which costs contributed to the variance (Attorney General Brief at 132, citing Exh. DPU 69-12, Att. (a); Tr. 1, at 28-30).

The Attorney General argues that NSTAR Electric's failure to provide timely documentation that substantively complies with the Department's filing standards left insufficient time to conduct a meaningful review of costs and raised doubt about the accuracy of the Company's filing (Attorney General Brief at 132-133). Although the Attorney General does not recommend a specific disallowance of costs, she contends that the Department should enforce its existing standards and institute and enforce strong administrative safeguards to prevent similar issues in the future, such as the automatic disallowance of costs for projects for which mandated documentation is not provided with a Company's initial filing (Attorney General Brief at 132-133, citing D.P.U. 18-150, at 274-275). The Attorney General also asserts that the Department should require the following information in variance analyses: (1) original estimates, (2) any updated estimates and the related causes, and (3) detailed explanations for both the causes and amounts of any variances, including proper identification of which costs caused the variance (Attorney General Brief at 133).

The Attorney General argues that, despite the Company's position to the contrary, her recommendations are appropriate as they only seek enforcement of the Department's existing standards (Attorney General Reply Brief at 39-40). Finally, the Attorney General rejects any notion that her recommendations would penalize the Company for circumstances beyond its control (Attorney General Reply Brief at 40). The Attorney General contends that the information required to be submitted with the initial filing includes basic, essential Company-generated and maintained project documentation, and the Department's standard allows for additional supporting documentation to be provided through discovery in a timely fashion no later than the close of discovery (Company Reply Brief at 40, citing D.P.U. 18-150, at 275).

b. Company

NSTAR Electric asserts that it will examine the issues experienced with document production in this proceeding to refine and improve its processes for future filings; however, the Company argues that the automatic disallowance of costs without a showing of imprudence as suggested by the Attorney General is inappropriate and should be rejected (Company Brief at 210). NSTAR Electric contends that the Attorney General's recommendation is impermissibly punitive and could ultimately penalize the Company for circumstances beyond its control, such as when a vendor fails to provide an invoice in a timely fashion for its inclusion in the initial filing (Company Brief at 210). In addition, NSTAR Electric argues that the Attorney General's automatic disallowance recommendation ignores the Department's criteria in D.P.U. 18-150 that requires the Company to produce documentation throughout the course of the discovery period (Company Brief at 210).

Regarding the sufficiency of the information produced in this proceeding, NSTAR Electric claims that it has provided all project documentation supporting its Enterprise IT projects from 2016 through 2021, including Project Authorization Forms and any supplements, approvals, and the appropriate variance analyses for these projects, consistent with the Company's Capital Authorization Policy (Company Brief at 211, citing Exhs. ES-ADDITIONS-11, Atts. (a) through (f); DPU 69-12, Att. (c); RR-AG-11).

Further, NSTAR Electric asserts that it has met the Department's standard for the inclusion of the post-test-year OUA and NMS projects (Company Brief at 209). Specifically, NSTAR Electric contends that both projects are in service and used and useful, the projects advanced the ESC IT strategy and long-term investment plan, project costs were prudently incurred, and no party argued that the costs associated with the projects were imprudent or contrary to the Company's Capital Authorization Policy (Company Brief at 209, citing

Exhs. DPU 48-1; DPU 69-12). In addition, NSTAR Electric claims that the costs were fairly allocated from ESC to the Company (Company Brief at 209, citing Exhs. ES-REVREQ-1, at 72-73, 79-80; DPU 48-1 & Att.; DPU 48-5; AG 1-28 & Att.(c); AG 1-92). While the Company acknowledges that there were delays in providing documentation regarding these projects, the Company maintains that it ultimately provided a comprehensive, consolidated version of the Enterprise IT project documentation during discovery to aid in review of these projects (Company Brief at 209, citing Exhs. ES-REVREQ/CPP/Comp-Rebuttal-1, at 40; DPU 69-12).

3. Standard of Review

The standard for the inclusion of IT expense is comprised of three elements.[111] First, the investments underlying the IT expense must be in service and used and useful. D.P.U. 18-150, at 274, citing D.P.U. 95-118, at 42. Second, the underlying IT investments must be prudently incurred. D.P.U. 18-150, at 274, citing D.P.U. 95-118, at 42. Third, the underlying IT investments must be fairly allocated to the company, with an explanation of how the company and its ratepayers benefit from the investment. D.P.U. 18-150,

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[111] Historically, the Department reviewed a petitioning company's proposed IT expense under the standard of review for lease expense (i.e., reasonableness), as the affiliated service company included IT expense in its lease charges to the petitioning company. D.P.U. 18-150, at 273; D.P.U. 15-155, at 308; D.P.U. 09-39, at 159-159. In D.P.U. 18-150, the Department found that, in conjunction with the increasing importance of IT in business functions, the size and scope of IT investments had become more significant and that this trend likely would continue. D.P.U. 18-150, at 272-273 & n.125. Based on these considerations, the Department found that the lease expense standard of review was no longer sufficient to satisfy the burden of proof necessary for IT-related expense. D.P.U. 18-150, at 273.

at 274-275, citing Hingham Water Company, D.P.U. 88-170, at 21 (1989); Housatonic Water Works Company, D.P.U. 86-93, at 18 (1987); see also Milford Water Company, D.P.U. 12-86, at 11 (2013) (the Department must carefully scrutinize affiliate transactions because the exercise of control and the absence of arm's-length bargaining between affiliated companies can lead to "excessive charges for services, construction work, equipment and materials") (citations omitted); Public Utility Holding Company Act of 1935, P.L. No. 333, 49 Stat. 803, § 1(b)(2), (3) (1935) (Congress recognized concern with allocation of costs within public utility holding company as reason for legislative/regulatory control of holding companies where subsidiary company accounting practices and rates are affected); Report of the Special Commission on Control and Conduct of Public Utilities (1930 H. 1200), at 46 (March 1930) (consumers suffer from excessive charges by affiliates to operating companies). In addition, as part of their initial filings requesting new base distribution rates, petitioning companies must submit the following documentation for each service-company-allocated IT investment: (1) project sanctioning papers; (2) project closure reports; (3) variance analyses explaining the reasons for cost overruns and for demonstrating prudency; (4) project descriptions, including completed analyses enumerating ratepayer benefits and the investment's advancement of company IT strategy; and (5) the company's long-term investment plan. D.P.U. 18-150, at 275. Petitioning companies are also required to amend their initial filing to include documentation associated with post-test-year investments, if applicable. D.P.U. 18-150, at 275.

4. Analysis and Findings

The Department has reviewed the testimony and supporting documentation for the Company's test-year and post-test-year Enterprise IT investments, as well as updates provided during the proceeding, including initial and supplemental project authorization forms, project approvals, project costs, project closing reports, descriptions of ratepayer benefits, and variance analyses (Exhs. ES-REVREQ-1, at 72-73, 79-80; ES-ADDITIONS-1, at 52-65; ES-RR/CPP/Comp-Rebuttal-1, at 39-43; ES-ADDITIONS-8A & Supp.; ES-ADDITIONS-8B & Supp.; ES-ADDITIONS-11; DPU 15-2; DPU 48-1 & Att.; DPU 48-5; DPU 69-5, Att. & Supp. 1; DPU 69-6, Att. & Supp.; DPU 69-12 & Atts. (a) through (f)[112]; AG 1-28 & Att. (c); AG 1-92; Tr. 1, at 21-39, 65-68; RR-AG-1). We find that the test-year and post-test-year Enterprise IT projects are in-service, used and useful, the costs were prudently incurred, and the Company provided a reasonable explanation of the benefits to ratepayers (Exhs. DPU 48-1; DPU 69-12, Atts. (a), (c, parts 1-21)). For example, customers benefit from the proposed Enterprise IT investments because the systems are necessary for the provision of electric service to customers and they are less expensive for any individual operating company, including NSTAR Electric, when the systems undertaken within a cost-sharing framework (e.g., undertaken by ESC on behalf of the

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[112] At the Company's request, Exh. DPU 69-12, Att. (a) replaces Exhs. ES-ADDITIONS-9 & Rev.; Exh. DPU 69-12, Att. (b) replaces Exhs. ES-ADDITIONS-9 (Supps. 1 and 2); and Exh. DPU 69-12, Att. (c), parts 1 through 28 replace Exhs. ES-ADDITIONS-10, ES-ADDITIONS-10A, and ES-ADDITIONS-10 (Supps. 1 and 2).

operating companies on a shared basis) (Exh. DPU 48-1). In addition, the Company's post-test-year OUA and NMS projects are in service, used and useful, and the costs of these projects were prudently incurred, with actual costs through June 30, 2022, being less than the estimated costs for these projects (Exhs. ES-ADDITIONS-8A & Supp; ES-ADDITIONS-8B & Supp.; DPU 69-5, Att. (Supp. 1); DPU 69-6, Att. (Supp. 1); DPU 69-12, Atts. (b), (c, parts 22-28); Tr. 1, at 30-31, 38).[113]

Further, we find that the test-year and post-test-year Enterprise IT project costs were fairly allocated to NSTAR Electric based on the Company's proportionate share of net income and gross plant assets (Exhs. ES-REVREQ-1, at 80-81; ES-REVREQ-2, Sch. 14 (Rev. 4); DPU 48-5; AG 1-28 & Att. (c); AG 1-92). The allocation is based on the Company's operations portfolio designation, which is largely asset driven and uses the referenced allocator (Exh. DPU 48-5). Lastly, the Company provided a summary of its IT long-term investment plan (Exh. DPU 48-1, Att.).

The Company acknowledges its challenges and delays in providing project documentation for Enterprise IT projects throughout this proceeding and concedes that it bears the burden to fully support its requests for cost recovery with appropriate

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[113] The Company outlines numerous business and operational benefits associated with the implementation of the OUA and NMS systems (Exhs. ES-REVREQ-1, at 76, 78-79; ES-ADDITIONS-1, at 61-62, 63-64). Any potential savings resulting from these systems would be recognized in the future, and, therefore, they are not currently quantifiable or included in the cost of service (see Exh. AG 14-6). The Department expects NSTAR Electric to reflect potential future savings in the Company's next base distribution rate case.

documentation (Company Brief at 210). The Department recognizes that there are acceptable circumstances when not all required documentation may be available at the time of a company's initial filing. For example, as described above, two of NSTAR Electric's Enterprise IT projects in the instant proceeding were placed in service several months following its initial filing, and, therefore, the Company was unable to provide closing reports for these projects with the initial filing (Tr. 1, at 30-31, 38). Our standard for the inclusion of IT expense costs recognizes that petitioners are required to amend their initial filing to include documentation associated with post-test-year investments, if applicable. D.P.U. 18-150, at 275.

The Department notes, however, that while NSTAR Electric ultimately provided the required documentation to support the recovery of the costs associated with its Enterprise IT projects, the Company did not provide all the required documentation with its initial filing, was required to submit supplements and revisions to numerous exhibits, inadvertently omitted certain information from exhibits, and often requested multiple extensions of time to respond to information requests regarding Enterprise IT projects (*see*, *e.g.*, Exhs. ES-ADDITIONS-8A & Supp.; ES-ADDITIONS-8B & Supp.; ES-ADDITIONS-9 & Rev., Supps.; ES-ADDITIONS-10 & Supps.; ES-ADDITIONS-10A; DPU 69-12 & Atts.). Further, the Company's need to develop a "roadmap" mid-proceeding to facilitate the Department's and intervenors' review of the Enterprise IT documentation highlights the Company's difficulties in providing complete information in a timely, organized manner (Exhs. ES-RR/CPP/Comp-Rebuttal-1, at 40-41; DPU 69-12 & Atts.).

Despite the Company's shortcomings in providing the Enterprise IT projects supporting documentation, we find that the Attorney General and other parties nevertheless had sufficient opportunity to review the documentation, issue discovery, conduct meaningful cross-examination at the evidentiary hearings, and present any objections to cost recovery for Department consideration (see, e.g., Exhs. AG-LA-1, at 4-8; AG 14-5; AG 14-6; AG 4-18; AG 12-43; AG 12-44; AG 24-6, AG 24-7; Tr. 1, at 21-39, 65-68; RR-AG-1; Attorney General Brief at 131-133; Attorney General Reply Brief at 39-40). As such, in this instance, we will not disallow any test-year or post-test-year Enterprise IT investments. Further, we are not persuaded that additional directives are necessary for future filings, such as the automatic disallowance of costs recommended by the Attorney General.

The Department does, however, reaffirm our requirements related to IT project documentation and reminds companies that it is critical for complete and detailed IT-related investment documentation to be submitted in a timely fashion so that the Department and intervenors have sufficient time for review. Specifically, as part of initial filings requesting new base distribution rates, petitioning companies must submit the following documentation for each service company-allocated IT investment: (1) project sanctioning papers; (2) project closure reports; (3) variance analyses explaining the reasons for cost overruns and for demonstrating prudency; (4) project descriptions, including completed analyses enumerating ratepayer benefits and the investment's advancement of company IT strategy; and (5) the petitioning company's long-term investment plan. D.P.U. 18-150, at 275. Further, variance analyses must contain original estimates, any updated estimates, detailed explanations for both the causes and amounts of variances, and identification of which costs caused the variance. Petitioning companies can amend initial filings to include documentation associated with post-test-year investments, if applicable. All additional supporting documentation provided through discovery should be produced in a timely fashion and no later than at least one week prior to the close of discovery.

Finally, consistent with Department precedent, for the return component of the Company's Enterprise IT project expenses, the Department calculates the WACC using the capital structure and ROE approved in this Order. D.P.U. 20-120, at 293-294; D.P.U. 19-120, at 255-256; D.P.U. 18-150, at 270-271. Using the capital structure and ROE approved in this proceeding produces an overall WACC of 7.06 percent and a pre-tax WACC of 9.02 percent. Application of the Company's approved pre-tax WACC to ESC's allocation of Enterprise IT expense results in a decrease of $52,095 to the proposed rate year expense (see Exh. ES-REVREQ-2, Sch. 14, at 2 (Rev. 4)). Accordingly, the Department decreases the Company's proposed cost of service by $52,095 for an approved increase to Enterprise IT expense of $7,853,934.

H. Incremental COVID-19 Expenses

1. Introduction

In response to the COVID-19 pandemic, the Department allowed each gas and electric company to record, defer, and track their incremental pandemic-related response costs, subject to a final determination as to their appropriate ratemaking treatment. D.P.U. 20-58-D/D.P.U. 20-91, Interim Order on Ratemaking Proposal and Vote and Order

Opening Investigation at 22-23 (December 31, 2020). Consistent with these rulings, Eversource Energy established affiliate-specific accounting work orders to identify and track incremental non-labor COVID-19 related expenses, such as costs associated with employee protection processes and equipment, facilities cleaning, maintaining the workforce at remote locations, certain telecommunication expenses, and other related costs (Exhs. DPU 3-1; DPU 19-4 & Att.; DPU 56-2).

As of December 31, 2020 (i.e., the end of the test year), NSTAR Electric had incurred total COVID-19-related expenses of \$8,848,163, of which \$7,907,079 was allocated to distribution operations (Exh. DPU 3-2, Att.). The Company also identified COVID-19-related cost savings of \$379,940 that were allocated to distribution operations, producing a net COVID-19-related expense of \$7,527,139 (Exhs. DPU 3-2; DPU 56-1).[114] Of the \$7,909,079 in distribution-related expenses, the Company identified \$4,675,470 as nonrecurring and thus eligible for deferral (Exhs. DPU 3-2; AG 1-34, Att. (h) at 7; AG 1-34, Att. (i) at 5; AG 21-1, Att.). The \$7,909,079 in total distribution-related expenses, less \$4,675,470 in deferrals, produced a total remaining COVID-19 expense allocated to distribution operations of \$3,231,610 (Exhs. DPU 3-2; AG 21-1, Att.; DPU 56-1).

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[114] Cost savings represent expenses that had been avoided as the result of suspended work activities. D.P.U. 20-58-D/D.P.U. 20-91, Interim Order on Ratemaking Proposal and Vote and Order Opening Investigation at 15 (December 31, 2020). The Company's calculations were based on the \$7,907,079 total distribution-related expense and did not factor in the \$379,940 cost savings (see Exhs. DPU 3-2; DPU 56-1).

NSTAR Electric initially included $3,231,610 in COVID-19-related expenses in its proposed cost of service (Exhs. DPU 56-1; AG 13-2). During the proceeding, the Company revised its estimate of ongoing COVID-19 response costs from $3,231,610 to $988,000, based on a review of its 2022 internal operating budgets (Exh. AG 13-2; RR-DPU-13). These expenses consist of: (1) $362,000 in additional facilities cleaning costs; (2) $75,000 in additional HVAC operation; (3) $380,000 in additional IT costs; and (4) $171,000 in telephone expenses for customer service representatives continuing to work from home (Exhs. DPU 56-2; AG 13-2). The Company states that because its operations have changed as a result of the pandemic experience, these additional expenses will continue to be incurred for the foreseeable future and have thus been incorporated in the Company's cost of service (Exhs. DPU 3-2; ES-REVREQ-2, Sch. 9, at 1 (Rev. 4)). The Company excluded the remaining $2,243,610 from its proposed cost of service (Exh. ES-REVREQ-2, Sch. 9, at 1 (Rev. 4)).

2. Positions of the Parties

a. Attorney General

The Attorney General accepts NSTAR Electric's revised estimate of $988,000 in ongoing incremental COVID-19 responses costs as appropriate (Attorney General Brief at 119, citing Exhs. ES-RR/CPP/Comp-Rebuttal-1, at 31-32; AG-DJE-Surrebuttal-1, at 2). Therefore, the Attorney General accepts the Company's proposed reduction of $2,243,610 to its test year cost of service (Attorney General Brief at 119).

b. Company

NSTAR Electric maintains that it has appropriately identified its recurring COVID-19 response costs (Company Brief at 219, citing Exh. DPU 56-2; RR-DPU-13). The Company also states, as noted by the Attorney General, that it has appropriately eliminated non-recuring COVID-19 response expenses from its proposed cost of service (Company Brief at 219-220, citing Exh. ES-REVREQ-2 (Rev. 2).

3. Analysis and Findings

The Department's long-standing precedent allows only known and measurable changes to test-year expenses to be included in a company's cost of service. D.T.E. 98-51, at 61-62, citing Dedham Water Company, D.P.U. 84-32, at 17 (1984). Further, the Department permits a company to include expenses in its cost of service if a company can demonstrate that the expense is either annually or periodically recurring or, if non-recurring, is extraordinary in nature and amount as to warrant their collection by amortizing them over an appropriate time period. D.P.U. 1270/1414, at 33; see also D.P.U 89-114/90-331/91-80 (Phase One) at 152; Western Massachusetts Electric Company, D.P.U. 88-250, at 65-67 (1989).

The Department has previously recognized that the COVID-19 pandemic has caused not only a public health emergency, but also a significant economic disruption to both customers and jurisdictional gas, electric, and water distribution companies throughout the country. D.P.U. 20-58, Order Opening Inquiry and Establishing Working Group at 2 (May 11, 2020); D.P.U. 20-58-A, Order on Customer Outreach Plan at 5 (June 26, 2020).

While utilities in general faced shifts in demand and usage, increased operational burdens, collections shortfalls, and voluntary and mandatory moratoriums on disconnections, their employees also faced significant disruptions in their day-to-day working conditions. These disruptions necessitated remote work arrangements for those employees whose duties could be performed remotely, including access to IT that an individual employee would not be reasonably expected to personally possess (Exh. DPU 3-2). Because a significant number of employees are considered essential workers who do not have the ability to work remotely, the Company continued to incur facilities cleaning expenses to comply with the cleaning guidelines prescribed by the Center for Disease Control ("CDC") as well as to ensure safe workspaces for its employees (Exh. DPU 3-2). With changes in CDC cleaning protocols and transitions to more of a hybrid work environment in 2021 and thereafter, the Department is satisfied that the test-year expense is not representative of the Company's ongoing COVID-19 response costs that will be incurred in the future. Nonetheless, we recognize that some level of additional COVID-19 response costs will continue to be incurred for an indefinite time.

The Department has examined the Company's calculations and assumptions behind its proposed $988,000 in ongoing COVID-19 response expenses (Exh. DPU 56-2; Tr. 3, at 279-281; RR-DPU-13). The recurring facility cleaning and maintenance costs of $362,000 consists of: (1) $166,000 in increased cleaning of high-traffic areas and touch points identified for each of the Company's Massachusetts facilities; (2) $177,000 in janitorial overtime calculated for each facility; and (3) $19,000 in costs associated with stocking the approximately 150 sanitation stations located at these facilities (Exh. DPU 56-2; Tr. 3, at 277-278; RR-DPU-13). The recurring electricity costs of $75,000 are associated with additional run times for HVAC equipment based on both CDC and professional engineering guidelines, with a partial offset for lower base electricity costs versus pre-pandemic consumption levels (Exh. DPU 56-2; Tr. 3, at 279-280; RR-DPU-13). The recurring IT costs of $380,000 assume a 25 percent reduction from 2021 expenses as employees transition from remote work to in-office work (Exh. DPU 56-2; Tr. 3, at 280; RR-DPU-13). The recurring customer service costs of $171,000 are based on the Company's allocated share of the $501,120 in increased costs associated with approximately 200 Eversource customer service agent expenses working 20 days a month (Exh. DPU 56-2; Tr. 3, at 279-281; RR-DPU-13). Based on our review, the Department finds that the $988,000 identified by the Company as ongoing COVID-19 response costs is more representative of its ongoing expenses than test-year expense. Aquarion Water Company of Massachusetts, D.P.U. 11-43, at 182-183 (2012); D.P.U. 10-55, at 445. The Department also finds that these costs represent a known and measurable change to test-year cost of service. See D.P.U. 10-55, at 445; D.P.U. 09-30, at 211; D.P.U. 08-35, at 108; Oxford Water Company, D.P.U. 88-171, at 13-14 (1989). Accordingly, the Department allows the $988,000 identified by the Company as ongoing COVID-19 response costs.

I. Employee Retention Credit

1. Introduction

The Coronavirus Aid, Relief, and Economic Security Act of 2020 established an employee retention credit ("ERC") to incentivize companies to retain employees during the

COVID-19 pandemic (RR-AG-2).[115] The ERC operates in the form of a payroll tax credit that is claimed on an employer's quarterly Form 941 tax filings; during 2020, the credit was equal to 50 percent of up to $10,000 in qualified wages paid to an employee (RR-AG-2). While NSTAR Electric had not yet received any of these credits during the test year, the Company booked the expected credits to be received for the years 2020 and 2021 to Account 408, Payroll Taxes (Exh. AG 11-12). The Company estimated that its share of ERCs for 2020 was $1,823,800 (Exh. AG 11-12).

NSTAR Electric considered the ERC credits to be non-recurring because they were not expected to be available in the future, and therefore removed the anticipated ERC credit from its test-year cost of service (Exhs. ES-REVREQ-1, at 58; ES-REVREQ-2, Sch. 9 (Rev. 4); Tr. 1, at 85-86). This adjustment resulted in an increase of $1,823,800 to its test-year cost of service (Exhs. ES-REVREQ-2, Sch. 9 (Rev. 4); ES-RR/CCP/Comp-Rebuttal-1, at 34; AG 21-5).

2. Positions of the Parties

a. Attorney General

The Attorney General contends that the treatment of the ERC in this proceeding should be consistent with the treatment applied in D.P.U. 20-91 (Attorney General Brief at 120; Attorney General Reply Brief at 35). The Attorney General reasons that if the ERC

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[115] Section 206 of the Taxpayer Certainty and Disaster Tax Relief Act of 2020, enacted as Division EE of the Consolidated Appropriations Act, 2021, modified the provisions of the ERC and extended its application to July 1, 2021. Pub. L. No. 116-260, 134 Stat. 1182 (December 27, 2020).

was a credit to expense and was non-recurring, then it should be eliminated from the determination of the Company's revenue requirement (Attorney General Brief at 119-120). Further, the Attorney General argues that for consistency, if the Department eliminates the ERC from NSTAR Electric's revenue requirement here, then the ERC must also be eliminated from any level of COVID-19 expense that the Company is ultimately authorized to recover in D.P.U. 20-91 (Attorney General Brief at 120; Attorney General Reply Brief at 35).

b. Company

NSTAR Electric argues that it has appropriately eliminated the effects of the ERC on its cost of service (Company Brief at 220, citing Exhs. AG 11-12; AG 11-22; AG 13-4; AG 21-5; Tr. 1, at 83-86; RR-AG-2; Company Reply Brief at 40-41). According to the Company, because the ERC was not included as an offset in its request to recover incremental COVID-19 costs in D.P.U. 20-91, the ERC must be removed from cost of service to avoid an improper reduction to cost of service (Company Brief at 220, citing RR-AG-2). The Company notes that it will offset any COVID-19 response costs that are ultimately authorized in D.P.U. 20-91 with the ERC (Company Reply Brief at 40-41).

3. Analysis and Findings

The Department typically includes a test year level of expenses in cost of service and will adjust this level only for known and measurable changes. Milford Water Company, D.P.U. 17-107, at 104 (2018), citing D.P.U. 11-01/D.P.U. 11-02, at 345; D.P.U. 07-71, at 120; D.P.U. 87-260, at 75. In this regard, the Department has consistently held that there are three classes of expenses that are recoverable through base rates: (1) annually recurring expenses; (2) periodically recurring expenses; and (3) nonrecurring extraordinary expenses. D.P.U. 17-107, at 104-105, citing D.P.U. 11-01/D.P.U. 11-02, at 345; D.T.E. 98-51, at 35; D.P.U. 95-118, at 121-122; D.P.U. 1270/1414, at 32-33.

The provisions of the ERC expired, with some limited exceptions not applicable to the Company, during the fourth quarter of 2021.[116] Consequently, the Department finds that the ERC is a nonrecurring credit to payroll taxes, and that its inclusion in the Company's cost of service would produce a distorted level of payroll tax expense. See, e.g., Aquarion Water Company of Massachusetts, D.P.U. 17-90, at 247-248 (2018). Further, we find that the Company has properly calculated the necessary adjustment to its proposed cost of service (Exhs. ES-REVREQ-2, Sch. 8, at 2 (Rev. 4); AG 11-12; AG 11-22; AG 21-5; Tr. 1, at 83-86; RR-AG-2). Therefore, the Department accepts the Company's proposed adjustment, and we remove the ERC from the Company's test-year cost of service. The elimination of this credit produces an increase of $1,823,800 to the Company's test-year cost of service (Exhs. ES-REVREQ-2, Sch. 9 (Rev. 4); ES-RR/CCP/Comp-Rebuttal-1, at 34; AG 21-5).

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[116] See Internal Revenue Bulletin: 2021-65, Termination of the Employee Retention Credit Under Section 3134 of the Code in the Fourth Calendar Quarter of 2021 for Certain Employers.

J. Work Asset Management Expenses

1. Introduction

As part of Eversource Energy's technology modernization initiatives, it has embarked on the implementation of a new Work and Asset Management System ("WAM System") across all of its electric transmission and distribution operations, including those of the Company (Exh. ES-ADDITIONS-10, at 1059; Tr. 7, at 766-767). During the test year, NSTAR Electric booked approximately $3,200,000 in expenditures associated with the implementation of the WAM System to Account 921, Office Supplies and Expenses (Exh. DPU 3-14). These expenses represented the cost of employee training intended to familiarize Company personnel with the use of the WAM System (Exh. AG 16-15).

2. Positions of the Parties

a. Attorney General

The Attorney General argues that the WAM System training expenses are nonrecurring and should be excluded from the Company's proposed cost of service (Attorney General Brief at 117; Attorney General Reply Brief at 35). In support of her position, the Attorney General contends that once the Company's employees are appropriately trained on the use of the WAM System, these training costs should not be expected to continue (Attorney General Brief at 117). The Attorney General also contends that the Company's Account 921 expenses for 2021 decreased by an amount similar to what would be expected if the WAM System training costs were removed and were consistent with the 2019 expenses when adjusted for inflation and "some level" of continuing costs related to COVID-19

(Attorney General Brief at 117-118, citing Exhs. AG DJE-1, at 6-7; AG 1-2, Att. (6)(e) at 170 (Supp. 1)).

Further, the Attorney General dismisses the Company's claim that it has incurred significant training expenses during the first quarter of 2022 as a non sequitur unsupported by any evidence (Attorney General Brief at 118). She points out that during Department questioning, the Company was unable to confirm whether the increase in expenses booked to Account 921 during the first quarter of 2022 was attributable to training costs (Attorney General Brief at 118, citing Tr. 7, at 764; Attorney General Reply Brief at 35)

Based on the nature of the Company's test-year WAM System training expenses and lack of evidence that the Company's test-year Account 921 expenses are representative of future expenditures, the Attorney General argues that the Company's proposed WAM System training expenses are nonrecurring (Attorney General Brief at 118; Attorney General Brief at 35). Thus, she asserts that the Company's proposed cost of service should be reduced by $2,777,920, which represents the portion of the $3,200,000 in total expenses associated with distribution operations (Attorney General Brief at 119, citing Exh. AG DJE-1, at 7, Sch. 1).[117]

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[117] The Attorney General calculates that, after factoring in working capital, return requirements, and income taxes, her proposed adjustment produces an overall reduction of $3,038,162 to the Company's proposed cost of service (Exh. AG DJE-1, at 7, Sch. 1).

b. Company

NSTAR Electric argues that while the WAM System training costs are not in themselves a recurring expense, the Company continually conducts other trainings across its organization to ensure that employees and contractors are able to perform their duties consistent with Company systems, procedures, and processes (Company Brief at 211, citing Exhs. ES-RR/CPP/Comp-Rebuttal-1, at 32; AG 16-15). For example, the Company maintains that although there are no incurred or forecasted WAM System training expenses for 2022 and 2023, its overall Account 921 expenses during 2021 were $6,939,589, and were $6,471,458 during the first quarter of 2022 (Company Brief at 211, citing Exhs. ES-RR/CPP/Comp-Rebuttal-1, at 32-33; AG 21-4). The Company contends that it will continue to incur training expenses, including training on a range of IT platforms that ESC is developing over the next four years (Company Brief at 211, citing Exh. ES-RR/CPP/Comp-Rebuttal-1, at 33; Company Reply Brief at 39, citing Exhs. DPU 48-1; ES-ADDITIONS-8A at 2-3). The Company argues that because training costs are recurring, its test-year WAM System training costs provides an appropriate representative expense to be included in the cost of service (Company Brief at 212, citing Exh. ES-RR/CPP/Comp-Rebuttal-1, at 33; Tr. 7, at 766-769).

In the alternative, NSTAR Electric proposes that if the Department determines that its WAM System training costs are not representative, then the expenses should be normalized rather than eliminated in their entirety (Company Reply Brief at 39-40). According to the Company, normalization places a certain degree of risk back on the utility that would be expected in the course of operations (Company Reply Brief at 40, citing D.P.U. 92-101, at 48-49; D.P.U. 92-78, at 9; D.P.U. 1720, at 89). The Company proposes that if the Department declines to allow the test-year expense in full, a normalization period of four years would be appropriate in view of the relatively short life associated with IT (Company Reply Brief at 39 n.5, citing Bay State Gas Company, D.P.U. 13-75, at 261-263 (2014)).

3. Analysis and Findings

Test-year expenses that recur on an annual basis are eligible for full inclusion in cost of service unless the record supports a finding that the level of the expense in the test year is abnormal. D.P.U. 1270/1414, at 33. The Department's longstanding policy regarding adjustments to O&M expense levels is to set a representative level of expenses that are reasonably expected to recur on a normal annual basis. D.P.U. 1270/1414, at 33.

Account 921 encompasses a wide range of expenditures, representing office supplies and expenses incurred in connection with the general administration of the utility's operations that are assignable to specific administrative or general departments, and not specifically provided for in other accounts. 18 CFR Part 101, Account 921. Examination of the Company's bookings to Account 921 and its related subaccounts for the years 2018 through 2021 indicates that the most significant activity occurs in three subaccounts, with a fourth subaccount acting as a clearing account (Exhs. DPU 3-14; AG 1-2, Att. (6)(e) at 170 (Supp. 1); AG 1-34, Atts. (d) at 25, (e) at 18-19, (f) at 26, (g) at 19, (h) at 27, (i) at 19-20, (k) at 27 (Supp. 1), and (l) at 20 (Supp. 1)). While the Company points to the significant increase in its Account 921 expenses for the first quarter of 2022, the Company was unable to quantify the reasons for this increase aside from generalized observations about other training programs (Tr. 7, at 765, 768-769). Moreover, the magnitude of the reported increase (i.e., more than doubling test-year expense on an annualized basis) is suggestive of some unusual activity during that period. On this basis, the Department finds that there is insufficient evidence to support consideration of the Company's expense levels for the first quarter of 2022 in assessing the representativeness of its test-year Account 921 expenses.

While the Department acknowledges that utilities engage in employee training on an ongoing basis, the WAM expenses are nonrecurring, and the Company has failed to demonstrate that its test-year Account 921 expenditures are representative of the level of expense that will be incurred in the future. Therefore, the Department finds it appropriate to remove the test-year WAM expenses from the Company's proposed cost of service. D.P.U. 10-55, at 332-333; D.P.U. 08-35, at 120-125.[118] Of the $3,200,000 in test year WAM expenses, the Company allocates 13.19 percent, or $422,080, to its transmission operations (Exhs. AG-DJE-1, at 7, Sch 1; DPU 3-2, Att.). The remaining 86.81 percent, or $2,777,920, represents the portion associated with distribution operations (Exhs. DPU 3-2, Att.; AG-DJE-1, at 7, Sch. 1). Accordingly, the Department reduces the Company's proposed cost of service by $2,777,920.

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[118] NSTAR Electric's alternative proposal to normalize the WAM System training expenses was offered on reply brief. We find the proposal to be untimely, as neither the Department nor the remaining parties had an opportunity to conduct meaningful investigation.

K. Rate Case Expense

1. Introduction

Initially, the Company estimated that it would incur $3,816,170 in rate case expense (Exhs. ES-REVREQ-1, at 100; ES-REVREQ-2, Sch. 19). Based on its final invoices and projected costs to complete the compliance filing, the Company proposes a total rate case expense of $3,108,191 (Exhs. ES-REVREQ-2, Sch. 19 (Rev. 4); DPU 30-8, Att. A (Supp. 3)). NSTAR Electric's proposed rate case expense includes costs related to legal representation, rate case support, and expert consulting services related to the Company's (1) PBR proposal, (2) depreciation study, (3) cost of capital study, and (4) allocated cost of service ("ACOSS") study (Exhs. ES-REVREQ-1, at 94-95, 100; ES-REVREQ-3, WP 19; AG 5-35, Att. A; DPU 30-1).[119]

The Company proposes to normalize the rate case expense over a five-year period based on the statutory requirement (Exhs. ES-REVREQ-1, at 100; ES-REVREQ-2, Sch. 19 (Rev. 4); DPU 30-21). Normalizing the Company's proposed rate case expense of $3,108,191 over five years produces an annual expense of $621,638 (Exh. ES-REVREQ-2, Sch. 19 (Rev. 4)).

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[119] The Company utilized ESC or internal employees as witnesses for certain aspects of the rate case, such as revenue requirement, employee compensation and benefits, and rate design, as well as legal support. The payroll costs for these employees are included in employee compensation and benefits rather than in rate case expense (Exh. DPU 30-11; Tr. 14, at 1507).

2. Positions of the Parties

The Company maintains that it appropriately conducted a competitive solicitation process consistent with the Department's requirements (Company Brief at 198-199). The Company also asserts that it has taken steps to control rate case expense, including selecting outside service providers that provided blended hourly fees, discounts, and not-to-exceed levels (Company Brief at 199, citing Exhs. DPU 30-3; DPU 30-17). In addition, NSTAR Electric maintains that it performs a detailed review of the outside service providers' invoices and resolves any questions or anomalies prior to approving for payment (Company Brief at 199-200, citing Exh. DPU 30-17). No intervenor addressed the Company's rate case expense on brief.

3. Analysis and Findings

a. Introduction

The Department allows recovery for rate case expense based on two important considerations. First, the Department permits recovery of rate case expense that actually has been incurred and, thus, is considered known and measurable. New England Gas Company, D.P.U. 10-114, at 219-220 (2011); D.P.U. 07-71, at 99; D.T.E. 05-27, at 157; D.T.E. 98-51, at 61-62. Second, such expenses must be reasonable, appropriate, and prudently incurred. D.P.U. 10-114, at 220; D.P.U. 09-30, at 226-227; D.P.U. 95-118, at 115-119.

The overall level of rate case expense among utilities has been, and remains, a matter of concern for the Department. D.P.U. 10-114, at 220; D.P.U. 07-71, at 99; D.T.E. 03-40, at 147; D.T.E. 02-24/25, at 192; D.P.U. 93-60, at 145. Rate case expense, like any other expenditure, is an area in which companies must seek to contain costs. D.P.U. 10-114, at 220; D.P.U. 07-71, at 99; D.T.E. 03-40, at 147-148; D.T.E. 02-24/25, at 192; D.P.U. 96-50 (Phase I) at 79. All companies are on notice that the risk of non-recovery of rate case expenses looms should they fail to sustain their burden to demonstrate cost containment associated with their selection and retention of outside service providers. D.P.U. 10-114, at 220; D.P.U. 09-39, at 289-293; D.P.U. 09-30, at 238-239; D.T.E. 03-40, at 152-154. Further, the Department has found that rate case expenses will not be allowed in cost of service where such expenses are disproportionate to the relief being sought. D.P.U. 10-114, at 220; D.P.U. 10-55, at 323; see also Barnstable Water Company, D.P.U. 93-223-B at 16-17 (1993).

b. Competitive Bidding Process

i. Introduction

The Department has consistently emphasized the importance of competitive bidding for outside services in a petitioner's overall strategy to contain rate case expense. See, e.g., D.P.U. 10-114, at 221; D.P.U. 09-30, at 227; D.T.E. 05-27, at 158-59; D.T.E. 03-40, at 148; D.T.E. 02-24/25, at 192. If a petitioner elects to secure outside services for rate case expense, it must engage in a competitive bidding process for these services. D.P.U. 10-114, at 221; D.P.U. 09-30, at 227; D.P.U. 07-71, at 99-100, 101; D.T.E. 03-40, at 153. In all but the most unusual of circumstances, it is reasonable to expect that a company can comply with a competitive bidding requirement. D.P.U. 10-55, at 342. The Department fully expects that competitive bidding for outside rate case services, including legal services, will be the norm. D.P.U. 10-55, at 342.

The requirement of having to submit a competitive bid in a structured and organized process serves several important purposes. First, the competitive bidding and qualification process provides an essential, objective benchmark for the reasonableness of the cost of the services sought. D.P.U. 10-114, at 221; D.P.U. 09-30, at 228-229; D.P.U. 07-71, at 101; D.T.E. 03-40, at 152. Second, it keeps even a consultant with a stellar past performance from taking the relationship with a company for granted. D.P.U. 10-114, at 221; D.P.U. 07-71, at 101; D.T.E. 03-40, at 152. Finally, a competitive solicitation process serves as a means of cost containment for a company. D.T.E. 03-40, at 152-153.

The competitive bidding process must be structured and objective and be based on a RFP process that is fair, open, and transparent. D.P.U. 10-114, at 221, 224; D.P.U. 09-30, at 227-228; D.P.U. 07-71, at 99-100; D.T.E. 03-40, at 153. The timing of the RFP process should be appropriate to allow for a suitable field of potential service providers to provide complete bids and provide the company with sufficient time to evaluate the bids. D.P.U. 10-114, at 221; D.P.U. 10-55, at 342-343. Further, the RFP issued to solicit service providers must clearly identify the scope of work to be performed and the criteria for evaluation. D.P.U. 10-114, at 221-222; D.P.U. 10-55, at 343.

The Department does not seek to substitute its judgment for that of a petitioner in determining which service provider may be best suited to serve the petitioner's interests and obtaining competitive bids does not mean that a company must necessarily retain the services of the lowest bidder regardless of its qualifications. D.P.U. 10-114, at 222; D.T.E. 03-40, at 153. The need to contain rate case expense, however, should be accorded a high priority in the review of bids received for case work. D.P.U. 10-114, at 222; D.T.E. 03-40, at 153. In seeking recovery of rate case expenses, companies must provide an adequate justification and showing, with contemporaneous documentation, that their choice of outside services is both reasonable and cost-effective. D.P.U. 10-114, at 222; D.T.E. 03-40, at 153.

ii. Company's RFP Process

The Company seeks to include expenses associated with the following: (1) PBR proposal; (2) depreciation study; (3) cost of capital study; (4) ACOSS study; (5) legal services; and (6) rate case support (Exhs. ES-REVREQ-1, at 94-95, 100; ES-REVREQ-3, WP 19; DPU 30-1; DPU 30-8, Att. A (Supp. 3); DPU 30-18). NSTAR Electric provided documentation demonstrating that it conducted a competitive bidding process for each of its service providers utilized solely for this base distribution rate proceeding (Exhs. DPU 30-1 & Atts.; DPU 30-7; DPU 30-18; DPU 50-2). The Company also utilized a managed services program vendor who conducted analysis and prepared documentation supporting the filing of exhibits related to capital additions as well as administrative support in submitting filings pursuant to a competitive bidding process that was conducted in 2017 (Exhs. DPU 30-7; DPU 30-18).

Based on our review of the RFPs and responses, we conclude that the Company's choices regarding its consultants, including attorneys, were reasonable and cost effective (Exhs. DPU 30-1, Atts. (h) through (l); DPU 30-2 & Atts.; DPU 30-3 & Att.). We also find that NSTAR Electric appropriately considered price and non-price factors before selecting the providers that it determined would provide the best combination of price and appropriate quality of service (Exhs. DPU 30-1, Atts. (h) through (l); DPU 30-2 & Atts.; DPU 30-3 & Att.). For each category, the Company appropriately selected a provider that possessed expertise and experience, knowledge of Department ratemaking precedent and practice, familiarity with the Company's operations, and a comprehensive understanding of the tasks for which it was requested to bid (Exhs. DPU 30-1, Atts. (h) through (l); DPU 30-2 & Atts.; DPU 30-3 & Att.). Based on the foregoing, the Department concludes that NSTAR Electric conducted a fair, open, and transparent competitive bidding process for the attorneys and consultants (Exhs. DPU 30-1, Atts. (h) through (l); DPU 30-2 & Atts.; DPU 30-3 & Att.).

c. Various Rate Case Expenses

The Department has directed companies to provide all invoices for outside rate case services that detail the number of hours billed, the billing rate, and the specific nature of the services performed. D.P.U. 10-114, at 235-236; D.T.E. 03-40, at 157; D.T.E. 02-24/25, at 193-194. The Department has reviewed the invoices provided by NSTAR Electric and finds that the invoices are properly itemized (see, e.g., Exhs. DPU 30-8, Atts. B through G; DPU 30-8, Atts. E, F (Supp. 3)). In addition, the Department finds that the total costs associated with each service provider are reasonable, appropriate, and proportionate to the overall scope of work provided and were prudently incurred (see, e.g., Exhs. DPU 30-8, Atts. B through G; DPU 30-8, Atts. E, F (Supp. 3)).

d. Normalization of Rate Case Expense

The proper method to calculate a rate case expense adjustment is to determine the rate case expense, normalize the expense over an appropriate period, and then compare it to the test-year level to determine the adjustment. D.P.U. 10-55, at 338-339; D.T.E. 05-27, at 163; D.T.E. 03-40, at 163; D.T.E. 02-24/25, at 197; D.T.E. 98-51, at 62; D.P.U. 95-40, at 58. The Department's practice is to normalize rate case expense so that a representative annual amount is included in the cost of service. D.P.U. 10-55, at 339; D.T.E. 05-27, at 163; D.T.E. 03-40, at 163; D.T.E. 02-24/25, at 191; D.T.E. 01-56, at 77; D.T.E. 98-51, at 53; D.P.U. 96-50 (Phase I) at 77. Normalization is not intended to ensure dollar-for-dollar recovery of a particular expense; rather, it is intended to include a representative annual level of expense. D.P.U. 10-55, at 339; D.T.E. 05-27, at 163; D.T.E. 03-40, at 163-164; D.T.E. 02-24/25, at 191; D.P.U. 96-50 (Phase I) at 77.

Typically, the Department determines the appropriate period for recovery of rate case expense by taking the average of the intervals between the filing dates of a company's last four base distribution rate cases, including the present case, rounded to the nearest whole number. D.P.U. 10-55, at 339; D.T.E. 05-27, at 163 n.105; D.T.E. 03-40, at 164 n.77; D.T.E. 02-24/25, at 191. If the resulting normalization period is deemed unreasonable or if the company has an inadequate rate case filing history, the Department will determine the appropriate normalization period based on the particular facts of the case. South Egremont Water Company, D.P.U. 86-149, at 2-3 (1986).

NSTAR Electric proposes a five-year rate case expense normalization period based on the period for filing rate cases pursuant to Massachusetts law (Exhs. ES-REVREQ-1, at 101-102; DPU 50-2). The Company also provided a calculation of the average interval between its last four base distribution rate cases, which resulted in an average interval of ten years (Exh. ES-REVREQ-4, Sch. 3).[120] In its calculation, NSTAR Electric did not include any base distribution rate cases involving the former WMECO. Utilizing both NSTAR Electric's and the former WMECo's filings, the average interval between the Company's last four base distribution rate cases is seven years (Exh. ES-REVREQ-4, Sch. 3).[121] As discussed in Section IV.D.5.a above, the Department has approved a PBR plan for the Company that includes a five-year term and stay-out provision. The Department has considered the term of a PBR in establishing an appropriate rate case expense normalization

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[120] In addition to the current filing, NSTAR Electric's prior base distribution rate filings were D.P.U. 17-05, Boston Edison Company/Cambridge Electric Light Company/Commonwealth Electric Company/NSTAR Gas Company, D.T.E. 05-85 (2005), and D.P.U. 92-250 (Exh. ES-REVREQ-4, Sch. 3, at 1). Between D.P.U. 22-22 and D.P.U. 17-05, the interval is 4.99 years; between D.P.U. 17-05 and D.T.E. 05-85, the interval is 11.11 years; and between D.T.E. 05-85 and D.P.U. 92-250, the interval is 13.06 years. The sum of these intervals divided by three and rounded to the nearest whole number results in a normalization period of ten years (29.18/3 = 9.73).

[121] The former WMECo's prior base distribution rate fillings were D.P.U. 17-05, D.P.U. 10-70, and Western Massachusetts Electric Company, D.T.E. 06-55 (2007). Between D.P.U. 22-22 and D.P.U. 17-05, the interval is 4.99 years; between D.P.U. 17-05 and D.P.U. 10-70, the interval is 6.53 years; and between D.P.U. 10-70 and D.T.E. 06-55, the interval is 3.72 years. The sum of these intervals divided by three and rounded to the nearest whole number results in a normalization period of five years (15.24/3 = 5.08). The average of NSTAR Electric's interval and the former WMECo's interval is 7.41 years (rounded to seven).

period. D.P.U. 17-05, at 281-282; D.P.U. 09-30, at 241; D.P.U. 07-71, at 105; D.T.E. 05-27, at 163-164; D.T.E. 03-40, at 163; D.T.E. 01-56, at 75; D.P.U. 96-50 (Phase I) at 78. The Department has found that the term of a PBR that prevents a company from filing a new base distribution rate case for a predetermined period provides a more representative basis for establishing a rate case expense normalization period. D.P.U. 17-05, at 282; D.P.U. 96-50 (Phase I) at 78. Accordingly, the Department finds that a five-year normalization period is appropriate.

e. Conclusion

The Company proposed and the Department has accepted a final rate case expense of $3,108,191 (Exhs. ES-REVREQ-2, Sch. 19 (Rev. 4); DPU 30-8 (Supp. 3), Att. A). Based on a five-year normalization period, the annual level of rate case expense to be included in the Company's cost of service is $621,638 ($3,108,191 divided by five years). The annual level of rate case expense approved in this proceeding is reflected in Schedule 2 below.

VIII. EXCESS ACCUMULATED DEFERRED INCOME TAXES

A. Introduction

On December 22, 2017, the Tax Cuts and Jobs Act of 2017 ("2017 TCJA") was signed into law.[122] Among other things, the 2017 TCJA reduced the federal corporate income tax rate from 35 percent to 21 percent, effective January 1, 2018. Pub. L. No. 115-97, § 13001. On February 2, 2018, the Department, pursuant to G.L. c. 164, §§ 76,

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[122] Pub. L. No. 115-97, 131 Stat. 2054: An Act to provide for reconciliation pursuant to titles II and V of the concurrent resolution on the budget for fiscal year 2018.

93, 94 and G.L. c. 165, §§ 2, 4, opened an investigation into the effect on rates of the decrease in the federal corporate income tax rate on the Department's regulated utilities. Effect of Reduction in Federal Income Tax Rates on Rates Charged by Electric, Gas, and Water Companies, D.P.U. 18-15, Order Opening Investigation (February 2, 2018).[123]

The Department determined, among other things, that for certain regulated utilities, including the Company, the reduction in the federal corporate income tax rate resulted in booked ADIT that was in excess of future liabilities. D.P.U. 18-15, Order Opening Investigation at 4. Thus, as part of the investigation, certain regulated utilities, including the Company, were directed to file a proposal to refund to ratepayers the balance of excess ADIT as of December 31, 2017. D.P.U. 18-15, Order Opening Investigation at 5.

The Department subsequently directed NSTAR Electric to refund excess ADIT to ratepayers through a 2017 Tax Act Credit Factor ("2017 TACF") as a separate reconciling component in the Company's annual rate adjustment/reconciliation filing. D.P.U. 18-15-E at 38-39. The Department determined that the credit factor would remain in effect until the excess ADIT balance is transferred to the new rates that are established in the Company's next base distribution rate proceeding, or unless otherwise directed by the Department. D.P.U. 18-15-E at 39 n.34.

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[123] For a complete background and procedural history, refer to D.P.U. 18-15-A at 1-7.

B. Company Proposal

NSTAR Electric states that its excess ADIT balance as of December 31, 2021, was $428,741,374[124] before tax gross-up and $589,902,826 after tax gross-up (Exhs. ES-REVREQ-2, Sch. 32 (Rev. 4); DPU 51-7). From this amount, the Company deducted a flow-through adjustment of $57,583,262 for items that are primarily depreciation flow-through, and income tax deficiency amounts prior to the 2017 TCJA rate change (Exhs. DPU 18-2; DPU 51-7). Overall, the Company reports a grossed-up net excess ADIT balance of $532,319,565 at year-end 2021 (Exhs. ES-REVREQ-2, Sch. 1, at 4, Sch. 32 (Rev. 4); DPU 51-7).

The Company proposes to continue refunding excess ADIT related to the 2017 TCJA to customers through the 2017 TACF (Exh. ES-REVREQ-1, at 143). As such, the Company does not propose any excess ADIT-related adjustments to the cost of service in this proceeding (Exh. ES-REVREQ-1, at 143). No party addressed the Company's excess ADIT proposal on brief.

C. Analysis and Findings

In D.P.U. 18-15-E, at 39, the Department found that given that NSTAR Electric would refund excess ADIT to ratepayers through its annual rate adjustment/reconciliation filing, the amounts are subject to reconciliation once the final tax liabilities come due. Further, we noted that we fully expected NSTAR Electric to make these determinations as

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[124] Of this amount, $47,637,826 was attributable to non-property related excess ADIT, and $381,103,548 was attributable to property-related excess ADIT (Exh. DPU 51-7).

soon as practicable and to implement appropriate adjustments, supported by testimony and exhibits, in future reconciliation filings. In the instant proceeding, the Company has provided total excess ADIT to be refunded to customers as a result of the 2017 TCJA and shown that it tracked the difference between the excess ADIT amortization and the actual refunds through 2017 TACF over time since the D.P.U. 18-15-E decision (Exhs. DPU 18-4, Att.; DPU 32-1 & Att.; DPU 61-14). Further, the Department finds the Company's reported excess ADIT balances to be acceptable (Exh. DPU 51-7).

As noted above, the Department previously directed NSTAR Electric to refund excess ADIT to ratepayers through the 2017 TACF until the Company could transfer the excess ADIT balance to new rates established in the Company's next base rate proceeding, or unless otherwise directed by the Department. D.P.U. 18-15-E, at 39 n.34. In support of its proposal to continue refunding excess ADIT through the 2017 TACF instead of transferring the balance to base distribution rates, the Company points to Budget of the U.S. Government for Fiscal Year 2023, wherein the Administration seeks to raise the federal corporate income tax rate from 21 percent to 28 percent (Exh. DPU 32-3 & Att. at 40, 135). While a change in this tax rate is not certain, if a change does occur the Company would be required to adjust the excess ADIT balance and amortization periods applicable to ensure an accurate refund to customers. We find that it would be administratively efficient for the Company to address future adjustments to the excess ADIT balance and amortization periods through the 2017 TACF. Moreover, the record shows that the balance of unprotected, non-property-related excess ADIT will be fully refunded to customers by the end of the rate year (Exh. DPU 18-4, Att.; Tr. 1, 140-141). Thus, we find that it would be inappropriate to include the balance in base distribution rates for at least the next five years. Based on these considerations, the Department finds that it is reasonable and appropriate for the Company to retain the 2017 TACF. See D.P.U. 18-150, at 197-198 (allowing National Grid (electric) to retain its tax credit provision due to potential changes Internal Revenue Service normalization requirements).[125] Accordingly, we allow the Company's proposal.

IX. PENSION ADJUSTMENT FACTOR ALLOCATION AND MOTION FOR APPROVAL OF REQUEST FOR ORAL ARGUMENT

A. Introduction

Prior to February 1, 2018, NSTAR Electric recovered a portion of its pension and PBOP expense in its base distribution rates (Exh. ES-REVREQ-7, at 2). See also D.P.U. 17-05, at 323 & n.166; NSTAR Pension, D.T.E. 03-47-C at 7 n.2 (2004).[126] Because a portion of pension and PBOP expense were embedded in base distribution rates, the Company needed to allocate these embedded expenses between its distribution and

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[125] If there is a change in the federal corporate income tax rate that necessitates any adjustments to the excess ADIT balance or amortization amounts, the Department may consider opening an investigation to address the change.

[126] NSTAR Electric and the former WMECo were separate companies until January 1, 2018, when WMECo was consolidated into NSTAR Electric after approval of the transaction by the Department. D.P.U. 17-05, at 4, 43-44. While a portion of NSTAR Electric's pension and PBOP expenses were recovered through base distribution rates, all of WMECo's qualified pension plan pension and PBOP costs were recovered through its own PAM. D.P.U. 17-05, at 323. In D.P.U. 17-05, the Department approved the transfer of all of NSTAR Electric's qualified pension plan pension and PBOP costs to the pension adjustment factor. D.P.U. 17-05, at 324.

transmission functions. D.T.E. 03-47-B (Phase II) at 10-11. During this time, the Company relied on a transmission allocator in its calculation of its proposed pension adjustment factors ("PAF") that varied from year to year to recognize the actual expense allocated to its transmission function based on FERC's formula rate that uses a labor allocator (Exh. ES-REVREQ-7, at 3-7). In contrast, according to the Company, the Attorney General has advocated the use of a fixed ratio of 3.84 percent using the allocation between its distribution and transmission embedded expenses in base distribution rates based on the ratio originally established for NSTAR Electric in D.T.E. 03-47 (Exh. ES-REVREQ-7, at 3).

Although the allocation issue has been resolved for the Company's post-2018 PAF filings, the allocation issue continues to affect eight PAF filings covering the years 2011 through 2018 that are currently pending before the Department. The outstanding dockets are: NSTAR Electric Company and NSTAR Gas Company, D.P.U. 11-91; NSTAR Electric Company and NSTAR Gas Company, D.P.U. 12-113; NSTAR Electric Company and NSTAR Gas Company, D.P.U. 13-184; NSTAR Electric Company and NSTAR Gas Company, D.P.U. 14-145; NSTAR Electric Company, NSTAR Gas Company, and Western Massachusetts Electric Company, D.P.U. 15-147; NSTAR Electric Company, NSTAR Gas Company, and Western Massachusetts Electric Company, D.P.U. 16-182; NSTAR Electric Company, NSTAR Gas Company, and Western Massachusetts Electric Company, D.P.U. 17-159; and NSTAR Electric Company and NSTAR Gas Company, D.P.U. 18-121.

According to the Company, the Attorney General has challenged the recovery of approximately $26,835,250 in pension costs, including carrying charges, in these dockets

(Exh. ES-REVREQ-7, at 3). The Company notes that the allocation issue has been outstanding for over ten years and maintains that lack of resolution of the issue is creating significant regulatory uncertainty (Exh. ES-REVREQ-7, at 2-3). NSTAR Electric states that the Department's resolution of this impasse is needed in this case before the Company can commit to take on the risk of a ten-year PBR Plan (Exh. ES-REVREQ-7, at 2-3).

On September 2, 2022, the Company filed its initial brief in this proceeding. In its brief, the Company addressed the pension allocation issue and requested oral argument before the full Commission because the Department did not inquire about the issue during the discovery or evidentiary hearing phase of the proceeding (Company Brief at 374-380). No other party briefed this issue. On September 7, 2022, the Company filed a Motion for Approval of Request for Oral Argument on this pension allocation issue ("Motion").[127] On September 23, 2022, the Attorney General filed an Opposition to NSTAR Electric's Motion ("Attorney General Opposition").

B. Positions of the Parties

1. Company

NSTAR Electric contends that the pension allocation issue has been unresolved for over a decade, and that the contested amount currently stands at approximately $26.8 million,

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[127] The Motion is a five-page document without pagination. For purposes of the form of motions and briefs filed with the Department, the Department adopts the requirements for pagination of briefs of the Massachusetts Rules of Appellate Procedure, Rule 20(a)(5) (consecutive page numbering). For purposes of cites to the Motion in this Order, the Department identifies the page where the content appears.

including $8.4 million in carrying costs (Motion at 3; Company Brief at 374-375). The Company asserts that given this magnitude of potential exposure, the Department must resolve the pension allocation issue so that the Company and Attorney General can decide on the appropriate next steps, including seeking judicial review if so determined (Motion at 5; Company Brief at 375-376).[128]

NSTAR Electric defends its use of a variable transmission allocator, arguing that its use was designed to match the annual ratio of transmission and distribution expenses in the PAM with the actual ratio of transmission and distribution expense approved by FERC in setting transmission rates (Company Brief at 375). Further, NSTAR Electric contends that the use of a variable transmission allocator was approved by the Department as part of the Company's compliance filing in D.T.E. 03-47.[129]

The Company also contends that it properly incorporated the allocation of pension/PBOP expense into the PAF formula (Company Brief at 376-379). In addition, the Company maintains that the Attorney General is not seeking to correct a computational error in the PAF formula, but rather seeks to modify the PAF formula itself (Company Brief at 379). According to the Company, the Massachusetts Supreme Judicial Court has repeatedly held that a mechanically applied formula rate is a fixed rate that cannot be

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[128] NSTAR Electric contends that if the Department were to decide against the Company on this issue, then it would seek judicial review on the basis of reversible legal error (Company Brief at 375).

[129] The Company's brief makes reference to D.T.E. 03-87, which pertains to a double-pole proceeding, and, therefore, appears to be a typographical error.

changed outside of a base distribution rate proceeding, as had been done in D.P.U. 17-05 (Company Brief at 380, citing Attorney General v. Department of Public Utilities, 453 Mass. 191 (2009)).

In support of its Motion, the Company asserts that the complexity of the method to allocate annual pension expense for the PAM necessitates oral argument to ensure that: (1) the issues are fully litigated on the record; (2) all parties have an opportunity to make a complete presentation of their respective positions; and (3) any questions that the Department may have about the parties' positions are thoroughly addressed and examined before a decision is made (Motion at 4). According to the Company, there is no record in this proceeding beyond the initial filing addressing the allocation method for annual pension expense for the PAM between distribution and transmission, the Department did not ask any questions about this issue during the conduct of this proceeding, and the Company has not had the opportunity to fully defend its position given the limited, pointed questions raised by the Attorney General (Motion at 4). Further, NSTAR Electric contends that there are multiple, complex issues of law to address that require counsel to interpret the Company's assertions (Motion at 4). Thus, the Company argues that there is a lack of defined evidence outlining the pension allocation issue on the record, and it is unreasonable and unfair to adjudicate the matter without of allowing oral argument by the parties (Motion at 4).

2. Attorney General

The Attorney General argues that the open PAF dockets are the appropriate forum for the Company to make its arguments (Attorney General Opposition at 3). Further, the

Attorney General contends that the Company has mischaracterized her position as to the pension allocation issue (Attorney General Opposition at 3). According to the Attorney General, in the PAF dockets, she did not advocate for a fixed 3.84-percent allocation factor, but instead argued that the Company erred in its calculation of the PAF and needs to adjust the transmission allocator within the PAF where the pension and PBOP currently in rates enters into the calculation (Attorney General Opposition at 5). The Attorney General contends that her recommendation would only require corrective calculation of the Company's PAF, which can be achieved in the PAF dockets and is not required to be addressed in this instant base distribution rate case (Attorney General Opposition at 4-5).

The Attorney General also argues that the Motion is untimely and unsupported by a showing of good cause to excuse the delay (Attorney General Opposition at 2-3, citing 220 CMR 1.01(4), 1.02(5), 1.11(2)). Further, the Attorney General contends that, if granted, the Motion would result in oral argument being held after the briefing period, thereby denying intervenors an opportunity to appropriately respond to arguments raised at the hearing (Attorney General Opposition at 3). Thus, the Attorney General asserts that the Motion should be denied (Attorney General Opposition at 3).

C. Analysis and Findings

The Department first will address the Motion. The Department's regulations governing requests for oral arguments can be in found in 220 CMR 1.11(2), which provides:

> Oral Argument, When Made. When, in the opinion of the presiding officer, time permits and the nature of the proceedings, the complexity or importance of the [issues] of fact or law involved, and the motion or at the request of a party or staff counsel at or before the close of the taking of testimony, allow

> and fix a time for the presentation of oral argument, imposing such limits of time on the argument as deemed appropriate in the proceeding. Such argument shall be transcribed and bound with the transcript of testimony.

The decision to allow for oral argument is completely within the Department's discretion. Bay State Gas Company, Interlocutory Order on Appeal of Hearing Officer Ruling on Intervention, D.P.U. 16-12, at 8 n.6 (March 8, 2016); The Berkshire Gas Company, D.P.U. 15-178, Interlocutory Order on Appeal of Hearing Officer Ruling on Intervention and Motion for Clarification at 8 n.6 (February 17, 2016); The Berkshire Gas Company, D.P.U. 15-48, Interlocutory Order on Motion to Stay and Appeals of Hearing Officer Ruling on Intervention at 15 n.6 (June 19, 2015); NSTAR Electric Company, D.P.U. 12-19, at 10 n.10 (2012); D.P.U. 11-43, at 6, 9. Further, the Department finds no statutory right to oral argument before an administrative agency.[130]

As an initial matter, the Motion was filed approximately six weeks after the close of hearings, and the Company provides no reason for this inordinate delay. As such, we find the Motion is untimely. Nevertheless, even if the Motion was made within the time prescribed by 220 CMR 1.11(2), the Department finds that the Company did not demonstrate that oral argument is warranted in this proceeding. NSTAR Electric's prefiled initial testimony, supporting appendix, initial brief, and Motion provided ample background

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[130] The Massachusetts Administrative Procedures Act, G.L. c. 30A, contains no such right. Further, the Department does not find that due process interests require oral argument. See, e.g., Federal Communications Commission v WJR, The Goodwill Station, Inc., 337 U.S. 265, 275 (1949) (due process law as guaranteed by the Fifth Amendment does not require federal administrative agencies to accord oral argument).

information and Company commentary on the pension allocation issue (Exhs. ES-REVREQ-1, at 209-210; ES-REVREQ-7; Company Brief at 374-380; Motion at 2-5). Further, the remaining parties had the opportunity to issue discovery, conduct cross-examination of witnesses, file comments, and respond to the Motion to address the pension allocation issue. Oral argument was not necessary to flesh out the issues. Based on these considerations, the Motion is denied.

Notwithstanding our findings above, the Department will address the issue of NSTAR Electric's pension allocation in the pending PAF dockets. Three cases, D.P.U. 11-91, D.P.U. 12-113, and D.P.U. 13-184, have been fully briefed by both the Company and the Attorney General. The Attorney General has submitted prefiled testimony in D.P.U. 14-145, D.P.U. 15-147, D.P.U. 16-182, D.P.U. 17-159, and D.P.U. 18-121. Given the procedural posture of the Company's PAF proceedings, including the evidentiary record developed to date, the Department finds that it is more appropriate and efficient to continue to adjudicate the pension allocation issue in those open dockets.[131] Accordingly, the Department declines to examine NSTAR Electric's pre-2018 pension allocations in this Order.

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[131] Given the nature of the unresolved issue and in the exercise of its discretion, the Department will consider whether oral argument in any of these open dockets is necessary.

X. STORM COST RECOVERY MECHANISM

A. Introduction

The parameters of NSTAR Electric's current storm cost recovery mechanism ("storm fund") were approved in the Company's last base distribution rate proceeding, D.P.U. 17-05. In particular, the Department: (1) established that a storm-fund-eligible event must meet a $1.2 million incremental O&M cost threshold; (2) set the annual storm fund contribution collected through base distribution rates at $10 million; (3) approved an annual O&M expense associated with storm events of $3.6 million; (4) approved a symmetrical cap of $30 million on the storm fund balance; (5) approved the accrual of carrying charges at the prime rate for storm-fund-eligible events, with recovery to begin at the time that the costs are incurred; and (6) allowed the Company to seek cost recovery through the exogenous cost provision of the PBR mechanism (pending a prudence review) provided that the combination of any single storm in excess of $30 million and balance of the storm fund exceeds $75 million. D.P.U. 17-05, at 547-559. The Department also established reporting requirements to allow for expedited and efficient review of the Company's storm-cost filings and for an evaluation of the prudency of storm-related costs. D.P.U. 17-05, at 562.

B. Company Proposals

1. Storm Fund Modifications

The Company proposes to continue its storm fund mechanism with four modifications. First, the Company proposes to increase the storm-fund-eligible event threshold to $1.3 million in incremental O&M costs (Exhs. ES-CAH/DPH-1, at 98; ES-REVREQ-1, at 162). NSTAR Electric states that its proposal is based on increasing the current threshold of $1.2 million by the cumulative inflation change of the GDP-PI, as reported by the U.S. Bureau of Economic Analysis, from 2016 through 2020 (Exhs. ES-REVREQ-1, at 163; DPU 4-7. Att.).

Second, the Company proposes to increase the annual storm fund contribution collected through base distribution rates to $31 million (Exhs. ES-CAH/DPH-1, at 98; ES-REVREQ-1, at 162, 181; ES-REVREQ-2, Sch. 22 (Rev. 4)). According to the Company, its current annual storm fund allowance of $10 million is insufficient, given the large disparity between the annual average of incremental O&M costs related to storm-fund-eligible events experienced during the last several years and the amount currently amortized through base distribution rates (Exh. ES-REVREQ-1, at 163). The Company states that its proposal is based on the average monthly storm costs of approximately $2.6 million incurred between February 1, 2018 (the date that rates established in D.P.U. 17-05 were implemented) through the end of the test year, multiplied by twelve months (Exhs. ES-REVREQ-1, at 181; ES-REVREQ-2, Sch. 22 (Rev. 4)).

Third, NSTAR Electric proposes to increase the annual O&M expense associated with storm events to $7.8 million (Exh. ES-REVREQ-1, at 164-164). The Company bases this proposal on the average number of storm-fund-eligible events from 2017 through 2020, which were six events on average, multiplied by the proposed storm-fund-eligible event threshold of $1.3 million (Exhs. ES-CAH/DPH-1, at 98; ES-REVREQ-1, at 164-165; AG 12-6).

Fourth, NSTAR Electric proposes that, for each storm-fund-eligible event subsequent to the seventh event in a calendar year, the Company is permitted to recover the storm-fund-eligible event threshold of $1.3 million through the storm fund (Exhs. ES-CAH/DPH-1, at 98; ES-REVREQ-1, at 162, 165-166, 169-170; DPU 34-1). Conversely, if there are less than five storm-fund-eligible events in a calendar year, customers would receive a $1.3 million credit for the number of events less than five that did not occur (Exhs. ES-CAH/DPH-1, at 98; ES-REVREQ-1, at 162, 169-170; DPU 34-1).

2. Other Proposals

In addition to the proposed modifications to the storm fund, the Company sets forth three additional proposals. First, the Company proposes to recover the current storm-fund-eligible event threshold of $1.2 million for six storm-fund-eligible events that occurred in 2020 and seven storm-fund-eligible events that occurred in 2021, for a total of $15.6 million in costs (Exh. ES-REVREQ-1, at 173; Company Reply Brief at 49).

Second, NSTAR Electric proposes to maintain its current storm cost adjustment recovery factor ("SCRAF") and to recover, beginning on January 1, 2023, and subject to a future prudence review and reconciliation, a portion of the Company's outstanding storm fund deficiency of approximately $106 million over a five-year period for an annual amortization amount of $21.2 million (Exhs. ES-REVREQ-1, at 178-180; DPU 4-8, Att. (b)).[132]

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[132] Currently, the Company recovers an annual amortization amount of $28 million through the SCRAF for costs associated with storm-fund-eligible events that occurred prior to February 1, 2018 (Exh. ES-REVREQ-1, at 178). On December 31, 2022,

Third, the Company proposes to recover through the SCRAF beginning on January 1, 2024, subject to future prudence review and reconciliation, $196.2 million in costs associated with two exogenous storm events – Tropical Storm Henri and the October 2021 Nor'easter (Exhs. ES-REVREQ-1, at 179-180; ES-REVREQ-4, Sch. 11(d); DPU 4-8, Att. (c); DPU 4-13).[133] The Company proposes to recover the costs for these two storm events over a five-year period for annual amortization amount of $39.2 million (Exhs. DPU 4-8, Att. (c), at 1; DPU 4-13; DPU 4-14 & Att.).

C. Positions of the Parties

1. Attorney General

The Attorney General argues that NSTAR Electric's storm cost recovery proposals improperly attempt to insulate the Company from all storm-related financial risk (Attorney General Brief at 133, citing D.P.U. 15-155, at 83; D.P.U. 09-39). In particular, the Attorney General recommends that the Department reject four of the Company's proposals.

First, the Attorney General argues that Company's proposal to increase the annual storm fund contribution collected through base distribution rates to $31 million represents a significant shift of financial risk to ratepayers (Attorney General Brief at 138). Moreover, the Attorney General contends that the Company's request is unnecessary because it can

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the amortization period associated with these storms expires (Exh. ES-REVREQ-1, at 178).

[133] The Company notes that the amortization of the exogenous cost currently collected through the SCRAF expires on December 31, 2023 (Exhs. ES-REVREQ-1, at 179; DPU 4-13, at 1).

recover additional storm costs through the existing SCRAF, which the Company proposes to extend in the instant proceeding (Attorney General Brief at 138, citing Exh. ES-REVREQ-1, at 181).

Second, the Attorney General argues that NSTAR Electric's proposal to recover the storm-fund-eligible event threshold of $1.3 million for each storm after the seventh storm also seeks to eliminate the Company's storm-related financial risk (Attorney General Brief at 137, citing D.P.U. 15-155, at 78). In this regard, the Attorney General contends that NSTAR Electric already is insulated from the cost-risk of storms due the large number of storm cost recovery mechanisms approved for the Company in recent years (Attorney General Brief at 138, citing D.P.U. 17-05, at 547-548, 550, 553-555, 559, 561, 562, NSTAR Electric Company, D.P.U. 21-133; D.P.U. 21-75/D.P.U. 21-76; NSTAR Electric Company, D.P.U. 20-29). Moreover, the Attorney General asserts that NSTAR Electric earns an ROE that, in part, is intended to compensate the Company for such risks (Attorney General Brief at 138). Finally, the Attorney General asserts that maintaining a fixed number of storm-fund-eligible event threshold amounts in base distribution rates is a fair and reasonable way to balance financial risk between the Company and its ratepayers (Attorney General Brief at 137).

Third, the Attorney General argues that NSTAR Electric's request to recover the storm-fund-eligible event threshold amounts for the six storm events in 2020[134] should be

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[134] The Attorney General does not address the Company's request to recover the storm-fund-eligible event threshold amounts attributable to seven storms in 2021.

rejected because it contravenes the Department's Order in D.P.U. 17-05, it would retroactively alter the entire regulatory treatment of storm costs and storm fund cost eligibility, and it would improperly rebalance the risk for storm recovery in the Company's favor (Attorney General Brief at 135-136, citing D.P.U. 17-05, at 548-549; Attorney General Reply Brief at 41-43). Further, the Attorney General contends that if NSTAR Electric's proposal is allowed, it would triple the recovery currently allowed in base distribution rates and would represent one-and-a-half times the amount the Company proposes to include in base distribution rates going-forward (Attorney General Reply Brief at 41). In addition, the Attorney General asserts that approving this proposal would allow the Company to consistently recover storm-related costs when such costs exceed the representative amount set in base distribution rates, with no corresponding path for ratepayers to benefit in the years when costs are less than those in base distribution rates (Attorney General Reply Brief at 43).

Finally, the Attorney General argues that the Department should reject the Company's proposal to recover costs associated with Tropical Storm Henri and the October 2021 Nor'easter (Attorney General Brief at 139). The Attorney General asserts that this proposal should be rejected because the Company has not yet provided supporting documentation or costs for Department review (Attorney General Brief at 139).

2. Company

The Company contends that storms are more common due to changes in weather patterns and climate change and are more costly due to expectations (customer and political) that compel more rapid restorations (Company Brief at 312). According to the Company, these circumstances are beyond its control and are creating an unpreventable increase in the cost of storm response (Company Brief at 312). As such, the Company requests that the Department consider the proposed modifications to the storm fund structure (Company Brief at 312-318). Further, the Company asserts that its proposal to maintain the SCRAF is in the best interest of ratepayers as it serves to minimize carrying charges that ultimately will be recovered for the storm fund qualifying events which, in turn, mitigate bill impacts and maintain stabilized rates (Company Brief at 320-323). The Company's responses to the four arguments raised by Attorney General are discussed below.

First, the Company argues that its proposal to increase the annual storm fund contribution collected through base distribution rates to $31 million does not represent a significant shift of risk to ratepayers (Company Brief at 331). Rather, the Company contends that its proposal meets the Department's objective of maintaining a sufficient reserve in the storm fund for the benefit of both the Company and its customers (Company Brief at 331). The Company further asserts that to maintain a balance between storm cost recovery and rate stability, the annual storm fund contribution collected through base distribution rates is designed to recover qualifying storm costs while eliminating rate changes (Company Brief at 331, citing Exhs. ES-STORMS-Rebuttal-1, at 22; AG 12-7).

Second, the Company argues that its proposal to recover the storm-fund-eligible event threshold of $1.3 million for each storm after the seventh storm should be approved, as it is a reasonable and an appropriate means of balancing risk and cost-sharing between the Company and its customers (Company Brief at 317-318, 330, citing Exhs. ES-STORMS-Rebuttal-1, at 14-15; DPU 20-3). The Company contends that this proposal recognizes the inevitable year-to-year variability of storm-fund-eligible events, as well as the fact that larger-scale events may occur that can exceed any number of storms that the Department would find appropriate for setting the threshold (Company Brief at 317-318). Further, the Company asserts that the proposal is symmetrical, so that if there is a deviation resulting in a lower number of storms in a year, customers would be credited with the storm-fund-eligible event threshold (Company Brief at 318). Nevertheless, the Company claims that, while fewer than six storm-fund-eligible events could occur in any given year, it is more likely that the number of storm events in any year will exceed six (Company Brief at 329).[135]

Third, NSTAR Electric argues that the Department specifically permitted the Company to propose an appropriate level of recovery associated with the storm-fund-eligible event threshold amounts for the six storm events in 2020 (Company Brief at 325-326, citing D.P.U. 21-75/D.P.U. 21-76, at 28). Further, the Company contends that allowing recovery through base distribution rates of the storm-fund-eligible thresholds for three storm events, as approved in D.P.U. 17-05, is an ineffective means of determining a representative number of storm-fund-eligible storms due to the increasing frequency and intensity of storms (Company Brief at 326-327, citing D.P.U. 17-05, at 546; D.P.U. 21-75/D.P.U. 21-76, at 22; Company Reply Brief at 48). According to the Company, the actual number of storm-fund eligible

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[135] The Company notes that since 2020, the number of qualifying storm fund events has exceeded the number of storm-fund-eligible event thresholds included in base distribution rates as the representative number of such storms (Company Brief at 329, citing Exhs. ES-STORMS-Rebuttal-1, at 8; DPU 20-3).

storm occurrences in a given year exceeds the number of storms the Department has historically allowed in base distribution rates (Company Reply Brief at 47). Thus, the Company asserts that there is no imbalance in allowing the recovery of storm-fund-eligible event thresholds over the representative number of storms established in D.P.U. 17-05 (Company Brief at 328). Based on these considerations, the Company seeks recovery of the storm-fund-eligible event threshold amounts for six storm events in 2020, and for seven additional storm events in 2021 (Company Brief at 327-328; Company Reply Brief at 48). The Company argues that disallowing these costs without a finding that the costs were unreasonably incurred is not an appropriate outcome (Company Reply Brief at 47).

Finally, NSTAR Electric disagrees with the Attorney General's recommendation to deny the Company's proposal to recover costs associated with Tropical Storm Henri and the October 2021 Nor'easter (Company Brief at 332, citing Attorney General Brief at 139). The Company argues that it is important to begin cost recovery of these storm events on January 1, 2024, in order to strike an appropriate balance between cost recovery and rate stability (Company Brief at 332, citing Exh. DPU 4-14). In this regard, the Company contends that a delay in recovery of these costs would create significant fluctuations in customer rates as well as significant carrying charges (Company Brief at 332, citing Exhs. DPU 4-14; AG 20-3). For these reasons, the Company asserts that the Department should approve cost recovery commencing January 1, 2024, associated with Tropical Storm Henri and the October 2021 Nor'easter (Company Brief at 332).

D. Analysis and Findings

1. Introduction

The Department's primary objective for allowing a storm fund is to levelize the recovery of storm restoration costs of major storms on ratepayers. D.P.U. 17-05, at 545; D.P.U. 15-155, at 73; Fitchburg Gas and Electric Light Company, D.P.U. 13-90, at 13 (2014), citing D.P.U. 10-70, at 201-202; D.P.U. 09-39, at 206. The Department has recognized that the use of storm funds may shift the burden of cost recovery disproportionately to ratepayers without providing commensurate benefits. D.P.U. 17-05, at 545; D.P.U. 15-155, at 73; D.P.U. 13-90, at 13. As such, the Department has put all EDCs on notice that if they seek continuation of a storm fund in their next base distribution rate case, they must demonstrate why the continuation of a storm fund is in the best interest of ratepayers. D.P.U. 17-05, at 545; D.P.U. 15-155, at 73-74; D.P.U. 13-90, at 14-15.

2. Continuation of the Storm Fund

The Department has devoted significant time and resources to the improvement of each electric utility's storm response. As a result, storm response requirements are now more formalized, more comprehensive, and more rigorous. See, e.g., G.L. c. 164, § 1J; 220 CMR 19.03 (setting forth standards for the acceptable performance for emergency preparation and restoration services for electric and gas companies); Investigation by Department of Public Utilities into Responses to Tropical Storm Irene and October 2011 Snowstorm, D.P.U. 11-85-B/11-119-B at 141 (2012) (imposing penalties for company's failure to timely respond to emergency wires-down calls and communicate effectively with municipal officials and customers); D.P.U. 11-119-C at 71-72 (imposing penalties for company's failure to restore service to its customers in a safe and reasonably prompt manner). To meet these requirements, EDCs are expected to properly prepare for and implement storm response measures that restore power safely and expeditiously. These obligations require the Company to devote substantial resources to achieving the desired results. Further, as the Company's recent history indicates, the frequency and severity of major storms has increased (see, e.g., Exhs. ES-REVREQ-1, at 159; ES-REVREQ-2, Sch. 22, at 2 (Rev. 4); ES-REVREQ-4, Sch. 11 & Atts.; DPU 4-8, Atts. (b), (c), (d); DPU 20-3, Att.; AG 11-29, Att.; AG 8-80, Att.). Not surprisingly, the costs of responding to these events have increased as well (see, e.g., Exhs. ES-REVREQ-4, Sch. 11 & Atts.; DPU 4-8, Atts. (b), (c), (d); DPU 20-3, Att.; AG 8-80, Att.).

We acknowledge that NSTAR Electric's current storm fund mechanism has not provided the desired balance between cost recovery and rate stability. Specifically, the overall number of NSTAR Electric's major storm events in the past several years have contributed to a large storm fund deficit that expanded even further due to the accumulation of a significant amount in carrying charges.[136] The severity and frequency of these storms could not have been anticipated when NSTAR Electric's storm fund mechanism was developed, or when it was most recently refined in D.P.U. 17-05. As a result, without a storm fund mechanism, it is unlikely that NSTAR Electric could have absorbed the large

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[136] As previously noted, the Company estimates its current storm fund deficit at $106 million (Exh. DPU 4-8, Att. (b)).

accumulation of storms costs over the past several years without filing a base distribution rate case, or even multiple rate cases, which could have resulted in an increase in rates for distribution service other than storm fund costs. Moreover, coupled with the five-year stay-out provision associated with the Department-approved PBR mechanism in the instant proceeding (see Section IV.D.5.a above), a storm fund remains an important cost recovery mechanism.[137]

Therefore, we find that, if properly structured, allowing NSTAR Electric to continue to operate a storm fund can provide for adequate recovery of storm costs in a manner that is designed to create rate stability. On that basis, we conclude that the storm fund shall continue, but with several modifications, as discussed below.

3. Storm Fund Modifications

a. Storm-Fund-Eligible Event Threshold

The Company proposes to increase the storm-fund-eligible event threshold to $1.3 million in incremental O&M costs (Exhs. ES-CAH/DPH-1, at 98; ES-REVREQ-1, at 162). NSTAR Electric states that its proposal is based on increasing the current threshold of $1.2 million by the cumulative inflation change of the GDP-PI, as reported by the U.S. Bureau of Economic Analysis, from 2016 through 2020 (Exhs. ES-REVREQ-1, at 163; DPU 4-7, Att.).

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[137] The Department notes that the PBR mechanism does not apply to the storm-fund-eligible events or thresholds.

The Department has reviewed the Company's storm-fund-eligible event threshold calculation and finds it to be reasonable and consistent with Department precedent. D.P.U. 17-05, at 548-549; D.P.U. 18-150, at 416; D.P.U. 15-155, at 76-77. Further, we find that this increased threshold strikes an appropriate balance between providing NSTAR Electric with necessary access to the storm fund to recover costs associated with major storms and ensuring that the routine storms are not contributing to a storm fund deficit balance. Accordingly, we approve a storm-fund-eligible event threshold of $1.3 million per storm event.

b. Annual Storm Fund Contribution Collected Through Base Distribution Rates

The Company proposes to increase the annual storm fund contribution collected through base distribution rates to $31 million (Exhs. ES-CAH/DPH-1, at 98; ES-REVREQ-1, at 162, 181; ES-REVREQ-2, Sch. 22 (Rev. 4)). A storm fund is intended to provide a level of rate stability for customers, but only if it actually allows for recovery of storm costs over time without requiring a change to customer rates. D.P.U. 17-05, at 551; D.P.U. 15-155, at 78. As evidenced by the increased frequency and magnitude of storm fund eligible storms since 2017, and the projected storm deficit balance of $106 million if the current storm fund contribution and number and magnitude of storms remained the same, the current annual storm fund contribution of $10 million has proven to be insufficient to maintain rate stability (Exhs. ES-REVREQ-1, at 159, 179-181; ES-REVREQ-2, Sch. 22, at 2 (Rev. 4); ES-REVREQ-4, Sch. 11 & Atts.; DPU 4-8, Atts. (b), (c), (d); DPU 20-3, Att.; AG 11-29, Att.; AG 8-80, Att.). Thus, we conclude that an increase in the base distribution rate contribution to the storm fund is warranted. D.P.U. 18-150, at 423; D.P.U. 17-05, at 551; D.P.U. 15-155, at 178; Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 13-85, at 101, 106 (2016); Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 13-59 (2013).

Here, the Department seeks to set a new annual storm fund contribution amount in base distribution rates that will allow the Company to recover storm costs over time without generating a surplus or deficit balance in the storm fund that exceeds the symmetrical cap.[138] We recognize the uncertainty in achieving this result given the unpredictable nature of weather in general, and storm-fund qualifying events in particular. Further, we acknowledge that, while major historical storm events provide some perspective regarding the frequency, severity, and cost of major storms, such information is by no means sufficiently predictive with any degree of certainty to definitively plan for future storm events. Notwithstanding these considerations, however, NSTAR Electric's storm fund history is instructive in the context of developing new and updating existing elements of the storm fund.

The Department has reviewed the record supporting the proposed annual storm fund contribution by NSTAR Electric (see, e.g., Exhs. ES-CAH/DPH-1, at 98; ES-REVREQ-1, at 163-164, 181; ES-REVREQ-2, Sch. 22 (Rev. 4); ES-STORMS-Rebuttal-1, at 16-24; DPU 4-8, at 3). In its review, the Department considered the number of storms that have

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[138] In D.P.U. 17-05, the Company proposed, and the Department allowed, a symmetrical cap of $30 million on the storm fund's balance to trigger either a customer refund for an over-recovery balance that exceeds the cap, or a customer charge for an under-recovery balance that exceeds the cap. D.P.U. 17-05, at 532-533, 554-555.

occurred between the Company's last rate case and the end of the test year; the incremental cost of these storms; the number of storms with incremental O&M costs that were so extraordinarily high that they should be deemed statistical outliers; and the number of storms that would not have been eligible for storm fund recovery had the $1.3 million storm-fund-eligible event been in effect (Exhs. ES-REVREQ-4, Sch. 11 & Atts.; DPU 4-8, Atts. (b), (c), (d); DPU 20-3, Att.; AG 11-29, Att.; AG 8-80, Att.). Additionally, we reviewed the calculation applied by the Company as the basis to establish its proposed $31 million annual storm fund contribution amount and find that it is consistent with the Department precedent (Exhs. ES-REVREQ-1, at 181; ES-REVREQ-2, Sch. 22 (Rev. 4)). D.P.U. 17-05, at 531, 553.

We are not persuaded by the Attorney General's argument that the Company's proposal represents a significant shift of risk to ratepayers. We find that the proposal sufficiently reflects the Company's storm fund history and as noted above, is consistent with Department precedent. Further, we conclude that increasing the annual storm fund contribution is a reasonable and appropriate approach to provide sufficient funds to levelize the rate impact for major storms that are eligible for cost recovery through the storm fund and decrease the likelihood that the storm fund will attain a large deficiency balance. Thus, contrary to the Attorney General's contention, we find that increasing the annual storm fund contribution is necessary to maintain rate stability over the long term. Accordingly, we approve the Company's proposal to increase the annual storm fund contribution collected through base distribution rates to $31 million.

c. Annual O&M Expense for Storm Events

NSTAR Electric proposes to increase the annual O&M expense associated with storm events to $7.8 million (Exh. ES-REVREQ-1, at 164-164). The Company bases this proposal on the average number of storm-fund-eligible events from 2017 through 2020, which were six events on average, multiplied by the proposed storm-fund-eligible event threshold of $1.3 million (Exhs. ES-CAH/DPH-1, at 98; ES-REVREQ-1, at 164-165; AG 12-6).

As the frequency and magnitude of storm events has varied significantly year-to-year, the Department recognizes that the test-year level of O&M costs in base distribution rates is not necessarily representative of the Company's future costs. D.P.U. 17-05, at 550. Therefore, consistent with Department precedent, we find it necessary to normalize the level of base distribution rate recovery to derive a more representative threshold amount for O&M expenses associated with storm events. D.P.U. 18-150, at 418-419; D.P.U. 17-05, at 550; D.P.U. 15-155, at 80-81. The Department finds that the Company's proposed annual O&M expense of $7.8 million in base distribution rates, based upon recovery for six storm-fund-eligible events per year and applying the approved $1.3 million storm-fund-eligible event threshold, is reasonable and consistent with Department precedent. D.P.U. 18-150, at 418-419; D.P.U. 17-05, at 550; D.P.U. 15-155, at 80-81. Accordingly, we approve the Company's proposal.

d. Recovery of Storm-Fund-Eligible Event Threshold After the Seventh Storm Event

NSTAR Electric proposes that, for each storm-fund-eligible event subsequent to the seventh storm event in a calendar year, the Company is permitted to recover the storm-fund-eligible event threshold of $1.3 million through the storm fund (Exhs. ES-CAH/DPH-1, at 98; ES-REVREQ-1, at 162, 165-166, 169-170; DPU 34-1). Conversely, if there are less than five storm-fund-eligible events in a calendar year, customers would receive a $1.3 million credit for the number of events less than five that did not occur (Exhs. ES-CAH/DPH-1, at 98; ES-REVREQ-1, at 162, 169-170; DPU 34-1).

The Department recognizes that the frequency of storm-fund-eligible storms is inherently variable year-to-year and as a result cost recovery may not align with the amounts collected through base distribution rates for a set number of storms. Nonetheless, based on the record evidence, the Department is persuaded that it is more likely than not that the number of storm-fund-eligible storms will increase in future years due to weather patterns and meteorological characteristics associated with climate change (Exhs. ES-STORMS-REBUTTAL-1, at 8; DPU 4-1). See also Inflation Reduction Act of 2022, P.L. 117-169, § 50153 (appropriating funds to address the effects of changes in weather due to climate change on the reliability and resiliency of the electric grid). Therefore, the Department agrees with the Company and finds it reasonable to establish a measure of relief in years when the number of storm-fund-eligible events significantly exceed the representative number in base distribution rates. See D.P.U. 21-75/D.P.U. 21-76, at 22. The Department, however, finds that the Company's proposal to allow it to recover storm-fund-eligible event thresholds for six events in base rates and any event after the seventh event does not appropriately balance the financial risk between the Company and ratepayers. More than one storm event above average does not constitute a significant variation from the average number of annual storms. Based on consideration of the frequency of storms, the Department finds that three storm events after above the average number of storm events is a significant variation in the reasonably anticipated number of storms. Therefore, the Company may recover storm-fund-eligible event thresholds of $1.3 million through the storm fund for each storm-fund-eligible event subsequent to the eighth storm event in a calendar year.

The Company's proposal also seeks to provide relief to ratepayers if there are fewer than five storm-fund-eligible events in a year (Exhs. ES-CAH/DPH-1, at 98; ES-REVREQ-1, at 162, 169-170; DPU 34-1). In conjunction with the above modifications, the Department finds that the Company's proposal appropriately balances the financial risk between NSTAR Electric and ratepayers. Thus, we approve this aspect of the proposal.

Based on the above considerations and findings, we approve the Company's proposal, as modified herein.

4. Other Proposals

a. Recovery of Storm-Fund-Eligible Event Thresholds for 2020 and 2021 Storms

The Company proposes to recover through the storm fund the current storm-fund-eligible threshold of $1.2 million for six storm-fund-eligible events that occurred in 2020 and seven storm-fund-eligible events that occurred in 2021, for a total of $15.6 million in costs (Exh. ES-REVREQ-1, at 173; Company Brief at 328; Company Reply

Brief at 49).[139] As noted, the Commonwealth is experiencing weather patterns and meteorological characteristics associated with climate change. See also D.P.U. 21-75/D.P.U. 21-76, at 27. When the Department established the annual O&M expense in base distribution rates in 2017, we did not anticipate that number of storm events would vary significantly from the representative amount. D.P.U. 21-75/D.P.U. 21-76, at 22. The Attorney General argues that allowance would retroactively alter the entire regulatory treatment of storm costs and storm fund cost eligibility (Attorney General Brief at 135-136). We disagree. The costs that the Company proposes to collect do not retroactively change rates provided for prior service. D.P.U. 10-70, at 216. Instead, the increased costs are due to changes in weather patterns and increased storm activity since the Company's last base distribution rate case (Exhs. ES-STORMS-REBUTTAL-1, at 8; DPU 4-1). Based on the changes that have occurred since 2017, we find it appropriate to allow the Company to recover the threshold amounts for storm-fund-eligible events that significantly exceeded the representative level in 2020 and 2021. The Department, however, finds that a deviation greater than one storm is not a significant deviation from the representative level of storms contemplated in D.P.U. 17-05. Consistent with our above

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[139] In D.P.U. 21-75/D.P.U. 21-76, at 28, the Department allowed NSTAR Electric to apply deferred accounting treatment to the excess calendar year 2020 storm-fund-eligible event threshold amounts (i.e., the threshold amounts that exceed those already recovered in base rates less one) until the Company's next base rate proceeding. There was no specific deferral of the storm-fund-eligible event thresholds for the seven storm events that occurred in 2021, which the Company seeks to include in this proposal.

findings, the Department finds that a deviation of three or more storms above the representative level constitutes a significant variation that was not anticipated in the approval of the storm fund mechanism. Accordingly, the Company may recover the current storm-fund-eligible threshold of $1.2 million for five storm-fund-eligible events that occurred in 2020 and six storm-fund-eligible events that occurred in 2021, for a total of $13.2 million in costs.

b. Maintaining the Current SCRAF

NSTAR Electric proposes to maintain its current SCRAF for effect on January 1, 2023, subject to a future prudence review and reconciliation of the storm costs, to recover a portion of the Company's outstanding storm fund deficiency of approximately $106 million over a five-year period for an annual amortization amount of $21.2 million (Exhs. ES-REVREQ-1, at 178-180; DPU 4-8, Att. (b)).[140] Currently, the Company recovers an annual amortization amount of $28 million through the SCRAF for costs associated with storm-fund-eligible events that occurred prior to February 1, 2018 (Exh. ES-REVREQ-1, at 178). On December 31, 2022, the amortization period associated with these storms expires (Exhs. ES-REVREQ-1, at 178; DPU 4-14). The Company anticipates additional storm activity to occur in 2022 that would further increase the storm fund deficit

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[140] In its review of NSTAR Electric's 2020 SCRAF filing, the Department determined that it would review the appropriate method for cost recovery of the storm fund deficiency balance in the instant base distribution rate case. D.P.U. 20-29, Interlocutory Order on Motion for Adoption of Storm Cost Review Schedule at 9-10 (December 21, 2021).

(Exh. ES-REVREQ-1, at 179). If the Company were to reflect the current storm fund deficit amortized over five years in rates effective January 1, 2023, it estimates relatively small bill impacts (0.1 percent decrease for EMA customers and 0.6 percent increase for WMA customers) (Exh. ES-REVREQ-1, at 179). We find the Company's proposal is a reasonable and appropriate way of recovering the outstanding storm fund deficiency, subject to required prudence reviews and reconciliation, while maintaining rate stability and mitigating carrying charges. Accordingly, we allow this proposal.

c. Recovery of Storm Costs for Tropical Storm Henri and the October 2021 Nor'easter

The Company proposes to recover through the SCRAF beginning on January 1, 2024, subject to future prudence review and reconciliation, $196.2 million in exogenous costs associated with Tropical Storm Henri and the October 2021 Nor'easter (Exhs. ES-REVREQ-1, at 179-180; ES-REVREQ-4, Sch. 11(d); DPU 4-8, Att. (c); DPU 4-13). The Company proposes to recover the costs for these two storm events over a five-year period for annual amortization amount of $39.2 million (Exhs. DPU 4-8, Att. (c), at 1; DPU 4-13; DPU 4-14 & Att.). The amortization of the exogenous costs currently collected through the SCRAF expires on December 31, 2023 (Exhs. ES-REVREQ-1, at 179; DPU 4-13, at 1).

We recognize the Attorney General's concern that the Company has not yet provided supporting documentation for Department review (Attorney General Brief at 139). Nonetheless, the Department has previously allowed a company to begin recovering storm-related costs before the company has submitted finalized invoices, subject to investigation and reconciliation. See, e.g., D.P.U. 18-101, at 23-24 (allowing NSTAR Electric to begin recovery of three exogenous storms in advance of finalized costs); D.P.U. 13-59, at 1-2, 14 (allowing National Grid to replenish its storm fund subject to prudence review and reconciliation of costs associated with 14 storms); D.P.U. 09-39, at 210-212 (allowing National Grid to begin recovering 2008 winter storm costs subject to investigation and reconciliation).

We find that it is reasonable and appropriate to allow NSTAR Electric to begin cost recovery of these storm events through the SCRAF beginning on January 1, 2024, as it strikes an appropriate balance between cost recovery and rate stability. Allowing the proposal will avoid significant fluctuations in customer rates and mitigate carrying charges to customers (Exh. DPU 4-13). If the Department finds any of the costs associated with these two storm events to be imprudent, the Company must return the costs to customers with interest at the prime rate calculated from the time the costs were incurred. Thus, customers will not be harmed by the commencing of cost recovery for these two storm events beginning on January 1, 2024. Accordingly, we allow this proposal, subject to the findings herein.

d. Other Storm Fund Components

The Company does not propose any changes to the storm fund cap, carrying charges related to storm-fund-eligible and exogenous storm events, or reporting on storm events. The Department finds that these components of the storm fund shall continue consistent with the directives set forth in D.P.U. 17-05 and any subsequent Department decisions.

E. Conclusion

Based on the above findings, the Department directs NSTAR Electric to implement its storm fund with the modifications set forth herein. The modified storm fund shall apply to any storm-fund-eligible events that occur on or after January 1, 2023. The Company's outstanding storm fund balance shall be recovered consistent with the findings above. The recovery of storm-related costs for Tropical Storm Henri and the October 2021 Nor'easter will commence on January 1, 2024, as described above.

Further, the Company may recover \$13.2 million through the storm fund effective January 1, 2023, which represents the current storm-fund-eligible event threshold of \$1.2 million for five storm-fund-eligible events that occurred in 2020 and six storm-fund-eligible events that occurred in 2021, as discussed above. Finally, as part of its compliance filing in this proceeding, the Company shall file a revised storm cost recovery adjustment tariff consistent with the storm-related directives set forth above.

XI. VEGETATION MANAGEMENT PROGRAM

A. Introduction

The Company's current Vegetation Management Program consists of two components, the Base Vegetation Management Program ("Base VM Program") and the Resiliency Tree Work Program ("RTW Program").[141] As outlined below, the Company has proposed several

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[141] For a complete background on the Company's Vegetation Management Program see D.P.U. 17-05, at 563-591; D.P.U. 11-85-B/11-119-B; and D.T.E. 06-55.

changes to these two components and also has proposed a municipality specific hazard tree removal pilot program.

B. Base Vegetation Management Program

1. Introduction

NSTAR Electric's Base VM Program involves the management of trees along distribution lines and at substation facilities to provide a safe work environment for line workers, to allow visual and physical access to the Company's electric facilities, to prevent damage to electric equipment, and to improve reliability, shorten restoration times, and improve customer satisfaction (Exh. ES-WAV-2, at 2). The Company's service area includes two distinct geographic areas, i.e., EMA and WMA, that differ to a certain extent due to varying weather patterns, landscapes, and tree species (Exh. ES-WAV-1, at 6-7). As such, the Company does not perform the same type of work in the two geographic areas (Exh. ES-WAV-1, at 6-7).

2. Company Proposal

The Company's current Base VM Program includes an established trim cycle to ensure that all circuits, regardless of performance, are trimmed at least once every four to five years, subject to circuit-specific considerations (Exhs. ES-WAV-1, at 3; DPU 39-10, at 4). Due to the differences in the two geographic areas, the Company proposes to eliminate the requirement for a blanket four- to five-year trim cycle and, instead, prioritize circuits based on performance and reliability (Exhs. ES-WAV-1, at 14-15; DPU 39-10, at 4-6). The Company notes that information systems have evolved, and it is now able to utilize a database of tree-related outages and analysis of SAIDI/SAIFI to prioritize vegetation management resources to be used for at-risk circuits (Exh. ES-WAV-1, at 15-18).[142] NSTAR Electric also proposes to conduct pre-trim mobile visual inspections on every transmission and distribution line at least every four years to ensure that no areas of the distribution system are left unattended and, should it encounter vegetation issues, the Company would address them immediately after inspection (Exh. ES-WAV-1, at 15-16, 19). Under the Company's proposal, all circuits would be trimmed at least every eight years, regardless of inspection or reliability data (Exhs. ES-WAV-1, at 16; DPU 39-10).

The Company proposes to recover $20,007,619 through base distribution rates (Exhs. ES-REVREQ-1, at 104; ES-REVREQ-2, Sch. 21; AG 10-23). The Company based this amount on its test-year Base VM Program expenses (Exhs. ES-REVREQ-1, at 104; ES-REVREQ-2, Sch. 21; AG 10-23).

3. Positions of the Parties

The Company contends that its proposed modification will assist the Company in addressing increasing frequency of weather events caused by climate change by enhancing reliability on the system based on frequency of impact, severity, and customers served (Company Brief at 334-335). The Company asserts that not all distribution lines and circuits are created equal, as each serve different purposes and encounter unique reliability and

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[142] The Company uses a Power BI database to track outages on its system, to isolate and identify specific outage information as it relates to tree impacts on a circuit, and to track the number of customers impacted (Exh. ES-WAV-1, at 16; Tr. 6, at 586-589).

vulnerability issues based on the number of customers and areas served as well as the rate and severity of weather events (Company Brief at 339, citing Exhs. ES-WAV-1, at 15; ES-WAV-Rebuttal-1, at 4-6). NSTAR Electric contends that the proposed reliability-based circuit prioritization would be based on data that was not previously available, as the Company's information systems have evolved so that data as it relates to tree impacts, the number of customers impacted, and specific areas of circuits down to the street, pole, and device location are now tracked and recorded (Company Brief at 339-340, citing Exhs. ES-WAV-1, at 18; ES-WAV-Rebuttal-1, at 5-6; DPU 39-10).

In addition, the Company asserts that due to varying vegetation, some circuits in its service area have existing clearances that do not require trimming every four years, while other circuits have clearances that would benefit from more frequent trimming (Company Brief at 342, citing Exh. DPU 28-6). NSTAR Electric maintains that allowing it to trim some circuits more than once in the four-year cycle and delay other circuits until trimming is necessary, although no trim cycle would exceed eight years, would improve reliability on the system and allocate resources to ensure efficiency and cost containment (Company Brief at 342, citing Exhs. ES-WAV-1, at 5; DPU 39-10). No intervenor addressed the Company's Base VM Program proposals on brief.

4. Analysis and Findings

The Company proposes to utilize a reliability-based analysis to prioritize the circuit trim schedule but to have flexibility to do some circuits more than once in the four- to five-year trim cycle and to schedule some circuits for trim after five years, but no later than eight years (Exh. DPU 39-10, at 5). Based on the record evidence, the Department determines that using a reliability-based analysis will benefit ratepayers by improving the reliability and resiliency of the Company's distribution system (Exhs. ES-WAV-1, at 15, 17; DPU 28-6; DPU 28-9; AG 10-19, at 1-2). We recognize that technology has evolved and that the Company is now better positioned to use different data to prioritize vegetation management resources (Exhs. ES-WAV-1, at 18; ES-WAV-Rebuttal-1, at 5-6; DPU 39-10). Further, the Company has demonstrated that trees and vegetation are the leading cause of customer outages (Exhs. ES-WAV-1, at 6-7, 14, 34; ES-WAV-Rebuttal, at 22). Thus, the Company's proposed modification to focus on reliability-based prioritization inspections is likely to put NSTAR Electric in a better position to meet the Department's SQ guidelines. Revised Service Quality Guidelines, D.P.U. 12-120-D, at 7-8 (2015).

Nonetheless, the Department finds that deferring trimming for eight years may not further the objectives required for a vegetation management program. Specifically, companies are required to meet circuit performance reliability requirements that become more stringent over time. D.P.U. 12-120-D at 7-9. While the Department recognizes that some flexibility in trimming is needed, we find it appropriate to require that any trimming be deferred for no more than five years.[143]

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[143] As discussed in Section IV.D.5.a above, the Department has approved a PBR plan for NSTAR Electric with a five-year term, with the potential to continue the term for another five years. At the time of its next base distribution rate case filing, or request to continue the PBR term, the Company shall submit to the Department an updated reliability-based analysis, which shall include outage impacts of the tree trimming,

Finally, it is a well-established Department precedent that base distribution rate filings are based on an historic test year, adjusted for known and measurable changes. D.P.U. 10-70, at 232, 254-255; Eastern Edison Company, D.P.U. 1580, at 13-17, 19 (1984); Massachusetts Electric Company, D.P.U. 136, at 3-5 (1980). Here, the Company's test-year expenditure was $20,007,619 (Exhs. ES-REVREQ-2, Sch. 21, at 2; AG 10-23). Based on the record evidence, we find that the test-year expenditure is representative of the Company's spending for its Base VM Program vegetation management (Exhs. ES-REVREQ-1, at 104; ES-REVREQ-2, Sch. 21; AG 10-23). Therefore, we allow the inclusion of $20,007,619 in base distribution rates.

C. Resiliency Tree Work Program

1. Introduction

The Company's RTW Program was established as a six-year pilot program, from January 1, 2017 through December 31, 2022. D.P.U. 17-05, at 580-581.[144] The RTW Program costs are recovered on an annual basis through a reconciling mechanism, i.e., the RTW factor.[145] D.P.U. 17-05, at 583-584. The Company proposes to continue operation of the RTW Program but modify cost recovery (Exh. ES-WAV-1, at 37). Specifically, NSTAR

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visual comparisons of areas trimmed frequently and less frequently to demonstrate the accuracy of the analysis, and data-based improvements to the program.

[144] For additional background on the RTW Program, refer to D.P.U. 17-05, at 563-584.

[145] Pursuant to the RTW Program tariff, the Company submits an RTW factor filing annually on September 15th for rates effective January 1st (Exhs. ES-WAV-1, at 23; ES-WAV-3, at 18; ES-RDC-6, Sch. 2, at 338, 342).

Electric proposes to collect RTW Program costs from January 1, 2017 to December 31, 2022, through the RTW factor (Exh. ES-WAV-1, at 37).[146] For work performed after January 1, 2023, the Company proposes to transfer a representative level of costs into base distribution rates (Exh. ES-WAV-1, at 32, 37). Specifically, the Company's proposes to include $23.2 million in base distribution rates, which is comprised of: (1) $3.2 million for mid-cycle trimming; (2) $5.0 million for maintenance enhanced tree trimming and RTW trimming; and (3) $15.0 million for tree removals (Exhs. ES-WAV-1, at 34-35; ES-WAV-3, at 16).[147]

2. RTW Program Overview

The Company's RTW Program consists of three main components. First, the RTW Program trimming specification is applied to circuits that are considered at risk for reliability and is different from both the scheduled maintenance trim specification and the maintenance

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[146] The RTW Program costs for 2017 through 2021 are under investigation in separate dockets. NSTAR Electric Company, D.P.U. 21-108; NSTAR Electric Company, D.P.U. 20-97; NSTAR Electric Company, D.P.U. 19-114; NSTAR Electric Company, D.P.U. 18-102. The Company proposed that the Department review such costs and issue final approval of the costs in this proceeding (Exh. ES-WAV-1, at 37-38). The Department has already determined that it would not adjudicate the RTW Program costs for 2017 through 2021 in this proceeding, and we need not revisit that decision. D.P.U. 22-22, Interlocutory Order on Scope of Proceeding at 10 (March 9, 2022) ("Scoping Order"). On September 23, 2022, the Company filed its annual RTW factor for 2022. NSTAR Electric Company, D.P.U. 22-123. Therefore, 2022 RTW Program costs were not discussed on brief or in the Scoping Order.

[147] To facilitate the Department's review in the Company's next base distribution rate case, NSTAR Electric proposes to continue tracking the RTW Program activities and costs separately from the Base VM Program (Exh. ES-WAV-1, at 35-36).

enhanced tree trimming specification (Exhs. ES-WAV-1, at 23; ES-WAV-3, at 13). The Company's experience is that the majority of tree-related outages occur from limbs and trees that are located beyond the maintained Base VM Program trim zone (Exh. ES-WAV-1, at 23). The RTW Program trimming specification expands the Base VM Program trim zone on the backbones of critical circuits to 15 feet to the side of the circuit and 25 feet above the circuit (Exhs. ES-WAV-1, at 23; ES-WAV-3, at 13; DPU 39-10). The Company states that this enhanced trim zone helps to make circuits more resilient to tree-caused outages (Exhs. ES-WAV-1, at 23; ES-WAV-3, at 13).

Second, the RTW Program is intended to complement the Company's Base VM Program's existing tree removal activities by expanding the identification and removal of hazard and at-risk trees beyond each circuit's backbone to include laterals serving 100 or more customers as well as off-road rights-of-way located on private property (Exhs. ES-WAV-3, at 14; ES-WAV-1, at 24; DPU 39-10). This expansion of tree removal is intended to support a reduction in the number of customers impacted by fallen trees (Exh. ES-WAV-1, at 24).

Third, mid-cycle trimming[148] is an element in the Company's strategy to address emerging poor-performing circuits (Exhs. ES-WAV-1, at 24; DPU 39-10). The Company

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[148] As outlined in Section XI.B.2 above, the Company currently follows an established trim cycle to ensure that all circuits are trimmed at least once every four to five years (Exh. ES-WAV-1, at 3). Mid-cycle (or off-cycle) trimming is trimming that occurs earlier than the established trim cycle and is taken on a proactive basis to address poor-performing circuits and other anomalies (Exh. ES-WAV-1, at 3).

stated that mid-cycle trimming provides the flexibility to address immediate issues on circuits that are not scheduled for trimming under the Base VM Program (Exh. DPU 39-10). The Company states that mid-cycle trimming is also consistent with the Department's reliability directive to trim all circuits at least once every five years (Exhs. ES-WAV-1, at 24; ES-WAV-3, at 14, citing D.P.U. 11-85-B/11-119-B at 135).

3. Positions of the Parties

a. Attorney General

The Attorney General asserts that the Department should reject the Company's request to continue the RTW Program (Attorney General Brief at 141). The Attorney General maintains that the RTW Program was not approved to extend beyond six years (Attorney General Brief at 139). Moreover, the Attorney General asserts that the RTW Program, which has been in effect for five of the six planned years, should have already accomplished most of its intended goals to improve reliability and expand the clearance specifications for circuits classified as at risk (Attorney General Brief at 140, citing NSTAR Electric Company, D.P.U. 21-108, Exh. ES-WAV/RWF-1, at 12).

In addition, the Attorney General asserts that felled trees removed through the RTW Program will not re-emerge as vegetation management issues (Attorney General Brief at 10). Further, the Attorney General maintains that while vegetation will continue to grow, it should be manageable through the Company's Base VM Program on an approved trim cycle (Attorney General Brief at 140). In addition, the Attorney General contends that continuation of the RTW Program creates redundancy of vegetation services (Attorney General Brief at 140-141). Specifically, the Attorney General asserts that an augmented vegetation management plan, such as the RTW Program, targets the Company's entire distribution system resulting in multiple crews targeting the same circuits (albeit with different trim specifications) and yielding operational redundancies and unwarranted vegetation management costs (Attorney General Brief at 140-141).

Finally, the Attorney General recommends that the Department reject the Company's proposal to transfer $23.2 million of RTW Program costs to base distribution rates (Attorney General Brief at 141, citing Exh. ES-WAV-1, at 3, 34-35). The Attorney General notes that the Department approved the recovery of RTW Program costs for 2017 through 2021 subject to further investigation and reconciliation, and that such further investigation has not yet concluded (Attorney General Brief at 141-142, citing D.P.U. 21-108, at 4; NSTAR Electric Company, D.P.U. 20-97, at 4; NSTAR Electric Company, D.P.U. 19-114, at 4; NSTAR Electric Company, D.P.U. 18-102, at 4).

b. Company

The Company asserts that the costs and benefits of its RTW Program are well-established and that it has become an integral part of the Company's overall Vegetation Management Program (Company Brief at 356). The Company highlights four key areas of system improvement arising from the RTW Program, based on a comparison of a three-year average baseline to data from the six-month period from January 2021 to June 2021 (Company Brief at 353-355). The Company asserts that the first area of improvement is customers affected by tree-related outages (Company Brief at 354). Specifically, NSTAR

Electric maintains that the total number of customers affected by tree-related outages declined by 28 percent (Company Brief at 353-354, citing Exh. ES-WAV-1, at 30). Similarly, the Company contends that RTW Program circuits had a 54-percent reduction in tree-related outages as compared to a 17-percent reduction for the non-RTW Program circuits (Company Brief at 354, citing Exh. ES-WAV-1, at 30).

NSTAR Electric contends that the second area of improvement is contributions to SAIDI by tree-related outages (Company Brief at 354). Specifically, the Company asserts that SAIDI tree-related outages on RTW Program circuits decreased by 65 percent as compared to a 32-percent decrease in SAIDI tree-related outages on non-RTW Program circuits (Company Brief at 354, citing Exh. ES-WAV-1, at 30).

The Company claims that the third area of improvement is contributions to SAIFI by tree-related outages (Company Brief at 354). NSTAR Electric asserts that SAIFI associated with tree-related outages on RTW Program circuits decreased 56 percent as compared to an 18-percent reduction in SAIFI tree-related outages on non-RTW Program circuits (Company Brief at 354, citing Exh. ES-WAV-1, at 30-31).

The Company contends that the fourth improvement is a reduction in the number of outages on RTW Program circuits as compared to non-RTW Program circuits (Company Brief at 354). The Company maintains that the RTW Program circuits experience a 40-percent reduction, while the non-RTW Program circuits experienced a nine-percent increase (Company Brief at 354-355, citing Exh. ES-WAV-1, at 31). NSTAR Electric asserts that, based on these results, the RTW Program provides numerous benefits to its overall distribution system by minimizing tree-related outages and improving the customer experience (Company Brief at 355).

In addition, the Company asserts that the RTW Program has yielded benefits of noticeably fewer customer interruptions, a more stable resource of crew availability, and assurance that NSTAR Electric's ongoing grid modernization efforts are not hampered by hazard trees (Company Brief at 355-356, citing Exh. ES-WAV-1, at 31-32). The Company also argues that there is a critical need to continue the RTW Program due to the increasing frequency and severity of weather-related events in NSTAR Electric's service territory (Company Brief at 356). Further, the Company maintains that while trees felled through the RTW Program may not re-emerge as vegetation management issues in the immediate future, other hazard and risk trees will appear, e.g., due to drought, insect infestation, tree species (Company Brief at 363-364).

Further, the Company maintains that contrary to the Attorney General's assertion, the RTW Program is not redundant to the Base VM Program and the reliability benefits may not continue in the absence of the RTW Program (Company Brief at 361, 364, citing Exhs. ES-WAV-1, at 23-24; ES-WAV-Rebuttal-1, at 14-18; DPU 39-10). The Company highlights the circuit trimming specifications and notes that they are distinct from those in the Base VM Program in terms of required clearance (Company Brief at 364, citing Exhs. ES-WAV-1, at 23-24; ES-Rebuttal-1, at 17; DPU 39-10; DPU 66-4).

With respect to its proposal to transfer the RTW Program costs to base distribution rates, the Company asserts that the costs of the RTW Program are stable and therefore representative of future costs (Company Brief at 358, citing Exhs. ES-WAV-1, at 32; DPU 39-10). The Company maintains that it was authorized to recover $23.2 million annual incremental RTW Program O&M expenses and that it has utilized this amount to accomplish the goals of the RTW Program (Company Brief at 358, citing Exhs. ES-WAV-3; DPU 39-10). In addition, the Company maintains that continuing recovery of the RTW Program costs through the annual reconciling mechanism adds an administrative burden to Company personnel as employees assigned to work on the RTW Program are also required to conduct that program's administrative review (Company Brief at 366, citing Exhs. ES-WAV-1, at 32-33; ES-WAV-Rebuttal-1, at 18; AG 10-21).

4. Analysis and Findings

a. Continuation of RTW Program

The Department has recognized the significant financial burden that ratepayers have borne due to high storm restoration costs. The Department has further recognized that a company's poor pre-storm preparation may have adverse effects on that company's ratepayers. D.P.U. 13-90, at 19; D.P.U. 11-01/D.P.U. 11-02, at 70-71; D.P.U. 09-39, at 210-211. Thus, the Department views storm resiliency programs, such as the RTW Program, as a potentially worthwhile step towards strengthening a utility's distribution system and mitigating a portion of the physical damage and financial impacts of future storm events, and thereby benefitting ratepayers. D.P.U. 13-90, at 19. It is for these reasons that the Department allowed the RTW Program on a pilot basis. D.P.U. 17-05, at 580-581.

The Department concludes that the Company has demonstrated that the RTW Program, in conjunction with the Base VM Program, has been beneficial to further reducing storm-related outages through resiliency tree work outside of the Base VM Program trim zone (Exhs. ES-WAV-1, at 30-31; DPU 39-10). Further, there are differences between the Base VM Program and the RTW Program that highlight the uniqueness of each program (Exhs. ES-WAV-1, at 23-24; ES-WAV-Rebuttal-1, at 14). For example, the specific trim zones differ for the Base VM program and the RTW Program (Exh. ES-WAV-1, at 23-24). Further, the RTW Program offers elements of tree work not considered standard practice under the Base VM Program (e.g., enhanced mid-cycle trimming, expanded hazard and risk-tree identification and removal) (Exh. ES-WAV-1, at 24).

In addition, while trees removed through the RTW Program may not reemerge as vegetation management issues in the immediate future, it is apparent that other trees will experience damaging conditions necessitating their removal through the RTW Program (Exh. ES-WAV-Rebuttal-1, at 14-15). In this regard, there are typically multiple hazard tree profile lists for different circuits, which are prioritized by circuit reliability, general condition of the hazard trees, availability of equipment needed depending on the type and size of the tree, and cost implications (Exhs. ES-WAV-1, at 24-25; ES-WAV-Rebuttal-1, at 12). Therefore, we find that continuation of the RTW Program is appropriate to achieve increased reliability (Exhs. ES-WAV-Rebuttal-1, at 14-16; DPU 66-18). For these reasons, the Department allows the RTW Program to continue through the PBR term.

b. RTW Program Cost Recovery

The Company proposes to collect \$23.2 million annually through base rates for RTW Program expenses (Exhs. REV-REQ-1, at 104; ES-REVREQ-2, Sch. 21, at 2; ES-WAV-3, at 16). The investigation of the RTW Program costs for 2017 through 2021 is ongoing in separate dockets. D.P.U. 21-108; D.P.U. 20-97; D.P.U. 19-114; D.P.U. 18-102. Thus, the RTW Program costs are neither known nor measurable. Therefore, the Company is unable to establish an appropriate level of costs to include in base distribution rates. We also note that there has been some volatility in the costs, with costs in only calendar year 2021 exceeding the proposed \$23.2 million (Exh. AG 10-22).[149]

Based on these factors, the Department disallows the Company's request to move the RTW Program costs into base distribution rates. Instead, any costs incurred for the RTW Program from January 1, 2023, will continue to be collected through the RTW factor. The Company is directed to continue submitting annual filings demonstrating its RTW Program costs.[150] Therefore, the Department will remove \$23.2 million from the Company's proposed cost of service (Exh. ES-REVREQ-2, Sch. 21, at 2 (Rev. 4); Department

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[149] The Company reports incurring the following annual RTW Program costs: \$2,875,000 in 2017, \$20,629,368 in 2018, \$19,296,574 in 2019, \$21,249,610 in 2020, and \$23,404,894 in 2021 (Exh. AG 10-22).

[150] Pursuant to the RTW Program tariff, the Company submits an RTW factor filing annually on September 15th for rates effective January 1st (Exhs. ES-WAV-1, at 23; ES-WAV-3, at 18; ES-RDC-6, Sch. 2, at 338, 342). The RTW Program tariff will remain in effect, and the Company is directed to continue submitting its annual RTW factor filings pursuant to this schedule.

Schedules 2, 9 below). The Company shall file a revised RTW Program tariff consistent with these findings.

c. Future Filing Requirements

The Department has directed NSTAR Electric to track and maintain necessary information related to its RTW Program, including, but not limited to, costs, benefits, and contribution to reliability improvements (Exh. ES-RDC-6, Sch. 2, at 342). D.P.U. 17-05 at 581-582. Given that the Department is allowing the RTW Program to continue, we find it appropriate to require certain documentation to be submitted in the Company's annual filings. Specifically, the Company's annual filings shall include information about circuits and circuit segments (i.e., circuit identifier, circuit type, circuit voltage, three-phase miles, two-phase miles, single-phase miles, total circuit miles, municipality name(s)), program work and activity by circuit and circuit segments[151] and cost information (i.e., tree removal costs, trimming costs, other costs if applicable, tree contractors, trimming contractors, contractors for other work performed).

Further, all invoices submitted by the Company shall provide detailed work descriptions and locations and should be clearly attributable to the RTW Program, i.e., differentiated from work done pursuant to the Base VM Program. In addition, the

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[151] For tree work, the Company should provide whether a profile was conducted, the primary reason(s) for initiating work, work performed, trees removed, tree contractor, tree removal cost, and cost per tree removal. For trimming work, the Company should provide circuit miles planned for trimming, primary reason for initiating work, work performed, actual circuit miles trimmed, percent of planned work complete, total pruning cost, and cost per mile for trimming.

Company's annual filing shall include separate spreadsheets detailing: (1) future year planned work by circuit, including circuit priority; (2) a report on revisions of the previously planned work for the current year, i.e., reprioritization based on circuit and SQ data; (3) data on circuit improvements (customers affected, outage events, improved restoration times, etc.) as a three-year average, current year, and variance; (4) service-quality data information by system and circuit as a three-year average, current year, and variance; and (5) worst-performing three-phase circuits (i.e., bottom 25 percent of circuits, including circuit average interruption duration index ("CKAIDI"), circuit average interruption frequency index ("CKAIFI"), and circuit interruption, reported as a three-year average, current year, and variance).

D. Municipal Hazard Tree Removal Pilot Program

1. Introduction

The Company proposes a new pilot program, the municipal hazard tree removal pilot program, to begin January 2023 (Exhs. ES-WAV-1, at 4, 20; ES-RDC-6, Sch. 1, at 527; DPU 28-19). NSTAR Electric states that the current process to remove hazard trees near the distribution system takes significant time because the Company is required to obtain the requisite municipal permissions, which is a costly process when done on a state-wide basis (Exhs. ES-WAV-1, at 20; DPU 28-10). For its proposed pilot program, the Company states it would partner with municipalities to conduct surveys, identify multiple hazard tree removals, develop municipality-specific removal plans, and expedite the commissioning and approval process on a much larger scale (Exhs. ES-WAV-1, at 20-21; DPU 39-10, at 6).

The Company states its arborists would work directly with municipal tree wardens to identify hazard trees and jointly finalize a removal list (Exh. DPU 57-12).

The Company proposes to rank municipalities based on: (1) those municipalities that are willing to work with the Company to achieve more removals; and (2) those municipalities having a SAIDI/SAIFI reliability measure that is one of the 40 worst in Massachusetts (Exhs. DPU 28-10; DPU 57-12, Att.). The Company would then submit the municipal plans to the Department with cost-benefit analyses for informational purposes so that the Department is aware of the municipalities involved (Exh. ES-WAV-1, at 21).

The Company estimates an annual total cost of $1 million for the proposed pilot program (Exhs. ES-WAV-1, at 21; AG 10-17). The Company estimates an average tree removal cost of $1,000, and states that the $1 million budget would allow it to remove 50 hazard trees in 20 municipalities each year, at a cost of $50,000 per municipality (Exhs. ES-WAV-1, at 21; AG 10-17). The Company proposes to recover the costs of the proposed pilot program through the RTW factor rather than base distribution rates because the costs will be variable and unpredictable until the program matures (Exhs. ES-WAV-1, at 4, 22; ES-RDC-6, Sch. 2, at 341). The Company proposes to provide actual costs with supporting invoices for recovery through the RTW factor (Exhs. ES-WAV-1, at 22; DPU 28-20 & Att. at 3; AG 10-17).

2. Positions of the Parties

a. Attorney General

The Attorney General asserts that the Company failed to provide sufficient details regarding the proposed municipal hazard tree removal pilot program (Attorney General Brief at 142-143). In particular, the Attorney General maintains that the Company failed to provide annual pilot program costs (Attorney General Brief at 143). The Attorney General also argues that the removal of hazardous trees is already part of the RTW Program and that the Company failed to explain why this pilot program is not redundant (Attorney General Brief at 142-143). In addition, the Attorney General questions why a partnership with municipal tree wardens and municipal officials has not already been forged through the Company's Vegetation Management Program (Attorney General Brief at 143). Finally, the Attorney General contends that the Company has claimed that the pilot would reduce the amount of money needed for removal of certain hazard and risk trees, but that NSTAR Electric has not reflected such a reduction in its request to move RTW Program costs into base distribution rates (Attorney General Brief at 143, citing Exh. AG 10-16, at 1; Tr. 6, at 549).

b. Company

The Company asserts that it is requesting $1 million for this pilot program because that proposed annual budget would allow it to work with up to 20 individual municipalities annually to develop a town-specific plan to remove up to 50 hazard trees (as opposed to up to three trees over 20 years) (Company Brief at 368, citing Exhs. ES-WAV-1, at 21-22;

ES-WAV-Rebuttal-1, at 22; AG 10-17). The Company maintains that it cannot provide a more precise estimate of the costs because municipality participation is out of the Company's control, and for that reason, it proposes to report to the Department more precise costs and estimates with a cost-benefit analysis once the municipal hazard tree removal pilot program is underway (Company Brief at 368, citing Exhs. ES-WAV-1, at 21; DPU 28-8; DPU 39-10; DPU 39-14; AG 10-16).

In addition, the Company contends that the proposed pilot program is not redundant with its Base VM Program or the RTW Program because under those programs, the Company does not have the budget to accommodate broad municipal-specific plans and only removes one or two trees at a time in any given municipality, over many years (Company Brief at 369, citing Exhs. ES-WAV-1, at 20; ES-WAV-Rebuttal-1, at 22; DPU 28-8). Further, the Company argues that the proposed pilot program will result in hazard tree removals that are in addition to the trees that will be removed under the existing RTW Program (Company Brief at 369, citing Exhs. ES-WAV-Rebuttal-1, at 22; DPU 28-10).

Finally, the Company asserts it has established relationships with municipal tree wardens and municipal officials and that these relationships are stable and constantly developing (Company Brief at 369-370, citing Exhs. ES-WAV-1, at 20; ES-WAV-Rebuttal-1, at 22; DPU 28-8). The Company argues that the issue is not the relationship, but rather that the Company does not have the resources to assign crews to specific municipalities to focus on hazard tree removal (Company Brief at 370, citing Exhs. ES-WAV-1, at 20; ES-WAV-Rebuttal-1, at 22; DPU 28-8). The Company asserts that a larger-scale municipal hazard tree removal program would have a significant impact on reliability and resiliency and reduce storm damage and costs (Company Brief at 370, citing Exhs. ES-WAV-Rebuttal-1, at 23; DPU 28-8).

3. Analysis and Findings

While we acknowledge the importance of NSTAR Electric's goal of reliability and resiliency for its customers, we have several concerns with the pilot program as proposed. For example, the Company is already obligated to work with municipal officials and municipal tree wardens to remove hazard trees on public property. G.L. c. 87, § 14; D.P.U. 11-85-B/11-119-B at 122, 134; Investigation of Emergency Plans for Hurricane Bob, D.P.U. 91-228, at 12 (1992). General Laws c. 87, § 14, outlines requirements and timeframes for companies' coordination with municipal officials and municipal tree wardens. The Department has also directed companies to conduct annual meetings with local tree wardens in each municipality within their service areas. D.P.U. 11-85-B/11-119-B at 122, 134; D.P.U. 91-228, at 12.

In addition, the Department has approved continuation of the RTW Program (see Section XI.C.4.a above). The RTW Program and the Base VM Program both encompass resiliency tree removal activity, which uses the same criteria as the proposed municipal hazard tree pilot program (Exhs. ES-WAV-3, at 12; AG 10-16). Specifically, all three programs identify hazard trees to be removed by focusing on trees causing a pattern of interruptions (Exhs. ES-WAV-1, at 20-21, 25-26, 28; ES-WAV-3, at 12, 14; DPU 39-10, at 6; AG 10-16, at 1). The Company distinguishes the proposed pilot program from the

RTW Program by noting that the RTW Program is typically used to remove a single tree in a municipality (Exh. DPU 28-10). While the Company states it lacks the resources to accommodate municipal-specific plans, there is nothing in the RTW Program that prevents NSTAR Electric from focusing on specific municipalities where there are demonstrated reliability issues to harden the distribution system (Exh. ES-WAV-3, at 13-15). Further, an objective of the RTW Program is to conduct tree trimming and remove hazardous or at-risk trees, so working with municipalities focused in specific geographical areas with reliability issues in parallel with the standard Base VM Program could achieve the objects of the programs and minimize costs (Exh. ES-WAV-3, at 14, 16).

Further, NSTAR Electric acknowledged that it was unable to provide a concrete cost estimate and that it has not yet developed a budget (Exhs. ES-WAV-1, at 22; DPU 28-19). While the Company anticipates that the pilot program "should" improve the performance of circuits, it was also unable to provide an estimate of any such improvement (Exh. DPU 28-9). Given the speculative nature of the costs and any improvements, it would be premature to allow recovery of any costs related to a municipal hazard tree pilot program at this time.

In addition, the Department has granted a five-year PBR (see Section IV.D.5.a above), and, as such, the Company should have the incentive to continue to improve its RTW Program, including designing better methods to manage municipal tree removals more efficiently. Moreover, the Department notes that approval of the municipal hazard tree removal pilot program would also create an administrative burden on the Department, the Attorney General, and other intervenors.

Based on these factors, the Department finds that the recovery of costs related to the proposed municipal hazard tree removal pilot program is not in the interest of the ratepayers. Therefore, the Department disallows any cost recovery related to the proposed municipal hazard tree removal pilot program. The Company shall file a revised RTW Program tariff consistent with these findings.

XII. EXOGENOUS COST PROPERTY TAX PROPOSALS

A. Introduction

NSTAR Electric seeks to recover incremental property tax expenses resulting from cities and towns in the Company's service area adopting a hybrid "reproduction cost new less depreciation" ("RCNLD") and net book value ("NBV") method[152] of assessing the value of personal property. The Company requests recovery through two separate exogenous cost provisions. First, the Company seeks to recover $8,314,371 in total property taxes assessed by Springfield for fiscal years 2012 through 2015 under the exogenous cost provision of a settlement reached in docket NSTAR/Northeast Utilities Merger, D.P.U. 10-170-B (2012) (Exhs. ES-REVREQ-1, at 182, 184-185, 190-191; ES-REVREQ-6(a), Sch. 1). Second, the

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[152] The hybrid RCNLD/NBV method is based on 50 percent of RCNLD valuations and 50 percent of NBV valuations (Exh. ES-REVREQ-1, at 135). The hybrid RCNLD/NBV method uses the property tax expense as reported on the town's most recent property tax bills, adjusted to recognize any changes in personal property valuations (Exh. ES-REVREQ-1, at 135).

Company seeks to recover $30,006,340 in property taxes attributable to fiscal years 2021 and 2022 and half of fiscal year 2023, through the exogenous cost provision of the Company's current PBR mechanism (Exhs. ES-REVREQ-1, at 182, 191-199; ES-REVREQ-6(a), Sch. 2 (Supp.); DPU 16-1 (Rev.)). The Department will address each of these requests separately below.

B. Merger Settlement

1. Introduction

In D.P.U. 10-170-B at 2, 107, the Department approved a proposed settlement ("Merger Settlement") to merge NSTAR Electric and NSTAR Gas, along with their parent holding company NSTAR, and the former WMECo, along with its parent holding company Northeast Utilities.[153] As part of its decision, the Department approved a rate freeze applicable to the base distribution rates of NSTAR Electric, NSTAR Gas, and WMECo, so that base distribution rates in effect on January 1, 2012, remained in place until January 1, 2016. D.P.U. 10-170-B at 18-19, 107.

Pursuant to Article II (5) of the Merger Settlement, NSTAR Electric may seek exogenous cost recovery of incremental property taxes incurred during the rate freeze (i.e., January 1, 2012 through December 31, 2015) associated with the adoption by municipalities of the hybrid RCNLD/NBV method of assessing the value of personal property, provided that the incremental expense meets the minimum annual threshold for

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[153] Pursuant to 220 CMR 1.10(3), the Department incorporates by reference the Merger Settlement filed and approved in D.P.U. 10-170-B.

exogenous costs. The Merger Settlement provides that the dollar threshold for qualification as an exogenous factor in any calendar year covered by the Merger Settlement shall be determined by multiplying the total distribution revenues of that year by a factor of 0.003212 (Merger Settlement, Art. II (5)). The Merger Settlement is silent with respect to the method to be used to recover exogenous costs.

In D.P.U. 17-05, the former WMECo first sought to recover the aforementioned incremental property taxes assessed by Springfield as an exogenous cost pursuant to the Merger Settlement. D.P.U. 17-05, at 521-522.[154] At the time, WMECo had filed appeals of the Springfield tax assessments to the Appellate Tax Board, which still were pending. D.P.U. 17-05, at 523-524. As such, the Department denied WMECo's request to recover incremental property taxes pursuant to the Merger Settlement. The Department determined that because WMECo still was engaged in the appeals process after the denials of its tax abatement requests, we were unable to assess whether at the end of the appeals process there would be any incremental taxes and, if so, whether the amounts would be above the annual threshold subject to recovery from ratepayers as exogenous costs. D.P.U. 17-05, at 524. Thus, the Department decided not to consider WMECo's request for recovery of incremental property taxes as an exogenous cost at that time, and instead determined that, once all

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[154] Springfield had transitioned to the hybrid RCNLD/NBV well before March 26, 2019, the date that the Department of Revenue issued a Local Finance Opinion detailing a change in guidance from the Bureau of Local Assessment on the appropriate method of valuation for purposes of local property tax assessment (Exhs. ES-REVREQ-1, at 184; DPU 54-5, at 1). The Local Finance Opinion is discussed further in Section XII.C.3 below.

appeals were exhausted, WMECo should file a separate petition seeking exogenous cost recovery of any incremental property tax assessed using the hybrid RCNLD/NBV method from 2012 through 2015. D.P.U. 17-05, at 524.

2. Company Proposal

In the instant case, NSTAR Electric renews the former WMECo's previous request to recover $8,314,371 in incremental property taxes from 2012 through 2015 pursuant to the Merger Settlement (Exhs. ES-REVREQ-1, at 184-185; ES-REVREQ-6(a), Sch. 1). The Company proposes to amortize the property tax recovery over a five-year period at an annual amount of $1,662,874 (Exhs. ES-REVREQ-1, at 190; ES-REVREQ-2, Sch. 26 (Rev. 4)). NSTAR Electric argues that the annual amount of incremental property taxes meets the exogenous cost recovery standard under the Merger Settlement and that all of the Company's appeals have been exhausted (Company Brief at 301-302). No intervenor specifically addressed the Company's proposal on brief.

3. Analysis and Findings

Since the Department's decision in D.P.U. 17-05, the Company's challenges to the Springfield incremental tax assessments have been unsuccessful. In particular, in May 2020, the Appellate Tax Board rejected WMECo's appeals of the 2012 and 2013 assessments. Western Massachusetts Electric Company v. Board of Assessors of the City of Springfield, Appellate Tax Board, Docket Nos. F315550, F319349 (May 20, 2020). That decision subsequently was upheld by the Massachusetts Appeals Court in a Rule 23.0 Memorandum and Order issued in April 2022. Western Massachusetts Electric Company v. Board of

Assessors of Springfield, 100 Mass. App. Ct. 1131 (Mass. App. Ct. 2022). In June of this year, the Supreme Judicial Court denied further appellate review of the matter. Western Massachusetts Electric Company v. Board of Assessors of Springfield, FAR-28794, 2021-P-0596 (June 2, 2022). Following the Appeals Court decision, the Company paid the outstanding tax liability to Springfield, including interest (Exhs. DPU 54-8, at 2 & Att.; AG 12-18).[155]

Further, since the decision in D.P.U. 17-05, the Department has had another opportunity to evaluate a request for exogenous cost recovery pursuant to the Merger Settlement. In D.P.U. 19-120, at 326-328, NSTAR Gas requested recovery pursuant to the Merger Settlement of incremental property tax expenses assessed by the City of Worcester and Town of Westborough from 2012 through 2015. In that Order, the Department determined that that NSTAR Gas did not need to exhaust all of its appeals before seeking exogenous cost recovery of incremental property taxes pursuant to the Merger Settlement and could begin to recover incremental property taxes associated with Worcester and Westborough for 2012 through 2015. D.P.U. 19-120, at 334-335.

The Department has given careful consideration to NSTAR Electric's request in the instant case. The Merger Settlement expressly allows the Company to seek recovery of the incremental tax amounts associated with the change in property valuation for fiscal years

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[155] The Company's instant request to recover $8,314,371 in incremental property taxes assessed by Springfield for fiscal years 2012 through 2015 does not include an interest component (Exhs. DPU 54-1, Att.; DPU 54-8, at 2).

2012 through 2015, provided that the incremental expense satisfies the Department's exogenous cost standard in D.P.U. 96-50 (Phase I) and meets the minimum annual threshold for exogenous costs set forth in the Merger Settlement (Merger Settlement, Art. II (5)). We find that the incremental tax amounts satisfy the Department's exogenous cost standard and that the Company has demonstrated that for each fiscal year from 2012 through 2015, the amount of incremental property tax exceeded the Merger Settlement threshold (Exhs. ES-REVREQ-6(a), Sch. 1; DPU 54-1, Att.). D.P.U. 96-50 (Phase I), at 292. Further, in light of the treatment of the hybrid RCNLD/NBV method by the Massachusetts appellate courts, and consistent with our decision with respect to NSTAR Gas in D.P.U. 19-120, we find that the Company no longer needs to pursue additional appeals before seeking exogenous cost recovery of incremental property taxes pursuant to the Merger Settlement.[156] Rather, we conclude that it is reasonable and appropriate for the Company to begin to recover the incremental property taxes associated with Springfield for fiscal years 2012 through 2015.

The Merger Settlement does not describe the manner in which these costs shall be recovered (<u>see</u> Merger Settlement, Art. II (5)). As noted above, NSTAR Electric proposes to amortize the recovery of $8,314,371 in incremental property taxes over five years at an

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[156] While the Company refers to its appeals as "exhausted," we note that the recent decision of the Massachusetts Appeals Court appears confined to the Springfield incremental tax assessments for fiscal years 2012 and 2013 (Exh. DPU 54-7, Att. (a) at 2). Nonetheless, based on the considerations above, the Company may begin to recover the entire amount attributable to fiscal years 2012 through 2015.

annual amount of $1,662,874 (Exhs. ES-REVREQ-1, at 184-185, 190; ES-REVREQ-6(a), Sch. 1; ES-REVREQ-2, Sch. 26 (Rev. 4)). In Section IV.D.5.a above, the Department approved a PBR plan for NSTAR Electric with a five-year term. As such, the Department finds that it is reasonable and appropriate to amortize the recovery of the incremental property taxes over the same term as the PBR plan. D.P.U. 19-120, at 337. To the extent the Company recovers any or all of the incremental property taxes relative to fiscal years 2012 through 2015 as a result of an abatement/appeals process, it shall refund customers the incremental property tax amounts through the exogenous cost provision of its PBR plan (Exhs. ES-REVREQ-1, at 190-191; DPU 54-2). D.P.U. 19-120, at 337.

Based on the above considerations, the Department approves the Company's exogenous cost property tax proposal relative to the Merger Settlement. The Company shall amortize the recovery of $8,314,371 in incremental property taxes over five years at an annual amount of $1,662,874.

C. D.P.U. 17-05 PBR Mechanism

1. Introduction

In D.P.U. 17-05, at 370-414, the Department approved a PBR mechanism with a five-year term, which allows NSTAR Electric to adjust its distribution rates annually through the application of a revenue-cap formula that accounts for, among other factors, inflation and exogenous events, either positive or negative. D.P.U. 17-05, at 381-399. Since the decision in D.P.U. 17-05, the Department has approved four annual PBR adjustments for the Company. NSTAR Electric Company, D.P.U. 21-106 (2021); NSTAR Electric Company, D.P.U. 20-96 (2020); NSTAR Electric Company, D.P.U. 19-115 (2019); D.P.U. 18-101. In NSTAR Electric's most recent annual PBR adjustment filing, D.P.U. 21-106, the Company included, for the first time, a request to recover $11.8 million in additional property taxes incurred in fiscal year 2021 (i.e., July 2020 through June 2021) through the end of calendar year 2021 and associated with what the Company maintained was an exogenous event resulting from a change in the valuation method used by certain municipalities to assess utility property. D.P.U. 21-106, at 3, citing Exhs. ES-RWF/ANB at 15-22; ES-RWF-ANB-1, at 1-2; ES-RDC-1, Sch. 2; see also D.P.U. 21-106, Exhs. ES-RWF/ANB-3, at 1; DPU 2-1. Subsequently, the Company proposed to remove these costs from the PBR adjustment and, instead, file a future request for exogenous cost recovery in a separate proceeding. D.P.U. 21-106, at 11, citing NSTAR Electric Filing Letter at 1-2; Exhs. ES-RWF/ANB-1 (Mitigated); DPU 2-2, Att. (a)). The Department approved NSTAR Electric's proposal, and we noted that we would review any request for exogenous cost recovery in a separate proceeding to be filed by the Company. D.P.U. 21-106, at 11.

In the instant proceeding, NSTAR Electric's initial filing included a request to recover $30,006,340 in total additional property taxes though the exogenous cost provision of the Company's current PBR mechanism, comprised of the incremental property taxes that initially were presented in D.P.U. 21-106 and subsequently withdrawn, plus incremental property taxes attributable to fiscal year 2022 and half of fiscal year 2023 (Exhs. ES-REVREQ-1, at 182, 191-199; ES-REVREQ-6(a), Sch. 2, at 1 (Supp.); DPU 16-1, Att. at 1 (Rev.)). The Company proposed to begin recovering approximately $8 million attributable to fiscal year 2021 property taxes through the PBR adjustment factor for effect on January 1, 2023 (Exh. ES-REVREQ-1, at 197). The Company stated that any over/under recovery of the prior-period expenses would be reconciled in the next PBR adjustment filing on September 15, 2023, with carrying charges calculated at the prime rate (Exh. ES-REVREQ-1, at 197).

On September 23, 2022, the Company submitted its revised fifth annual PBR filing pursuant to the PBR plan approved in D.P.U. 17-05. The Department docketed the matter as D.P.U. 22-120. In that filing, the Company does not propose a PBR adjustment to base distribution revenues. NSTAR Electric Company, D.P.U. 22-120, Exhs. ES-RDC, at 3; ES-ANB-1, at 1. Rather, NSTAR Electric proposes to recover through base distribution rates, the incremental property taxes incurred in fiscal year 2021, 2022, and the first half of 2023, which the Company states amounts to $30,187,653. D.P.U. 22-120, Exhs. ES-ANB at 7-8, 21-30 (Rev.); DPU 4-3, Att. The Company makes essentially the same statements in that filing to support its requested recovery as in the instant case. D.P.U. 22-120, Exh. ES-ANB at 15, 21-30 (Rev.).[157] The Company also requests that the Department make

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[157] The Company attributes the higher amount requested for recovery in D.P.U. 22-120 to final property tax information from two municipalities that was not available at the time that exhibits were prepared in the instant case, and to a recalculation of totals to conform to the Department's recent decision in Eversource Gas Company of Massachusetts, D.P.U. 22-122 (October 31, 2022) and NSTAR Gas Company, D.P.U. 22-121 (October 31, 2022). D.P.U. 22-120, Exhs. DPU 1-1, at 4; DPU 4-3 & Att.

a finding in the instant case that an exogenous event has occurred pursuant to the PBR plan approved in D.P.U. 17-05, and then to allow the actual implementation of the cost recovery in D.P.U. 22-120. D.P.U. 22-120, Exhs. ES-ANB at 7-8 (Rev.); DPU 1-1, at 1-2.

2. Positions of the Parties

a. Attorney General

The Attorney General argues that the Department should deny the Company's proposal to treat increased property valuations as exogenous costs under the Company's current PBR plan (Attorney General Brief at 180; Attorney General Reply Brief at 31). The Attorney General contends that none of the incremental costs associated with various municipalities using a hybrid RCNLD/NBV method meet the exogenous cost threshold set forth in the Company's PBR mechanism (Attorney General Brief at 180-181, citing Exh. ES-REVREQ-6(b), Sch. 4.). Further, the Attorney General submits that each municipality's adoption of an alternative to the NBV property tax assessment method should be considered a separate exogenous event, particularly since various municipalities adopted an alternative method at different times (Attorney General Reply Brief at 31-32). In this regard, the Attorney General argues that the Department of Revenue ("DOR") has provided guidance to municipalities on adopting an alternative to the NBV tax assessment method but does not require cities and towns to use the alternative method (Attorney General Reply Brief at 32-33, citing Exh. ES-REVREQ-6(a), Sch. 4, at 3; Sch. 5, at 7). Finally, the Attorney General asserts that the Department previously rejected the notion that incremental property tax amounts across multiple municipalities should be combined and totaled for purposes of meeting the exogenous cost threshold in the PBR mechanism (Attorney General Brief at 180-181, citing Eversource Gas Company of Massachusetts, D.P.U. 21-112-A at 8-11 (June 3, 2022); D.P.U. 20-120, at 349-350; D.P.U. 19-120, at 332-338; D.P.U. 18-150, at 421-422; D.P.U. 17-05, at 558-559; Attorney General Reply Brief at 31-34).

b. TEC and PowerOptions

TEC and PowerOptions argue that the Department should continue to evaluate exogenous cost recovery of incremental property taxes on a non-cumulative, individual municipality basis and not combine totals from various municipalities for purposes of meeting the exogenous cost threshold (TEC/PowerOptions Brief at 13, citing D.P.U. 20-120, at 349-350). Further, TEC and PowerOptions assert that only NSTAR Electric can protect its ratepayers from "overly aggressive" property tax valuations, and it is imperative that the Company continue to vigorously contest unreasonably high assessments (TEC/PowerOptions Brief at 13).

c. Company

The Company argues that when costs are interrelated and caused by a single exogenous event, the costs should be calculated in the aggregate (Company Brief at 304-305, citing D.P.U. 18-101, at 20-21; Boston Gas Company, D.T.E. 05-66, at 11-13 (2005); Colonial Gas Company, D.T.E. 00-73, at 19-22 (2001)). In this regard, NSTAR Electric contends that the incremental property taxes at issue arise from DOR's decision to "formally transition" from the traditional NBV method of utility property valuation to the hybrid RCNLD/NBV approach, and that DOR's directives constituted a single exogenous event because it caused large numbers of municipalities (specifically, 187 of 194 municipalities) to change their tax valuation method and increase the Company's property taxes (Company Brief at 301-306).

According to the Company, to focus on each individual municipality's tax assessment as a separate and distinct exogenous event is legally flawed, as the exogenous event is not the municipality's decision to change the property tax valuation, but rather the municipalities need to comply with DOR's directive (Company Brief at 306-307; Company Reply Brief at 34-35). In this regard, the Company contends that legal "causation principles" point to DOR's purported directives as being the direct or proximate cause of 187 municipalities changing their valuation method and increasing property taxes beginning in fiscal years 2021 and 2022 (Company Brief at 306, citing Lynn Gas & Electric Company v. Meriden Fire Insurance Company, 158 Mass. 570, 575 (1893); Jussim v. Massachusetts Bay Insurance Company, 415 Mass. 24, 27 (1993); Company Reply Brief at 35-36).

Moreover, the Company argues that the Department has allowed exogenous cost recovery based on aggregate costs. For example, NSTAR Electric contends that the Department determined that the March 2018 Nor'Easter storm event, during which the Company was in a continuous state of storm preparation and restoration, should be treated as single major storm event for exogenous cost recovery (Company Reply Brief at 37-38, citing D.P.U. 18-101, at 11-12, 20-21). Thus, the Company claims that the Department should treat as a single exogenous event, the increase in incremental property taxes among various municipalities since the issuance of DOR's directives in 2019 (Company Brief at 307;

Company Reply Brief at 38). Based on the above considerations, the Company asserts that the Department should allow NSTAR Electric to recover $30,006,340 in incremental property taxes pursuant to the exogenous cost provision in the Company's current PBR mechanism (Company Brief at 307).

3. Analysis and Findings

In D.P.U. 17-05, at 395-398, the Department approved an exogenous cost factor as a component of the Company's PBR plan. Pursuant to NSTAR Electric's current PBR tariff, the Company must provide supporting documentation and rationale demonstrating that the proposed exogenous cost meets the following criteria: (1) the cost change must be beyond the Company's control; (2) the cost change arises from a change in accounting requirements or regulatory, judicial, or legislative directives or enactments; (3) the cost change is unique to the electric distribution industry as opposed to the general economy; and (4) the cost change meets a threshold of significance for qualification. M.D.P.U. No. 59(E) at § 1.08.[158] The significance threshold for exogenous costs was set at $5 million for each individual event in

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[158] The Department has defined exogenous costs as positive or negative cost changes actually beyond a company's control and not reflected in the GDP-PI. D.P.U. 94-50, at 172-173. These include, but are not limited to, incremental costs resulting from: (1) changes in tax laws that uniquely affect the relevant industry; (2) accounting changes unique to the relevant industry; and (3) regulatory, judicial, or legislative changes uniquely affecting the industry. D.P.U. 96-50 (Phase I) at 291; D.P.U. 94-50, at 173. In D.P.U. 17-05, at 396, we determined that NSTAR Electric's definition of exogenous costs in its proposed PBR tariff was consistent with the definition adopted by the Department in D.P.U. 94-50.

calendar year 2018, and thereafter was to be adjusted annually based on changes in GDP-PI. D.P.U. 17-05, at 397-398; M.D.P.U. No. 59(E) at § 1.08.

In D.P.U. 21-107-A at 18-19, the Department determined that a Local Finance Opinion issued by DOR in March 2019 (see n.154 above) constituted a regulatory policy change that lowered the burden of using a method other than NBV and induced a significant number of municipalities in NSTAR Gas' service area to change their valuation method. Further, we determined that DOR's regulatory policy change on NBV, while not mandating a specific valuation method, has driven widespread adoption by municipalities of an alternative property valuation method resulting in an incremental change in property tax expense in excess of NSTAR Gas' significance threshold. D.P.U. 21-107-A at 19. In addition, we found that the cost increases satisfy the criteria for an exogenous event because NSTAR Gas had incurred a cost change that: (1) arose from DOR's 2019 state-wide regulatory directive that it would no longer treat NBV as the default method for valuation of utility property taxes or give presumptive validity to valuations based on NBV; (2) was beyond NSTAR Gas' control; (3) was unique to the utility industry as opposed to the general economy; and (4) met NSTAR Gas's significance threshold. D.P.U. 21-107-A at 19. The Department distinguished our prior determinations that examined the significance of property tax expense changes driven by municipalities' independent decisions to change their method of property valuation and not driven by DOR's change in regulatory policy governing the utility industry. D.P.U. 21-107-A at 19-20.

We find that the same standard applied in D.P.U. 21-107-A to NSTAR Gas should apply to NSTAR Electric's proposal in the instant case. The record in the instant proceeding shows that at the time of NSTAR Electric's last base distribution rate case, D.P.U. 17-05, only six municipalities in the Company's service area had transitioned from NBV to the hybrid RCNLD/NBV method of assessing property taxes (Exh. DPU 16-1, Att. at 9-11 (Rev.)). The Company has demonstrated that 187 municipalities now have transitioned from NBV to the hybrid RCNLD/NBV method since the Department's Order in D.P.U. 17-05 (Exhs. ES-REVREQ-6(a), Sch. 2, at 9-11 (Supp.); DPU 16-1, at 2 & Att. at 9-11 (Rev.)). As such, we find that the Local Finance Opinion issued by DOR in March 2019 constituted a regulatory policy change that led a significant number of municipalities within NSTAR Electric's service area to change their valuation method. Further, we conclude that DOR's action was beyond NSTAR Electric's control and was unique to the utility industry as opposed to the general economy. In addition, NSTAR Electric's supporting documentation appears to show that the cost change resulting from DOR's actions meets the Company's significance threshold (Exhs. ES-REVREQ-6(a), Sch. 2, at 8 (Supp.); DPU 16-1, Att. at 8 (Rev.)).

The final determination of the amount of incremental property taxes eligible for recovery will be made in docket D.P.U. 22-120. Consistent with the findings in D.P.U. 21-107-A at 20, NSTAR Electric will need to demonstrate that its proposed exogenous cost adjustments include only the incremental property tax expense that arises from the exogenous event. Further, the Company must isolate the impact of municipalities' adoption of the hybrid RCNLD/NBV method following DOR's issuance of the Local Finance Opinion and follow the terms of the PBR tariff to implement the exogenous cost change. D.P.U. 21-107-A at 20. Once approved by the Department, the amount of the cost change shall be amortized over two years and recovered through a separate factor. We find this method of recovery is reasonable and appropriate given that the permanent increase in property tax expense due to the hybrid RCNLD/NBV method will be reflected in base distribution rates as a result of our Order today (see Exh. ES-REVREQ-27, Sch. 27 (Rev. 4); Department Schedule 7 below).

XIII. SERVICE QUALITY PERFORMANCE EXEMPTION

A. Introduction

The Department approved the current SQ Guidelines applicable to EDCs and local gas distribution companies in D.P.U. 12-120-D. The SQ Guidelines establish performance metrics and benchmarks against which the EDCs and local gas distribution companies must measure their performance annually. D.P.U. 12-120-D. The SQ Guidelines established the following metrics with an associated penalty for EDCs: SAIDI;[159] SAIFI;[160] CKAIDI;

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[159] SAIDI means the total duration of customer interruptions in minutes divided by the total number of customers served by the EDC, expressed in minutes per year. SAIDI characterizes the average length of time that customers are without electric service during the reporting period. D.P.U. 12-120-D, Att. A at 6.

[160] SAIFI means the total number of customer interruptions divided by the total number of customers served by the EDC, expressed in number of interruptions per customer per year. SAIFI characterizes the average number of sustained electric service interruptions for each customer during the reporting period. D.P.U. 12-120-D, Att. A at 6.

CKAIFI; Service Appointments Kept As Scheduled; Customer Complaints; and Customer Credit Cases. D.P.U. 12-120-D, Att. A. The SQ Guidelines require EDCs to annually report their performance for each of these metrics and pay monetary penalties if their performance does meet the applicable benchmarks. D.P.U. 12-120-D at 7-16. The EDCs must include all relevant data when calculating their annual performance for each metric, unless some data has been excluded either because it meets the definition of an "Excludable Major Event" or a company requested, and the Department approved, a limited exemption. D.P.U. 12-120-D, Att. A at 4, 25. The SQ Guidelines define the term Excludable Major Event as follows:

> "Excludable Major Event" means a major Interruption event that meets one of the three following criteria: (1) the event is caused by earthquake, fire or storm of sufficient intensity to give rise to a state of emergency proclaimed by the Governor (as provided under the Massachusetts Civil Defense Act); (2) any other event that causes an unplanned Interruption of service to fifteen percent or more of the Electric Company's total customers in the Electric Company's entire service territory; or (3) the event was a result of the failure of another Company's transmission or power supply system. Excludable Major Events apply to all SQ reliability metrics. Notwithstanding the foregoing criteria, an Interruption event caused by extreme temperature condition is not an Excludable Major Event.

D.P.U. 12-120-D, Att. A at 4. Excludable Major Events are the only events automatically excluded from the calculation of all SQ metrics. D.P.U. 12-120-D, Att. A at 12. The SQ Guidelines, however, allow EDCs to request a limited exemption from a particular portion of the SQ Guidelines, including circumstances where an event does not meet the definition of Excludable Major Event. D.P.U. 12-120-D, Att. A, at 25. For example, the Department may grant an exemption from a particular metric or metrics if extraordinary circumstances arise during an outage event that render prompt service restoration beyond an EDC's reasonable control. D.P.U. 12-120-D, Att. A at 25; 2020 Electric Service Quality Reports, D.P.U. 21-SQ-10 through 21-SQ-13, at 6 (February 4, 2022), citing Petition by Local Gas Distribution Companies for Limited Waiver of Service Quality Guidelines, D.P.U. 15-56, at 5 (2016).

B. Company Proposal

NSTAR Electric requests that, for SQ reporting purposes, the Department allow storms with SAIDI values more than four standard deviations from the Company's mean to be excluded from the computation of SAIDI/SAIFI performance for that year (Exh. ES-CAH/DPH-1, at 106-107). The Company's proposal would not change the current definition of Excludable Major Event, but instead would create a second circumstance under which single days automatically would be excluded from metric calculations (Exh. NG 1-1). Thus, under the Company's proposal, events with customer outages exceeding the 15-percent threshold still would be excluded from SAIDI/SAIFI reporting pursuant to the Excludable Major Event definition, and events with less than 15 percent customer outages, but with a SAIDI value more than four standard deviations from the mean, also would be excluded automatically (Exh. NG 1-1).

C. Positions of the Parties

1. National Grid (electric)

National Grid (electric) supports NSTAR Electric's proposal and argues that the Department's exclusion criteria should be refined to recognize that EDCs have made substantial investments in their systems over the past 20 years, yet significant storms continue to occur that, because of the investments, do not trigger the Excludable Major Event threshold (National Grid (electric) Brief at 6-10, citing Exhs. ES-CAH/DPH-1, at 102-104; ES-CAH/DPH-2; NG-1, at 9-10; NG 1-1). According to National Grid (electric), the current three-year rolling average option to mitigate or eliminate penalties neither rectifies the influence of weather conditions beyond the control of the companies nor accounts for the effect of system improvements and an increasing customer base (National Grid (electric) Brief at 4-5, citing Exh. NG-1, at 7-9). National Grid (electric) asserts that NSTAR Electric's proposal more appropriately recognizes the impact of system improvements and an increased customer base over the past 20 years (National Grid (electric) Brief at 5-6, citing Exh. ES-CAH/DPH-1, at 101).

Further, National Grid (electric) contends that the Company's proposal is not a request for the Department to replace the existing definition of Excludable Major Event, but rather to add a second-tier test that "would work in conjunction with the existing definition of Excludable Major Event" (National Grid (electric) Brief at 7-8, citing Exh. NG 1-1). National Grid (electric) asserts that NSTAR Electric's proposed automatic exclusion would provide a bridge until a future generic proceeding, wherein the Department can reevaluate the current 15-percent exclusion threshold as part of a broader inquiry into updating the SQ Guidelines (National Grid (electric) Brief at 8, 15, citing Exhs. ES-CAH/DPH-1, at 103-105; NG-1, at 14-16; NG 1-1).[161]

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[161] National Grid (electric) argues that in future generic SQ proceedings, the Department should reduce the 15-percent threshold criteria because only extraordinarily large weather impacts are excluded from the day-to-day computation of "reliability," which

2. Company

NSTAR Electric argues that the definition of an Excludable Major Event has remained unchanged for 20 years, despite the technological and operational improvement to the Company's system over that same time period (Company Brief at 93, citing Exh. ES-CAH/DPH-1, at 101). In this regard, the Company contends that it has improved the reliability of its distribution system such that the number of customers interrupted per storm has decreased by 30 percent over the past ten years (Company Brief at 92, citing Exh. ES-CAH/DPH-1, at 99-100). NSTAR Electric asserts, however, that because of the decrease in customer interruptions, fewer storms meet the 15-percent threshold for an Excludable Major Event, yet still cause significant damage and, therefore, are included in the annual SAIDI and SAIFI calculations (Company Brief at 92, citing Exh. ES-CAH-DPH-1, at 100). According to NSTAR Electric, including such data in the SAIDI and SAIFI calculations gives the false impression that reliability is worsening and the Company's SAIDI and SAIFI performance is declining (Company Brief at 92-93, citing Exh. ES-CAH/DPH 1, at 99-100). NSTAR Electric asserts that its proposal accounts for the Company's reliability improvements and increased customer counts (Company Brief at 93-94, citing Exh. ES-CAH/DPH-1, at 101).

National Grid (electric) claims is not a valid methodological approach for SAIDI/SAIFI computations (National Grid (electric) Brief at 8, citing Exh. NG 1-1 n.5).

NSTAR Electric argues that its proposal is supported by a comprehensive analysis of the SAIDI and SAIFI performance measures, which demonstrate that severe weather events have not been properly excluded from the computation of SAIDI and SAIFI for measuring day-to-day reliability (Company Brief at 94, citing Exhs. ES-CAH/DPH-1, at 103-104; ES-CAH/DPH-2). In particular, the Company asserts that its analysis shows that there are weather events that are causing days with SAIDI performance that are four standard deviations from the average daily performance but are not reaching the 15-percent threshold of customers experiencing a service interruption (Company Brief at 93-94, citing Exhs. ES-CAH/DPH-1, at 103-104; ES-CAH/DPH-2). Finally, the Company contends that its proposal to exclude days with a SAIDI value exceeding four standard deviations from the mean is intended to provide a bridge until the Department opens a future generic proceeding to address the SQ Guidelines (Company Brief at 94, citing Exhs. NG 1-1; NG 1-4).

D. Analysis and Findings

NSTAR Electric proposes to exclude data from event days that may indicate severe distribution system damage, yet do not meet the current definition of an Excludable Major Event (Exhs. ES-CAH/DPH-1, at 106-107; NG 1-1). NSTAR Electric argues that, unlike the current definition of Excludable Major Event, the Company's proposal accounts for reliability improvements and increased customer counts on the distribution system (Company Brief at 93-94, citing Exh. ES-CAH/DPH-1, at 101).

The Department recognizes that the definition of Excludable Major Events has remained unchanged for over 20 years and may no longer accurately account for emergency events resulting in severe damage, or for the changes to distribution systems and increased customer counts. Service Quality Guidelines for Electric Distribution Companies and Local Gas Distribution Companies, D.T.E. 99-84, Att. at 2 (2001). The Department intends to open a proceeding within the next year to evaluate the current SQ Guidelines, at which time the EDCs and relevant stakeholders will have an opportunity to comment on proposed refinements to the Guidelines. In the interim, however, we find that it is reasonable and appropriate to approve the Company's proposal. The Company's proposal and attendant analysis demonstrates that events with SAIDI values greater than four standard deviations from the mean tend to cause significant damage, despite not reaching the current customer outage criteria for an Excludable Major Event (Exhs. ES-CAH/DPH-1, at 103-106; ES-CAH/DPH-2). As such, including these event days in the SAIDI/SAIFI calculations may skew NSTAR Electric's overall performance results and may not accurately reflect the Company's efforts to improve reliability of the distribution system. While we recognize that under the current SQ Guidelines NSTAR Electric may seek specific exemptions for severe weather events that do not meet the definition of an Excludable Major Event but nonetheless have a severe impact on a utility's distribution system, we find that the Company's proposal presents a straightforward, verifiable, and efficient alternative to such an exemption (Exhs. ES-CAH/DPH-1, at 104-107; ES-CAH-DPH-2). In this regard, we do not consider the Company's proposal as a permanent change to the definition of what constitutes an Excludable Major Event under the current SQ Guidelines. Rather, the proposal is an interim measure that will be reevaluated over time until the Department updates the SQ Guidelines.

Based on these considerations, the Department approves the Company's proposal to exclude from the annual SAIDI and SAIFI metric calculations, event days where the SAIDI values exceed the mean plus four standard deviations. As the SQ Guidelines apply to each EDC, so too will this event day exemption, effective immediately. More specifically, the EDCs may begin applying this exemption in their 2022 annual SQ report filings, for the full 2022 calendar year of data. The EDCs shall follow the method for calculating the event day exemption as presented by the Company in Exhibit ES-CAH/DPH-2. Consistent with the SQ Guidelines as they relate to Excludable Major Events, the EDCs shall demonstrate in their annual SQ report filings why any data excluded pursuant to this event day exemption qualifies for exclusion and calculate annual SAIDI and SAIFI performance both with and without the excluded data. The Department will evaluate each EDC's annual SAIDI and SAIFI performance using the values with the relevant event day exemptions, provided the companies file all appropriate calculations, assumptions, and data in their respective annual SQ report filings.

As noted above, the Department plans to revisit the SQ Guidelines in the next year, at which point we will further evaluate the event day exemption and its effectiveness at providing a more accurate impression of reliability improvements and increased customer counts on the EDCs' distribution systems. The Department may modify or eliminate the event day exemption based on that evaluation, or during our review of the annual SQ reports should circumstances warrant.

XIV. SMART PROGRAM AND SOLAR EXPANSION PROGRAM INVESTMENTS

A. SMART Program Investments

1. Introduction

On September 12, 2017, pursuant to G.L. c. 164, § 94, Fitchburg Gas and Electric Light Company d/b/a Unitil ("Unitil"), National Grid (electric), and NSTAR Electric and the former WMECo (collectively "Distribution Companies") filed with the Department a joint petition for approval of a model Solar Massachusetts Renewable Target ("SMART") Provision tariff ("SMART Provision") to implement An Act Relative to Solar Energy and DOER regulations ("SMART Program"). St. 2016, c. 75, § 11(b); G.L. c. 25A, § 6; 225 CMR 20.00. The Department docketed the petition as D.P.U. 17-140.[162]

On September 26, 2018, the Department issued a final Order approving the SMART Provision. Joint Petition for Approval of Model Solar Massachusetts Renewable Target Tariff, D.P.U. 17-140-A, Order Approving Model SMART Provision (September 26, 2018) ("SMART Order"). In the SMART Order, the Department determined that the Distribution Companies may recover the following: (1) the incremental O&M and capital costs necessary to meet the SMART Program's objectives; (2) an estimate of the net cost of the incentive

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[162] The Attorney General, DOER, Acadia Center, BCC Solar Advantage, Inc., Genbright, LLC, and Solar Energy Industries Association were granted intervenor status. Joint Petition for Approval of Model Solar Massachusetts Renewable Target Tariff, D.P.U. 17-140-A, Order Approving Model SMART Provision at 2-3 (September 26, 2018). Associated Industries of Massachusetts was granted limited participant status. D.P.U. 17-140-A, Order Approving Model SMART Provision at 3 (September 26, 2018).

payments, alternative on-bill credits ("AOBCs"), and revenues generated from the SMART Program; and (3) a reconciliation adjustment with applied interest. SMART Order at 143-160. These costs are to be recovered through a SMART factor consistent with certain directives and the formula established in each Distribution Company's respective tariff. SMART Order at 181-190. The Distribution Companies are required to make an annual cost recovery and reconciliation filing for the SMART factor on or before November 1st of each year, for effect January 1st of the next year. SMART Order at 197. NSTAR Electric's current SMART tariff is M.D.P.U. No. 74D.

In accordance with the directives in the SMART Order, the Company filed annual SMART factor filings in dockets D.P.U. 18-132, D.P.U. 19-125, D.P.U. 20-131, and D.P.U. 21-134. The Department issued Phase I Orders in each docket and approved the Company's proposed SMART factors, subject to further investigation. NSTAR Electric Company, D.P.U. 21-134, at 4-5 (2021); NSTAR Electric Company, D.P.U. 20-131, at 5-6 (2020); NSTAR Electric Company, D.P.U. 19-125, at 5-6 (2019); NSTAR Electric Company, D.P.U. 18-132, at 4-5 (2018). On May 21, 2020, the Department issued a final Order approving the 2019 SMART Program costs, subject to certain directives. D.P.U. 18-132-A at 3 8. At the time of the initial filing in the instant proceeding, the Department had not issued final Orders in D.P.U. 19-125, D.P.U. 20-131, and D.P.U. 21-134. The Department subsequently issued a final Order in D.P.U. 21-134. D.P.U. 21-134-A (November 29, 2022).

2. Company Proposal

The Company proposes to transfer the recovery of expenses for ESC net plant balances associated with $11.4 million in SMART Program capital additions, placed in service through December 31, 2021, to base distribution rates (Exhs. ES-REVREQ-1, at 41-42; ES-ADDITIONS-1, at 51; ES-ADDITIONS-7, Att. (a) (Supp).; DPU 14-2; DPU 39-20, at 1-2; DPU 39-21). The Company proposes to include the revenue requirement associated with those investments charged to the Company as Enterprise IT O&M expense, or $1,908,643, in the computation of the revenue requirement underlying base rates that become effective January 1, 2023 (Exhs. ES-REVREQ-1, at 22, 41-42; ES-REVREQ-4, Sch. 9 (Rev. 1)).[163] Thus, beginning January 1, 2023, the Company would recover the costs associated with the remaining un-depreciated SMART investments through distribution rates (Exh. DPU 39-20, at 2). The Company states that these costs represent IT system enhancements, including data interfaces and billing system modifications used to support an additional line item for the SMART factor on customer bills (Exhs. ES-ADDITIONS-1,

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[163] The Company included corresponding revenues of $1,893,718 associated with SMART Program expenses for purposes of reflecting the appropriate revenue deficiency (Exhs. ES-REVREQ-1, at 25; ES-REVREQ-2, Sch. 1, at 9; Sch. 6 (Rev. 4)). SMART Program revenues associated with the sale of product revenues (i.e., revenues from the sale of energy, forward capacity market, and sale of solar renewable energy credits) will continue to be included in the SMART mechanism, as well as, the: (1) incentive payments for RPS Class I renewable generation attributes and/or environmental attributes produced by a solar tariff generation unit; (2) AOBCs for energy generated by an AOBC generation unit; (3) the basis upon which incentive payments and AOBCs are determined; and (4) the recovery of any such incentive payments, AOBCs, and certain incremental administrative costs associated with the implementation and operation of the SMART Program (Exh. ES-REVREQ-1, at 25).

at 51; DPU 14-1). According to the Company, it has produced in the instant proceeding all of the documentation necessary for the Department to conduct a prudency review of these costs (Exhs. ES-ADDITIONS-1, at 51; ES-REVREQ-1, at 44; ES-ADDITIONS-7 & Supp.).

The Company notes, however, that it will not recover the revenue requirement earned under its SMART tariff prior to new base distribution rates taking effect due to the timing of the SMART filings, which go into effect on January 1st of each year and include a twelve-month lag between when investments are placed in service to when recovery begins (Exh. ES-REVREQ-1, at 42). Thus, the Company proposes for the earned revenue requirement to be recovered through the SMART tariff and after the effective date of new base distribution rates set in this proceeding (Exh. ES-REVREQ-1, at 42). Specifically, NSTAR Electric proposes that, by November 1, 2022, it will file its annual SMART Program filing for actual investments placed in service on or before August 30, 2022, and that the associated SMART factor will be effective January 1, 2023 through December 31, 2023 to allow for the recovery of the 2022 revenue requirement on the SMART Program costs (Exh. ES-REVREQ-1, at 42-43). Then, by November 1, 2023, the Company will file its annual SMART Program filing for actual investments placed in service on or before August 30, 2023, and the associated SMART factor will be effective January 1, 2024 through December 31, 2024, to allow for the recovery of the 2023 revenue requirement on the SMART Program costs (Exh. ES-REVREQ-1, at 43). At this point, the SMART factors no longer will recover investments that have been reflected in base rates as of January 1, 2023 (Exh. ES-REVREQ-1, at 43).

3. Positions of the Parties

The Attorney General argues that the Department should deny the Company's request to transfer to base distribution rates the costs associated with the SMART Program, as these costs already are recovered in reconciling mechanisms (Attorney General Brief at 113-116). Further, the Attorney General argues that the Department need not transfer costs into base distribution rates at this time because of the open SMART dockets (Attorney General Brief at 116). Rather, the Attorney General asserts that the Department should continue to adjudicate the SMART Program costs in the open SMART Program dockets (Attorney General Brief at 116).

The Company restates its SMART Program proposals on brief (Company Brief at 128, 135-136, 141, 389, 391). The Company, on brief, addresses the proposed roll-in of capital additions, but does not specifically address the Attorney General's arguments about the SMART Program investments (Company Brief at 52-53).

4. Analysis and Findings

In the SMART Order, the Department determined the categories of recoverable costs associated with the SMART Program, and the process by which the Company could recover such costs, after they have been reviewed and approved by the Department. SMART Order at 143-160, 181-190, 197. In particular, we determined that it was reasonable to allow recovery through the SMART factor of costs to upgrade IT and billing systems that are specifically related to SMART Program implementation. SMART Order at 150. Since that Order, the Company has recovered SMART-related costs through its SMART factor, subject to further investigation by the Department. D.P.U. 21-134, at 4-5; D.P.U. 20-131, at 5-6; D.P.U. 19-125, at 5-6; D.P.U. 18-132, at 4-5. As noted above, final Orders have issued in dockets D.P.U. 18-132 and D.P.U. 21-134.

In the instant proceeding, the Company requests that the Department conduct a prudency review of several years of SMART-related IT system enhancement capital additions and then transfer the unrecovered balance of these investments to base rates (Exhs. ES-ADDITIONS-1, at 51; ES-REVREQ-1, at 22, 41-42; DPU 39-20, at 1-2; DPU 39-21).[164] We decline to do so. First, we find that it is more appropriate and efficient to review all of the costs subject to recovery in the individual outstanding SMART Program dockets, rather than to undertake a piecemeal review of the IT-related capital costs. Next, as noted above, the Department already determined that recovery of certain IT-related costs, such as those proposed by the Company, should be recovered through the SMART factor. SMART Order at 150. We see no compelling reason to allow an alternative cost recovery method at this time. As the Company can recover the final allowable costs associated with the IT system enhancements through the SMART factor, denying the proposal in this case does not result in cost disallowance. Finally, in the SMART Order we directed the Company to designate the SMART factor as a separate line item for the purposes of bill clarity and bill transparency. SMART Order at 195. We find that continuing to allow recovery through the

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[164] The Department recognizes and appreciates the Company's resource intensive efforts in providing supporting documentation associated with its SMART Program capital additions (Exhs. ES-ADDITIONS-7 & Supp.; DPU 14-5 (Supp.)).

SMART factor, as opposed to recovering some costs through base distribution rates, maintains the important considerations of bill clarity and transparency.

Based on the above considerations, the Department rejects the Company's proposal to transfer the unrecovered balance of SMART-related IT investments in base distribution rates. As noted above, the Company sought to include $1,908,643 in SMART Program costs in base rates effective January 1, 2023 (Exhs. ES-REVREQ-1, at 22, 41-42; ES-REVREQ-4, Sch. 9 (Rev. 1)). The Company also included in the proposed revenue requirement SMART Program revenues in the amount of $1,893,718 (Exhs. ES-REVREQ-1, at 25; ES-REVREQ-2, Sch. 1, at 9; Sch. 6 (Rev. 4)). The Department removes the SMART Program costs and revenues from the proposed cost of service. The effect of our decision is shown on Schedules 2 and 9 below.

B. Solar Expansion Program Investments

1. Introduction

On June 30, 2016, NSTAR Electric and WMECo filed with the Department a proposal to construct, own, and operate up to 62 MW of solar generation facilities ("Solar Expansion Program") pursuant to G.L. c. 164, § 1A(f). NSTAR Electric Company and Western Massachusetts Electric Company, D.P.U. 16-105 (2016).[165] The Department

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[165] In its initial filing, the Company proposed to move into base distribution rates costs related to its Solar Program approved in D.P.U. 09-05 and Western Massachusetts Electric Company, D.P.U. 13-50 (2013). During the proceeding, the Company acknowledged that it had not conferred with the Attorney General as outlined in D.P.U. 09-05 (Exh. DPU 37-3). As such, the Company withdrew its proposal and made certain adjustments to its proposed cost of service to reflect the removal of these

approved the proposal, which included pre-approval of capital installation and replacement costs, annual operating expenses, and annual lease and property tax expenses. D.P.U. 16-105, at 35-36. In particular, the Department approved a spending cap of $205.7 million on capital installation and replacement costs. D.P.U. 16-105, at 30, 33, 36.

Pursuant to the Company's solar expansion cost recovery mechanism ("SECRM") tariff, as Solar Expansion Program generation facilities are constructed and placed into service, the Company files every six months for adjustments to its solar expansion cost recovery factors ("SECRFs"), beginning on January 1st of each calendar year. The SECRM recovers the investment and ongoing maintenance costs of the solar generation projects, offset by any credits for the sale of energy; either the sales of renewable energy credits ("RECs") into the ISO-NE market or the market value of RECs used to comply with the Renewable Portfolio Standard ("RPS"); and capacity sales, if any (Exh. ES-REVREQ-1, at 34). The SECRFs are reconciled on an annual basis.

2. Company Proposal

The Company reports that it has successfully commissioned the full approved scope of 62 MW approved by the Department in D.P.U. 16-105 (Exh. ES-ADDITIONS-1, at 48). Further, NSTAR Electric states that the Department, through several Solar Expansion Program compliance filings, has reviewed and analyzed the Company's Solar Expansion Program investments and found the costs to be prudent and the facilities used and useful in

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investments from the revenue requirement (Exhs. ES-REVREQ-2, Sch. 1, at 9; Schs. 6, 27, 29-32 (Rev. 4); ES-REVREQ-3, WP 27, at 3 (Rev. 4); DPU 37-3).

providing service to customers (Exh. ES-ADDITIONS-1, at 48, citing NSTAR Electric Company, D.P.U. 19-127-A (2021); NSTAR Electric Company, D.P.U. 19-59-A (2020); NSTAR Electric Company, D.P.U. 18-124-A (2020)). The Company proposes to transfer the Solar Expansion Program capital investments through 2021, totaling $161,594,319, into rate base in this proceeding (Exhs. ES-ADDITIONS-1, at 48; ES-ADDITIONS-12, Att. (b); DPU 37-2).

3. Positions of the Parties

The Attorney General argues that the Department should deny the Company's request to transfer to base distribution rates the costs associated with the Solar Expansion Program, as the costs already are recovered through a reconciling mechanism (Attorney General Brief at 113). We address this argument below. The Attorney General makes several additional arguments, in the context of the proposed PBR plan and annual PBR adjustment, regarding the transfer of the Solar Expansion Program investments to base distribution rates (Attorney General Brief at 113-117, citing Exh. AG-TN-1, at 4-10). The Company raises counter arguments on brief (Company Brief at 52-53). We address these issues in Section IV.D.5.j above.

4. Analysis and Findings

The Department previously determined that the Company acted prudently in undertaking the construction of the Solar Expansion Program facilities and that the facilities were used and useful in providing service to customers prior to the end of the test year.

See D.P.U. 19-127-A at 3, 8; D.P.U. 19-59-A at 4, 12; D.P.U. 18-124-A at 2, 10. Accordingly, we need not review the investments for a prudency or in-service determination.

As noted above, the Company proposes to transfer the Solar Expansion Program capital investments through 2021, totaling $161,594,319, into base distribution rates in this proceeding (Exhs. ES-ADDITIONS-1, at 48; ES-ADDITIONS-12, Att. (b); DPU 37-2). The 2021 capital expenditures were necessary to complete the final close-out activities of the solar facilities that were initiated under the Solar Expansion Program (Exhs. ES-ADDITIONS-1, at 48; ES-ADDITIONS-12, Att. (b); DPU 37-2). These costs include contractor and engineering services, licensing and permitting fees, and other outside services (Exhs. ES-ADDITIONS-12, Att. (b); DPU 37-2). The total 2021 costs also include a refund from National Grid for interconnection costs at one of the solar facilities (Exh. DPU 37-2). As a result, the overall 2021 costs reduce the Company's test-year net plant in service by $793,724 (Exh. DPU 37-2). The Department has reviewed the 2021 costs and supporting documentation, and we find the costs to be reasonable and represent a known and measurable change to the test-year amount. Further, we note that the Company's total capital investment for the Solar Expansion Program is below the spending cap of $205.7 million on capital installation and replacement costs set in D.P.U. 16-105, at 30, 33, 36.

Given that the Solar Expansion Program costs were prudently incurred, the facilities are used and useful in providing service to customers, and the total investment is below the authorized spending cap, we find it reasonable, appropriate, and consistent with precedent to transfer the investments to NSTAR Electric's rate base and allow the Company to recover the unrecovered balance through base distribution rates. See, e.g., D.P.U. 18-150, at 203. Thus, we are not persuaded by the Attorney General's argument to the contrary. Accordingly, the Department allows the Company to transfer the Solar Expansion Program capital investments through 2021, totaling $161,594,319, into base distribution rates in this proceeding.

XV. ADVANCED METERING INFRASTRUCTURE PROPOSALS

A. Introduction

In NSTAR Electric Company, D.P.U. 21-80, NSTAR Electric requested Department approval of its AMI Implementation Plan and submitted for review a model tariff to establish an annual reconciling mechanism to recover costs associated with its plan (Exhs. ES-REVREQ-1, at 200; ES-CAH/DPH-1, at 14, 109-110; ES-AMI-1, at 8, 16-19; DPU 7-1). In the instant proceeding, NSTAR Electric submitted a company-specific rate tariff, proposed M.D.P.U. No. 80, for approval based on the model tariff presented in D.P.U. 21-80 (Exhs. ES-CAH/DPH-1, at 30; ES-AMI-1, at 11, 17; ES-AMI-2; ES-RDC-6, Sch. 1, at 556-561; DPU 7-1). The Company requests that the Department adopt the model tariff for company-specific application and authorize recovery of AMI investment costs after January 1, 2023 (Exh. ES-AMI-1, at 16-17).

As proposed, the company-specific tariff establishes an annual reconciling mechanism and factor allowing NSTAR Electric to recover an annual AMI revenue requirement associated with the Company's AMI-related plant in service for each AMI investment year prior to the recovery year, as well as recoverable O&M expense (Exhs. ES-AMI-1, at 19;

ES-AMI-2; ES-RDC-6, Sch. 1, at 556-561). Specifically, the AMI revenue requirement would be calculated to recover: (1) the monthly revenue requirement for eligible AMI investments recorded as in service in the AMI investment year immediately prior to the recovery year; (2) the average annual revenue requirement for the calendar year ending December 31 of the AMI investment year two years prior to the recovery year, for cumulative eligible investments placed into service in the AMI investment years two years prior to the recovery year; (3) the annual revenue requirement for the recovery year on eligible investments recorded as in service in the AMI investment year immediately prior to the recovery year; and (4) actual monthly AMI-related O&M expenses incurred in the AMI investment year prior to the recovery year (Exhs. ES-REVREQ-1, at 200-201; ES-AMI-1, at 19-20; ES-AMI-2, at 1-5; ES-RDC-6, Sch. 1, at 556-560). The proposed AMIF would apply to all retail delivery service kWh, pursuant to annual Department prudency reviews and approval (Exhs. ES-AMI-1, at 16; ES-AMI-2, at 1, 5-6; ES-RDC-6, Sch. 1, at 560-561). As contemplated in the proposed tariff, NSTAR Electric would submit to the Department an annual AMI cost recovery filing by May 15 that would include the following: (1) project documentation of all eligible AMI investment recorded as in service by the Company during the prior AMI investment year; (2) documentation supporting non-recurring O&M expense as part of recoverable O&M expense; (3) the AMI reconciliation calculation; and (4) bill impacts (Exhs. ES-REVREQ-1, at 201; ES-AMI-1, at 20; ES-AMI-2, at 5-6; ES-RDC-6, Sch. 1, at 560-561). Pursuant to Department review and approval, the AMIF would be in effect from July 1 to June 30 of each year (Exhs. ES-AMI-2, at 1, 4-5; ES-RDC-6, Sch. 1, at 559-560).

As part of the Company's AMI Implementation Plan, NSTAR Electric has proposed an increase in the depreciation accrual rate for Account 370.10 (Meters – AMR). As discussed in more detail in Section VII.B.1 above, the Company's proposed depreciation rate of 8.62 percent is intended to align with the planned deployment of AMI and retirement of AMR meters by 2028 (Exhs. ES-REVREQ-1, at 202-203; ES-AMI-1, at 21). Because AMR meters will continue to be purchased and installed prior to AMI implementation, NSTAR Electric proposes to treat any remaining undepreciated plant associated with AMR meters at the time of full AMI implementation as a regulatory asset (Exhs. ES-REVREQ-1, at 203-204; ES-AMI-1, at 21-22). Under the Company's proposal, the amortization for the regulatory asset would be based on the period of recovery of investment through depreciation of AMR meters approved in the instant proceeding (Exhs. ES-REVREQ-1, at 204; ES-AMI-1, at 22). NSTAR Electric proposed that after the regulatory asset is fully amortized, the Company would apply the amount of depreciation in base distribution rates against the recovery of the AMI cost recovery mechanism (Exhs. ES-REVREQ-1, at 204; ES-AMI-1, at 22).

NSTAR Electric also proposed to establish a cost-of-service benchmark for metering infrastructure to determine incremental O&M expense related to AMI (Exh. REVREQ-1, at 202-203, 205-209). In particular, the Company proposed to measure incremental costs based on the test-year level of costs for meter expenses, maintenance of meters, meter reading expenses, and miscellaneous customer accounts expenses as measured by the FERC

Account (Exh. ES-REVREQ-1, at 205-206). Using FERC Accounts 586, 597, 902, and 905, the Company calculated $9.7 million in test-year metering costs (Exhs. ES-REVREQ-1, at 206; ES-AMI-1, at 24; ES-AMI-3, at 1). This amount represents the baseline amount the Company proposed to compare against to determine incremental cost recovery for AMI meter-related O&M (Exhs. ES-REVREQ-1, at 206; ES-AMI-1, at 24). NSTAR Electric proposed to track and provide documentation for the O&M costs incurred related to AMI implementation, and to recover as incremental costs the lesser of these costs or the net change to FERC Accounts 586, 597, 902, and 905 from the test-year amount of $9.7 million, adjusted each year for the annual change in GDP-PI (Exhs. ES-REVREQ-1, at 206-207; ES-AMI-1, at 24-25).

B. Positions of the Parties

1. Attorney General

The Attorney General argues that the Department should deny any new capital tracker cost recovery mechanism proposed by NSTAR Electric (Attorney General Brief at 39, 55).[166] The Attorney General contends that the annual rate increases contemplated by the proposed PBR plan will provide recovery for all costs of providing electric distribution service, and that the recovery mechanisms will overcompensate the Company for costs related to AMI and customer information systems ("CIS") investments (Attorney General Brief at 39). As an

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[166] TEC and PowerOptions also argue the Department should decline to adopt new capital trackers, including one for AMI costs, beyond the scope of the grid modernization proceedings (TEC/PowerOptions Brief at 14).

alternative, and as discussed in further detail in Section IV.C.1 above, the Attorney General recommends establishing an all-in capital tracker in lieu of a PBR plan, and she argues it would obviate the need for the Company's AMI cost recovery proposals here and in D.P.U. 21-80 (Attorney General Brief at 43). Under this scenario, the Attorney General indicates that the all-in capital tracker would allow for recovery of all NSTAR-specific investments (Attorney General Brief at 43).

The Attorney General maintains that if the Department rejects the proposed all-in tracker recommendation, it should still reject or modify the Company's AMI-related proposal (Attorney General Brief at 44). On brief, the Attorney General reiterates the arguments she presented in D.P.U. 21-80 (Attorney General Brief at 44-51). First, the Attorney General contends that AMI capability is not a special investment that requires exceptional recovery outside of base distribution rates, but instead should be treated as business as usual and accounted for in the proposed PBR plan and rate formula increases to base distribution rates (Attorney General Brief at 44-49, citing Exhs. AG-TN-1, at 12-13; AG-TN-2, at 2-14).

Additionally, the Attorney General claims that the proposed company-specific AMI tariff has the same issues she identified in the model AMI tariff submitted in D.P.U. 21-80 (Attorney General Brief at 49). Specifically, the Attorney General contends the proposed tariff has the following flaws: (1) the AMI revenue requirement in Section 2.7 does not recognize, nor does it "net out" recovery of the meter system cost recovery that already exists in base distribution rates; (2) the AMI revenue requirement in Section 2.7, parts (1) and (3) provide double recovery of the costs of plant placed in service during the investment year; (3) the eligible investment in Section 2.10 should recognize and adjust for the meter investment, whether "in service" or in the warehouse inventory, of newer AMR or bridge meters than can be repurposed for those customers who opt-out of AMI; (4) the tariff makes no provision for the reduction in O&M expense related to embedded meter investment or otherwise that any new capital investment creates; (5) the recoverable O&M expense charged from the service company in Section 2.16 should reflect only the appropriate and reasonable allocated share of any such service company costs, and not any amount that is "charged;" (6) the property tax rate definition in Section 2.14 should reflect the total utility property tax paid for the year as a percentage of the total utility property valuation for that same tax year and not the net plant; (7) there is no indication that the tariffed charge provides for a fully reconciling charge; (8) there is no definition of the term "incremental" that is it is used in Sections 1.0 and 2.16; (9) there is no provision for reconciliation or incorporation of the costs recovered through the charge with those recovered through base distribution rates; and (10) there is no provision for termination of the tariff (Attorney General Brief at 49-50, citing Exhs. ES-AMI-2; AG-TN-2, at 14-16). To the extent that the Department approves the Company's proposed tariff, the Attorney General argues that the necessary changes should be made to correct these flaws (Attorney General Brief at 50). Consistent with the recommendations made in D.P.U. 21-80, the Attorney General also requests the AMI cost recovery tariff be amended such that NSTAR Electric can only earn a return on its grid modernization investments after it shows that it has actually achieved and delivered to ratepayers the benefits the Company projected in its benefit cost analysis (Attorney General Brief at 50-51).

Regarding the Company's proposal to track and document incremental O&M costs and savings, the Attorney General argues it is inadequate for two reasons: (1) the use of actual savings does not hold the Company accountable for delivering benefits of the same magnitude and within the timeframes that its business case projects; and (2) the proposal leaves other rate-case-dependent benefits quantified in the AMI business case, including reductions in bad-debt expense and truck rolls from "no trouble found" incidents unaccounted for (Attorney General Brief at 53-54). As she recommends in D.P.U. 21-80, the Attorney General requests that the Department reduce the Company's AMI cost recovery revenue requirement by the amount of O&M savings and revenue assurance benefits projected in the benefit cost analysis until the actual cost reductions are fully captured and reflected in a subsequent base distribution rate case (Attorney General Brief at 54).

Finally, the Attorney General argues that the proposed company-specific tariff should be amended to reflect net cost reductions back to ratepayers if the Company receives government funding (Attorney General Brief at 54). Because the Company asks for timely approval of its AMI plan and cost recovery proposal to increase its likelihood of obtaining Infrastructure Investment and Jobs Act ("2021 IIJA")[167] funding, the Attorney General claims that there should be a mechanism to flow back to ratepayers any 2021 IIJA funding, or any

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[167] Infrastructure Investment and Jobs Act of 2021, Pub. L. 117-58.

other federal or state funding, for the Company's AMI system investments (Attorney General Brief at 54-55). Therefore, she argues the proposed tariff must include a provision to ensure ratepayers realize the benefits of government funding immediately (Attorney General Brief at 55).

2. Company

NSTAR Electric asserts its narrow proposal in the instant proceeding is to obtain Department approval of the company-specific AMI tariff, which follows from the model AMI tariff submitted in D.P.U. 21-80 (Company Brief at 371, citing Exh. DPU 7-1). The Company maintains that approval of the proposed tariff is the next step in establishing the platform to support the Company's AMI Implementation Plan (Company Brief at 371-372, citing Exhs. ES-AMI-1, at 8; DPU 7-1). NSTAR Electric asserts that under the proposal all AMI capital additions will be subject to a prudence review as the costs are proposed for recovery through the reconciling mechanism (Company Brief at 372, citing Exh. ES-AMI-1, at 16). The Company contends that it has proposed an end-of-life meter replacement plan that is consistent with the directives in Modernization of the Electric Grid – Phase II, D.P.U. 20-69-A (2021), including its proposal to treat any remaining book value associated with AMR at the time of full AMI implementation as a regulatory asset (Company Brief at 372, citing Exh. ES-REVREQ-1, at 204).

In response to the Attorney General, the Company argues that she simply restates her recommendations from D.P.U. 21-80, and that all the claims, arguments, and recommendations there were thoroughly rebutted (Company Brief at 372).[168] In particular, NSTAR Electric maintains that the Attorney General's arguments are based on flawed concepts and mischaracterizations of the Company's AMI Implementation Plan and proposed cost recovery mechanism (Company Brief at 374).

C. Analysis and Findings

1. Introduction

NSTAR Electric requested approval of its AMI Implementation Plan and model AMI tariff in D.P.U. 21-80 (Exhs. ES-REVREQ-1, at 200; ES-CAH/DPH-1, at 14, 109-110; ES-AMI-1, at 8, 16-19; DPU 7-1). In the instant proceeding, the Company seeks approval of the company-specific tariff that follows from, and is identical to, the model AMI tariff, but has been identified as company-specific (Exhs. ES-CAH/DPH-1, at 30; ES-AMI-1, at 11, 17; ES-AMI-2; ES-RDC-6, Sch. 1, at 556-561; DPU 7-1). Additionally, the Company proposes to recover any remaining book value of AMR meter costs at the time of AMI implementation through the establishment of a regulatory asset, and to establish a cost-of-service baseline for incremental O&M expense associated with AMI implementation (Exhs. ES-REVREQ-1, at 202-209; ES-AMI-1, at 20-22; ES-AMI-3). Concurrent with the instant Order, the Department approves NSTAR Electric's AMI Implementation Plan and a

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[168] NSTAR Electric does not reiterate all of its positions in its brief, but notes that the Company's response to the Attorney General's contentions and recommendations can be found in pages 61 through 111 of the Company's initial brief filed on June 1, 2022, in D.P.U. 21-80, and pages three through 23 of the Company's reply brief filed on June 28, 2022, in the same docket (Company Brief at 374).

new AMIF reconciling mechanism, as well as directs modifications to the proposed model AMI tariff. D.P.U. 21-80-B/D.P.U. 21-81-B/D.P.U. 21-82-B at 234, 238-239, 285-306. Because the only update to the model AMI tariff in the instant proceeding is the identification as company-specific, the Department adopts the findings from D.P.U. 21-80-B/D.P.U. 21-81-B/ D.P.U. 21-82-B and will not re-examine the arguments addressed therein.

2. AMR and Legacy Assets

As part of the Company's proposal, NSTAR Electric seeks approval to treat any remaining book value of AMR meter costs at the time of AMI implementation as a regulatory asset (Exhs. ES-REVREQ-1, at 204; ES-AMI-1, at 22; DPU 7-1; DPU 16-8; DPU 33-3, at 3; DPU 42-12). While the amount of remaining AMR meter costs at the time of AMI implementation is uncertain, the Company estimates a potential unrecovered AMR meter balance of approximately \$21 million to \$23 million at the end of 2028 (Exhs. DPU 9-1, at 2 & Att. (b); DPU 33-3, at 2 & Att. (b)).[169]

A regulatory asset is an incurred cost for which a regulatory agency such as the Department allows a regulated company to record a deferral to be considered for recovery in the future. Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 10-54, at 318 n.235 (2010). See Bay State Gas Company, D.P.U. 15-50, at 6 n.10 (2015). A regulatory asset is created when regulators provide reasonable assurance of the

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[169] The Company also suggested in testimony an unrecovered AMR balance upwards of \$40 million at the end of AMI deployment (Exh. ES-AMI-1, at 22).

creation of an asset, i.e., when a company capitalizes all or part of an incurred cost that would otherwise be expensed and the regulators allow recovery of revenue at least equal to that cost. Western Massachusetts Electric Company, D.P.U. 94-8-CC (Phase I) at 12 n.13 (1994). NSTAR Electric does not seek to defer an incurred cost to be considered for future recovery, but instead essentially seeks approval to create and recover a potential regulatory asset with an amortization period determined by the amount of depreciation expense associated with AMR meters set in this proceeding (Exhs. ES-REVREQ-1, at 204; ES-AMI-1, at 22; DPU 9-1, Att. (b); DPU 16-8; DPU 42-11). Under the Company's proposal, once the regulatory asset is fully amortized, the amortization amount, equal to depreciation expense associated with AMR meters in base distribution rates, would be applied against the recovery of AMI costs in the recovery mechanism (Exhs. ES-REVREQ-1, at 204; ES-AMI-1, at 22; DPU 42-11). The Company's proposal therefore is for current approval for recovery of an unknown amount and amortization period.

While not included in NSTAR Electric's initial proposal, the Company suggests that to the extent that any similarly unrecovered costs related to legacy CIS and meter data management systems ("MDMS") remain, these costs would be treated as a regulatory asset in the same manner (Exh. DPU 46-3). The Company's CIS associated with WMA and EMA service areas were launched in 2008 and 1990, respectively, and have both been fully depreciated (Exh. DPU 9-2).[170] The Company notes, however, that it has made periodic

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[170] While the Company could not identify the original book value of the CIS launched in 1990, software is typically depreciated over a period of three to ten years, and therefore all software installed by NSTAR Electric and ESC prior to 2010 has been

additional capital investments over time after the initial installations to address business needs and regulatory requirements and may need to make additional investments between today and the time AMI systems are fully installed (Exh. DPU 9-2). As such, any unrecovered costs or necessary retirements would be treated similarly to how the Company proposes to treat unrecovered AMI costs (Exhs. DPU 9-2; DPU 46-3). With respect to the Company's MDMS, NSTAR Electric anticipates the costs will be fully recovered in 2023 and 2027, but to the extent unrecovered costs remain they would be dealt with similarly (Exh. DPU 46-3).

The Department permits companies to establish regulatory assets in limited circumstances. D.P.U. 10-55, at 311. In this instance the Company's proposal is inconsistent with Department precedent because it seeks approval of cost recovery for potential, currently unknown, costs and a yet to be determined amortization schedule. Moreover, the Department has concerns regarding the potential for double recovery and overcollection of costs associated with the transition from AMR to AMI (Exh. DPU 9-1). During the proceeding, the Department explored the potential for under- or over-recovery of costs related to AMR and AMI implementation, as well as the Company's willingness to recover all AMR, AMI, CIS, and MDMS costs, <u>i.e.</u>, meter-related capital, through the AMIF beginning on January 1, 2023 (Exhs. DPU 9-1; DPU 33-3; DPU 42-8; DPU 43-1; DPU 46-3; Tr. 7, at 713-718; RR-DPU-29). In evidentiary hearings as well as in response to discovery, the Company confirmed that it would not object to recovering all meter-related

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fully depreciated; the original book value of the 2008 CIS was $9,612,342 and has been fully depreciated (Exhs. DPU 9-2; DPU 46-7).

capital through the AMIF, and that such treatment would eliminate the potential for over-recovery of costs, the need to establish any regulatory assets, and the need to recognize any offsets in the reconciling mechanism to coordinate between amounts still being recovered in base distribution rates (Exhs. DPU 43-1; DPU 46-3; Tr. 7, at 714-717; RR-DPU-29; RR-DPU-33). Based on these benefits, as well as the administrative efficiency of reviewing and recovering related costs through a single mechanism, the Department directs the Company to remove from base distribution rates all meter-related capital, and to instead recover them through the proposed reconciling mechanism. Accordingly, the Department directs the Company to reduce plant in service associated with Account 370 in the amount of $328,863,241, as well as the associated accumulated depreciation of $120,017,193 and ADIT in the amount of $50,123,051 (Exh. ES-REVREQ-3, WPs 25, 31 (Rev. 4); RR-DPU-29, Att. (e) at 1). An additional reduction is also required to O&M expense in the amount of $1,696,500[171] associated with the Company's legacy CIS and MDMS, and a reduction of $5,919,880 in property taxes (RR-DPU-29, Att. (a); RR-DPU-33).

3. Incremental O&M Baseline

NSTAR Electric calculates a test-year cost for metering and miscellaneous customer account expenses of $9.7 million, based on costs from FERC Accounts 586, 597, 902, and 905 (Exhs. ES-REVREQ-1, at 206; ES-AMI-1, at 24; ES-AMI-3, at 1; DPU 45-1). This

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[171] The Company identified $1,712,485 as the annual recovery amount based on its proposed ROE (RR-DPU-29, Atts. (c) & (d)). This amount has been revised using the ROE approved by the Department in this Order and in accordance with the calculations applied to Enterprise IT expenses, discussed in Section VII.G.4 above.

amount represents the baseline amount of meter-related expenses NSTAR Electric will compare against in order to determine incremental cost recovery for AMI-meter related O&M as a component of the Company's reconciling mechanism (Exhs. ES-REVREQ-1, at 206; ES-AMI-1, at 24; ES-AMI-3, at 1). The Company proposes to track and document O&M costs required for AMI implementation and to recover as incremental costs the lesser of these costs or the net change to FERC Accounts 586, 597, 902, and 905 from the test amount of $9.7 million, adjusted each year for the annual change in GDP-PI (Exhs. ES-REVREQ-1, at 207; ES-AMI-1, at 24-25; DPU 45-2). NSTAR Electric acknowledges that there will be incremental O&M savings as well as costs and proposes to offset its requested incremental cost recovery by any AMI-related costs savings realized in the deployment of AMI (Exhs. ES-REVREQ-1, at 206-209; ES-AMI-1, at 25-26; ES-AMI-3, at 2). The Department has reviewed the identified categories and estimates of potential incremental costs and savings and finds that they are based on reasonable assumptions (Exhs. ES-REVREQ-1, at 207-209; ES-AMI-1, at 25-26; ES-AMI-3, at 2; DPU 45-1). Further, the Department finds that the Company's proposal for tracking incremental costs and savings ensures it will not double recover AMI related costs while appropriately accounting for inflation and potential savings (Exhs. ES-REVREQ-1, at 205-209; ES-AMI-1, at 25-26; ES-AMI-3, at 2; DPU 45-1; DPU 45-2). Therefore, the Department approves the Company's proposal for an incremental O&M expense baseline of $9.7 million, adjusted each year only for the annual change in GDP-PI, and directs NSTAR Electric to also account for actual AMI-related O&M savings as part of its reconciling mechanism filing.

4. Conclusion

Consistent with the Department's approval of NSTAR Electric's AMI Implementation Plan and AMI reconciling mechanism in D.P.U. 21-80-B/D.P.U. 21-81-B/D.P.U. 21-82-B, the Department approves the proposed company-specific AMI tariff, subject to the findings and modifications above and in D.P.U. 21-80-B/D.P.U. 21-81-B/ D.P.U. 21-82-B. Moving meter-related capital from base distribution rates to the Company's reconciling mechanism approved in D.P.U. 21-80-B/D.P.U. 21-81-B/ D.P.U. 21-82-B results in approximately $48.9 million being recovered through the AMIF effective January 1, 2023.[172] As designed, the AMIF will normally go into effect annually on July 1, and is intended to be in effect for a 12-month period through June 30 of the following year, but because the Department directs the Company to move all meter-related capital to the reconciling mechanism, the initial rate will go into effect January 1, 2023, to coincide with the establishment of new base distribution rates (RR-DPU-29). On May 15, 2024, the Company will file its annual AMIF to reconcile the revenue requirement associated with meters and existing CIS and MDMS systems for investment through December 31, 2023, including eligible AMI investments potentially incurred in 2022 (RR-DPU-29). D.P.U. 21-80-B/D.P.U. 21-81-B/D.P.U. 21-82-B at 238 & n.95. As part of NSTAR Electric's compliance filing in the instant proceeding, the Department directs the Company to file an updated AMI tariff that is

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[172] The Company identified $50,153,098 as the annual recovery amount based on its proposed ROE (RR-DPU-29, at 2 n.1). This amount has been revised using the ROE approved by the Department in this Order.

consistent with the Department's findings both herein and in D.P.U. 21-80-B/D.P.U. 21-81-B/D.P.U. 21-82-B.

XVI. CAPITAL STRUCTURE AND COST OF CAPITAL

A. Introduction

NSTAR Electric proposes a 7.43-percent WACC representing the rate of return to be applied on rate base to determine the Company's total return on its investment (Exh. ES-REVREQ-2, Sch. 1, at 5, Sch. 33, at 1 (Rev. 4)). The Company's WACC comprises the following elements: (1) a capital structure consisting of 46.34 percent long-term debt, 0.45 percent preferred stock, and 53.21 percent common equity; (2) a long-term debt cost rate of 3.93 percent; (3) a preferred stock cost of 4.56 percent; and (4) an ROE of 10.50 percent (Exh. ES-REVREQ-2, Sch. 1, at 5 (Rev. 4)). The Attorney General proposes a 6.28-percent WACC based on the following components: (1) a capital structure consisting of 49.47 percent long-term debt, 0.53 percent preferred stock and 50.00 percent common equity; (2) a long-term debt cost rate of 3.60 percent; (3) a preferred stock cost of 4.56 percent; and (3) an ROE of 8.95 percent (Exhs. AG-JRW-1, at 5; AG-JRW-Surrebuttal-1, at 8).

B. Capital Structure

1. Introduction

At the end of the test year, NSTAR Electric reported a $3,670,000,000 long-term debt balance, a $43,000,000 preferred stock balance, and a $4,521,109,220 in common equity balance (Exh. ES-REVREQ-2, Sch. 33, at 1 (Rev. 4)). The Company proposes:

(1) an increase of $800,000,000 to its long-term debt balance to reflect $1,450,000,000 in long-term debt issuances in 2021 and 2022[173] less the redemption of $650,000,000 in long-term debt issuances that reached maturity in 2021 and 2022; and (2) an increase of $612,000,000 to its common equity balance to reflect post test-year equity contributions from its parent company (Exh. ES-REVREQ-2, Sch. 33 (Rev. 4)). NSTAR Electric's adjustments result in a capitalization ratio of 46.34 long-term debt, 0.45 percent preferred stock, and 53.21 percent common equity (Exh. ES-REVREQ-2, Sch. 33, at 1 (Rev. 4)).

The Attorney General proposes an imputed capital structure of 49.47 precent long-term debt, 0.53 percent preferred stock, and 50.00 percent common equity (Exhs. AG-JRW-1, at 31; JRW-4). The Attorney General states that an imputed capital structure aligns the Company with the capital structures of its parent company and the companies in the proxy groups (Exhs. AG-JRW-1, at 30-31; AG-JRW-Surrebuttal-1, at 7).

2. Positions of the Parties

a. Attorney General

The Attorney General contends that NSTAR Electric's common equity ratio is higher than the average common equity ratios of the proxy groups of electric companies compiled by the Company and the Attorney General (see Sections XVI.D.1.a and Section XVI.D.1.b below) and higher than Eversource Energy's common equity ratio (Attorney General Brief

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[173] On March 31, 2021, the Department authorized the Company to issue long-term debt securities in an amount not to exceed $1,600,000,000. NSTAR Electric Company, D.P.U. 20-146, at 27 (2021).

at 81, 84). The Attorney General claims that the Company is benefiting from "double leverage" because the parent company has a higher debt ratio than NSTAR Electric (Attorney General Reply Brief at 15). She argues that the solution to double leverage is to impute a more reasonable capital structure for the revenue requirement calculation or to recognize the downward impact that an unusually high equity ratio will have on the financial risk of a utility (Attorney General Reply Brief at 16-17).

b. Company

The Company argues that its proposed common equity ratio is similar to common equity ratios recently approved by the Department (Company Brief at 252-253, citing, e.g., Exh. ES-VVR-Rebuttal-1, at 103-104; D.P.U. 17-05, at 623 (53.54 percent common equity)). Moreover, NSTAR Electric maintains that the Company's proposed common equity ratio is comparable to that of the average common equity ratio of the Company's proposed proxy group of electric companies, which was 54.80 percent (Company Brief at 253, citing Exh. ES-VVR-Rebuttal-1, at 101-102).

3. Analysis and Findings

A company's capital structure typically consists of long-term debt, preferred stock, and common equity. D.P.U. 07-71, at 122; D.T.E. 03-40, at 319; D.T.E. 01-56, at 97; Pinehills Water Company, D.T.E. 01-42, at 17-18 (2001). The ratio of each capital structure component to the total capital structure is used to weight the cost (or return) of each capital structure component to derive a WACC. D.P.U. 07-71, at 122; D.T.E. 03-40, at 319; D.T.E. 01-42, at 18; D.P.U. 86-149, at 5. The WACC is used to calculate the rate of return, which is applied to a company's rate base as part of the revenue requirement established by the Department, and it is made up of three components: (1) the cost of a company's long-term debt; (2) the cost of a company's preferred stock; and (3) the ROE set by the Department. D.P.U. 07-71, at 122; D.T.E. 03-40, at 319; D.T.E. 01-42, at 18; D.P.U. 86-149, at 5.

The Department typically will accept a company's test-year-end capital structure, allowing for known and measurable changes. D.T.E. 03-40, at 323-324; Boston Gas Company, D.P.U. 88-67 (Phase I) at 74 (1988); D.P.U. 84-94, at 50. Within a broad range, the Department will defer to the management of a utility in decisions regarding the appropriate capital structure, unless the capital structure deviates substantially from sound utility practice. Mystic Valley Gas Company v. Department of Public Utilities, 359 Mass. 420, 428-429 (1971); High Wood Water Company, D.P.U. 1360, at 26-27 (1983); Blackstone Gas Company, D.P.U. 1135, at 4 (1982) (a company's capital structure that is composed entirely of common equity with no long-term debt varies substantially from usual utility practice); see also Cambridge Electric Light Company, D.P.U. 20104, at 42 (1979).

As noted above, NSTAR Electric proposes to increase its test-year balance of long-term debt by $800,000,000 (Exhs. ES-REVREQ-1, at 144; ES-REVREQ-2, Sch. 33, at 1 (Rev. 4); DPU 10-1; Tr. 7, at 730-734). D.P.U. 20-146, Compliance Filing, Att. D (June 1, 2021); D.P.U. 20-146, Compliance Filing, Att. D (August 25, 2021); D.P.U. 20-146, Compliance Filing, Att. D (May 23, 2022); D.P.U. 20-146, Compliance

Filing, Att. D (September 16, 2022)). The Department finds that the Company's $800,000,000 long-term debt adjustment is a known and measurable change and accepts the Company's pro forma long-term debt balance of $4,470,000,000 (Exh. ES-REVREQ-2, Sch. 33 (Rev. 4)).

Turning to the Company's pro forma common equity balance, the Company proposes an increase of $612,000,000 to its test-year-end balance of common equity to reflect post-test-year capital contributions from Eversource Energy (Exhs. ES-REVREQ-2, Sch. 33, at 1 (Rev. 4); DPU 10-2; Tr. 7, at 744). While the Department accepts known and measurable changes to test-year-end capitalization, we examine parent holding company capital contributions for potential adverse rate effects because capital contributions are not subject to regulatory review under G.L. c. 164, § 14. D.P.U. 15-80/D.P.U. 15-81, at 252-253; D.P.U. 14-150, at 317 n.197; D.P.U. 10-70, at 241-242. NSTAR Electric has demonstrated that the post-test-year capital contributions from Eversource Energy are known and measurable and that the capital contributions were necessary for the Company to maintain its financial metrics and credit rating (Exh. AG 1-11, Att. (d) at 7 (Supp.); Tr. 7, at 742-744). Therefore, the Department accepts the Company's pro form common equity balance of $5,133,109,220 (Exh. ES-REVREQ-2, Sch. 33, at 1 (Rev. 4)).

In support of her contention that the Company's proposed common equity ratio should be rejected, the Attorney General has neither argued nor presented evidence demonstrating that the Company's common equity ratio of 53.21 percent deviates substantially from sound utility practice. Rather, the Attorney General bases her position solely on her consultant's testimony that the Department must recognize that the Company's higher equity ratio reduces its financial risk by calculating its cost of capital using an imputed capital structure or authorizing a lower ROE (Attorney General at 84, citing Exh. AG-JRW-1, at 25-30). The consultant's contention alone does not meet the Department's standard to impute a capital structure. The Company's common equity ratio is consistent with those approved by the Department in recent years, and we do not conclude that such a ratio is so weighted towards equity as to deviate substantially from sound utility practice or impose an unfair burden on consumers. D.P.U. 20-120, at 382 (approving a 53.44-percent common equity ratio and rejecting the Attorney General's imputed capital structure); D.P.U. 19-120, at 344-346 (approving a 54.77-percent common equity ratio and rejecting the Attorney General's imputed capital structure); D.P.U. 18-150, at 450 & n.231 (approving a 53.49-percent common equity ratio and rejecting the Attorney General's imputed capital structure); D.P.U. 17-05, at 623 (approving 53.91-percent and 54.51-percent common equity ratios and rejecting the Attorney General's imputed capital structures). Therefore, the Department will use a long-term debt balance of $4,470,000,000, a preferred stock balance of $43,000,000, and a common equity balance of $5,133,109,220 to determine NSTAR Electric's capital structure and cost of capital. The Department addresses the Company's financial risk compared to the proxy companies in Section XVI.D.3.g below.

C. Cost of Debt

1. Introduction

In its initial filing, the Company calculated a cost of debt of 3.60 percent (Exh. ES-REVREQ-2, Sch. 33, at 2). Based on the updates to its long-term debt balance discussed above, the Company proposes a long-term debt cost of 3.93 percent, which is calculated by dividing the annual interest payments by the principal amount of the issuances outstanding (Exh. ES-REVREQ-2, Schedule 33, at 2 (Rev. 4)). The Attorney General did not address the Company's updated cost of debt on brief.

2. Analysis and Findings

The Department has reviewed the Company's calculation of its proposed 3.93-percent cost of debt and determines that the cost of debt was properly calculated (Exh. ES-REVREQ-2, Sch. 33, at 2 (Rev. 4)). Therefore, the Department accepts the use of a 3.93-percent cost of debt for the purpose of determining the Company's WACC.

D. Return on Equity

1. Introduction

a. Company's Proposal

The Company's proposes a 10.50-percent ROE based on an analysis that considered the results of the constant growth discounted cash flow model ("DCF") and two risk premium models: (1) the capital asset pricing model ("CAPM"); and (2) the bond yield plus risk premium model ("RPM") (Exh. ES-VVR-1, at 5-6). These models are applied to the market data and financial information of two proxy groups of publicly-held companies

(Exh. ES-VVR-1, at 30-34).[174] The first proxy group comprises 15 publicly traded utility companies engaged in the business of electric distribution service ("Electric Proxy Group"),[175] and the second proxy group comprises twelve publicly-traded domestic companies with investment risk profiles that the Company represents are equivalent or lower than the Electric Proxy Group ("Non-Regulated Proxy Group") (Exh. ES-VVR-1, at 30-34).[176] In addition, NSTAR Electric's ROE analysis also considers the following factors to propose an ROE within the range of analytical results: (1) current and projected capital market conditions; (2) qualitative factors; and (3) the Company's proposed PBR plan (Exhs. ES-VVR-1, at 22, 37, 40; ES-CAH/DPH-1, at 110-117).

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[174] It is necessary to establish a group of publicly traded companies to serve as a proxy to estimate a market-based ROE because the Company is a wholly owned subsidiary of Eversource Energy and is not publicly traded (Exh. ES-VVR-1, at 21).

[175] The following were NSTAR Electric's selection criteria for the Electric Proxy Group: (1) an electric utility; (2) a safety rank of one, two, or three; (3) a corporate credit rating of at least BBB- or Baa3; (4) currently paying dividends without having discontinued or reduced dividends over the previous five years (2016-2020); (5) does not own nuclear power generation facilities; and (6) is not and has not recently been an acquisition target (Exh. ES-VVR-1, at 31).

[176] The following were NSTAR Electric's selection criteria for the Non-Regulated Proxy Group: (1) a conservative stock classification, meaning a safety rank no lower than one (2) a beta between 0.75 and 0.95; (3) a financial strength rating of A+ or higher; (4) a corporate credit rating of at least BBB- or Baa3; (5) not in the following businesses: gas and/or electric distribution, investment and financial services, pharmaceutical, life sciences, medical technology, hardware/software, or defense contracting; (6) currently paying dividends without having discontinued or reduced dividends over the previous five years (2016-2020); and (7) having at least one consensus earnings estimate published by an information service (Exh. ES-VVR-1, at 35).

In NSTAR Electric's DCF analyses, the required ROE equals the sum of the expected dividend yield and the expected long-term growth rate (Exh. ES-VVR-1, App. A). For the expected dividend yield, the Company uses the proxy companies' current annualized dividend and 30-day, 60-day, and 90-day average closing stock prices (Exhs. ES-VVR-1, App. A at 1; ES-VVR-3, at 3; ES-VVR-4, at 3). For the expected long-term growth rate, the Company uses projected earnings per share ("EPS") growth rates of the proxy companies provided by Thomson First Call (provided by Yahoo! Finance), Zacks Investment Research, and Value Line Investment Survey ("Value Line"), along with historical EPS growth rates provided by Value Line (Exhs. ES-VVR-1, at 48; ES-VVR-1, App. A at 5; ES-VVR-3, at 2; ES-VVR-4). The Company states that it excludes low-end and high-end outliers from its calculation of the mean DCF results to remove low cost of equity estimates that investors would not reasonably accept over corporate debt securities and high cost of equity estimates that reflect earnings growth that are not likely sustainable for regulated utility companies (Exhs. ES-VVR-1, at 7 & App. B, at 5; ES-VVR-3). In addition, the Company adjusts the model results to account for flotation costs[177] and includes a financial risk adjustment based on the difference between the market value and book value of the companies ("leverage adjustment") (Exhs. ES-VVR-1, at 48; ES-VVR-1, App. C; ES-VVR-1 App. D). After these adjustments,

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[177] Flotation costs are the costs incurred in issuing securities, also referred to as issuance costs. D.P.U. 85-266-A/85-271-A at 169; D.P.U. 19-120, at 354 n.172.

the Company's updated, mean DCF results are 9.68 percent for the Electric Proxy Group and 11.85 percent for the Non-Regulated Proxy Group (Exh. ES-VVR-Rebuttal-2, at 1, 2).[178]

The Company's CAPM includes three components to calculate the cost of equity: (1) a risk-free rate of return; (2) the proxy companies' beta coefficients, which are measures of systemic risk;[179] and (3) a market risk premium, which is the difference between market return estimates and the risk-free rate of return (Exh. ES-VVR-1, at 51). For the risk-free rate of return, NSTAR Electric uses average projected 30-year U.S. Treasury Bond yields from Blue Chip Financial Forecasts (Exhs. ES-VVR-1, at 55; ES-VVR-5, at 1; ES-VVR-Rebuttal-5, at 1).

The Company uses beta coefficients for the proxy companies published by Value Line with a leverage adjustment, which the Company states is necessary to reflect the difference between the companies' book value capital structure and market value capital structure (Exh. ES-VVR-1, at 60-61). NSTAR Electric's estimated market-return comprises a one-quarter weighting of a DCF analysis on the Standard and Poor's ("S&P") 500 Index, a one-quarter weighting of a DCF analysis on the Value Line 1,700 Stock Universe, and a one-half weighting of the historical Ibbotson Stocks, Bonds, Bills, and Inflation Yearbook annual total returns from 1926 to 2020 (Exhs. VVR-5, at 1-2; ES-VVR-Rebuttal-5, at 1-2).

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[178] In the Company's initial filing, the adjusted, mean DCF results were 9.78 percent and 11.70 percent, respectively (Exh. ES-VVR-1, at 78).

[179] A stock's beta measures the co-variability between the price movements of an individual stock and the price movements of the total market portfolio (Exh. ES-VVR-1, at 52).

In addition to the traditional CAPM results, the Company considers the CAPM results with a size adjustment published by Duff & Phelps and the results of the empirical CAPM, which applies a 75-percent weighting to the product of the beta coefficient and the market risk premium and a 25-percent weighting to the market risk premium alone (Exh. ES-VVR-1, at 63-66). For the Electric Proxy Group, after applying an adjustment for flotation costs, the Company's updated traditional, size adjusted, and empirical CAPM results range from 11.39 percent to 11.88 percent (Exh. ES-VVR-Rebuttal-2, at 3).[180] For the Non-Regulated Proxy Group, after applying an adjustment for flotation costs, the Company's traditional, size adjusted, and empirical CAPM results range from 10.95 percent to 11.25 percent (Exh. ES-VVR-Rebuttal-2, at 3).[181]

In NSTAR Electric's RPM, the cost of equity equals the sum of the Company's prospective cost of debt and expected equity risk premium (Exh. ES-VVR-1, at 67-68). For the Electric Proxy Group, the Company uses an average of equity risk premiums, including: (1) historic returns for the S&P 500 Composite Index less historic long-term corporate bonds; (2) the prospective equity risk premium used in the CAPM described above; (3) historic returns for the S&P Utilities Index less historic utility bond yields; and (4) a DCF analysis of the S&P 500 Utilities Index less the three-month average of Moody's Investors Service Inc.'s

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[180] In NSTAR Electric's initial filing, the Electric Proxy Group CAPM results ranged from 10.77 percent to 11.26 percent (Exh. ES-VVR-1, at 78).

[181] In the Company's initial filing, the Non-Regulated Proxy Group CAPM results ranged from 10.34 percent to 10.64 percent (Exh. ES-VVR-1, at 78).

"(Moody's") A-rated public utility bond yields (Exh. ES-VVR-6, at 1-5). For the Non-Regulated Proxy Group, the Company uses an average of equity risk premiums, including historic returns for the S&P 500 Index less historic long-term corporate bonds and the prospective equity risk premium used in the CAPM described above (Exh. ES-VVR-6, at 7-8). After applying an adjustment for flotation costs, the updated RPM calculations produce ROE estimates of 10.84 percent for the Electric Proxy Group and 11.37 percent for the Non-Regulated Group (Exh. ES-VVR-Rebuttal-2, at 4).[182]

b. <u>Attorney General's Proposal</u>

To develop her rate of return recommendation, the Attorney General considers the results of a constant growth DCF analysis and a CAPM applied to a proxy group of 24 publicly held electric utility companies ("Attorney General Proxy Group") (Exhs. AG-JRW-1, at 22-23; JRW-3).[183] In addition, the Attorney General considers capital market conditions and the trend in authorized ROEs (Exh. AG-JRW-1, at 9-22). The Attorney General's DCF results are 8.80 percent for the Attorney General Proxy Group and

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[182] In the Company's initial filing, the RPM calculations produced ROE estimates of 10.66 percent for the Electric Proxy Group and 10.75 percent for the Non-Regulated Proxy Group (Exh. ES-VVR-1, at 78).

[183] The following were the Attorney General's selection criteria for her proxy group: (1) has at least 50 percent of revenues from regulated electric operations as reported in its Form 10-K filed with the U.S. Securities Exchange Commission; (2) is listed as a U.S.-based electric utility; (3) has an investment grade issuer credit rating by Moody's and S&P; (4) has paid a cash dividend in the past six months with no reductions or omissions; (5) has not been involved in an acquisition of another utility, nor has been the target of an acquisition in the past six months; and (6) has analysts' long-term EPS growth rate forecasts available (Exh. AG-JRW-1, at 22-23).

8.95 percent for the Electric Proxy Group (Exh. AG-JRW-1, at 56). For the CAPM, the Attorney General uses a market risk premium based on a review of studies and surveys, which produces an ROE estimate of 7.70 percent (Exh. AG-JRW-1, at 64-68). The Attorney General concludes that 7.70 percent to 8.95 percent represents a reasonable range of ROEs for NSTAR Electric and recommends an 8.95-percent ROE at the top of the range, giving primary weight to the DCF results and accounting for the recent rise in interest rates (Exh. AG-JRW-1, at 4, 71).

c. UMass Proposal

UMass recommends a 9.25-percent ROE based on an analysis of authorized returns for New England investor-owned utilities (Exh. UMASS-EP/RS-1, at 53-58). UMass states that an ROE of 9.25 percent would not threaten NSTAR Electric's financial integrity and ability to raise capital on reasonable terms (Exh. UMASS-EP/RS-1, at 58).

2. Positions of the Parties

a. Attorney General

i. Proxy Groups

The Attorney General asserts that the Attorney General Proxy Group and Electric Proxy Group are similar in risk based on six measures, including credit ratings, beta, financial strength, safety, earnings predictability, and stock price stability (Attorney General Brief at 87, <u>citing</u> Exh. AG-JRW-1, at 23). The Attorney General contends that the Department generally rejects the results of non-regulated proxy groups (Attorney General Brief at 86, <u>citing</u> D.T.E. 01-56, at 116; D.P.U. 96-50 (Phase I), at 132; D.P.U. 92-250, at 160-161; D.P.U. 905, at 48-49). The Attorney General claims that the companies in the Non-Regulated Proxy Group are very different from the electric distribution business and none of them operate under a regulatory construct like the electric distribution business (Attorney General Brief at 87). The Attorney General argues that the Department should not consider the Non-Regulated Proxy Group in its determination of the Company allowed ROE[184] (Attorney General Brief at 88).

ii. ROE Estimation Models

(A) DCF

The Attorney General contends that the Department should reject the Company's DCF analysis as it contains several substantive flaws that overstate the estimated cost of equity (Attorney General Brief at 81). First, she argues that the Company's outlier test eliminates low-end outliers while not affecting high-end outliers in the Electric Proxy Group (Attorney General Brief at 90). She claims that the asymmetric elimination of low-end outliers creates an upwardly biased estimate (Attorney General Brief at 90; Attorney General Reply Brief at 20). In addition, the Attorney General asserts that the Company relies solely on overly optimistic and upwardly biased EPS growth rates of Wall Street analysts and Value Line (Attorney General Brief at 90-92; Attorney General Reply Brief at 20).

The Attorney General also maintains that the Company's leverage adjustment is unwarranted (Attorney General Brief at 92-93). She claims that the market value of a firm's

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[184] Throughout this Order, the Department uses the terms authorized and allowed interchangeably.

equity is greater than the book value due to the firm's earning a return that is more than its equity costs (Attorney General Brief at 93). The Attorney General avers that the adjustment is unnecessary as there is no change in the Company's leverage, and its financial statements and fixed financial obligations remain the same (Attorney General Brief at 93). She contends that financial publications and investment firms report capitalizations on a book value basis, not on a market value basis (Attorney General Brief at 93). Further, Attorney General argues that regulatory commissions have rejected leverage adjustments because they increase ROEs for utilities that have high returns on common equity and decrease ROEs for utilities that have low returns on common equity (Attorney General Brief at 93).

Finally, the Attorney General contests the Company's flotation cost adjustment to its DCF results (Attorney General Brief at 93). She maintains that the Company has not provided evidence that flotation costs have been paid (Attorney General Brief at 92). In addition, she asserts that the Department has previously rejected the inclusion of issuance costs in the determination of ROE (Attorney General Brief at 92, citing D.P.U. 17-05, at 705-706; D.P.U. 90-121, at 180; D.P.U. 88-67 (Phase I) at 193; D.P.U. 86-280-A at 112; D.P.U. 85-137, at 100). The Attorney General argues that the Company has not provided sufficient evidence to change Department precedent (Attorney General Brief at 94).

(B) CAPM and RPM

The Attorney General contends that the major issue with the CAPM is the measurement and magnitude of the market premium (Attorney General Brief at 96). The Attorney General asserts that the Department should use a market risk premium no higher than 5.50 percent in any CAPM analysis used to determine NSTAR Electric's cost of equity (Attorney General Brief at 96). Further, she argues that there are five primary errors with the Company's CAPM: (1) the market risk premium of 7.50 percent; (2) the use of the empirical CAPM; (3) the size adjustment; (4) the use of leverage-adjusted betas; and (5) the flotation adjustment (Attorney General Brief at 96-105).

The Attorney General contends that the most significant error in the Company's CAPM is the market risk premium (Attorney General at 99). She avers that the Company's approach in computing its historical market risk premium suffers from several flaws, including stock market survivorship bias, the use of the arithmetic mean of stock price returns, an inappropriate time horizon, a failure to recognize changes in risk and return over time, a downward bias in historical bond returns, and unattainable return bias (Attorney General Brief at 99-100, citing Exh. AG-JRW-1, at 85-89). The Attorney General also claims that the Company's prospective market risk premium relies on the same biased EPS growth rates used in the Company's DCF analyses that are inconsistent with both historic and projected economic and earnings growth as reflected in projections of gross domestic product ("GDP") growth (Attorney General Brief at 100-102, citing Exh. AG-JRW-1, at 89-95; Attorney General Reply Brief at 21-23). Further, the Attorney General asserts that the Company's market risk premium component of the RPM contains the same flaws and should also be rejected (Attorney General Brief at 106).

The Attorney General also objects to the use of the empirical CAPM to estimate the Company's required ROE (Attorney General Brief at 98). She asserts that: (1) the empirical

CAPM has not been theoretically or empirically validated in refereed journals; and (2) the adjusted betas from Value Line already address the purported empirical issues with the CAPM (Attorney General Brief at 98, citing Exh. AG-JRW-1, at 83-84).

Additionally, the Attorney General argues that the size premium adjustment made by the Company is inappropriate and should be rejected (Attorney General Brief at 103-105). She notes that the size premiums are poor measures for size adjustments as they fail to account for survivorship and unattainable return biases (Attorney General Brief at 103-104). According to the Attorney General because public utilities are closely regulated, must gain approval for financial transactions, have standardized accounting and reporting requirements, and have earnings that are, to an extent, predetermined by the ratemaking process, their stocks do not exhibit a significant size premium (Attorney General Brief at 104). The Attorney General further argues that the Company's upward adjustments of betas to compensate for the difference between book value and market value capitalization suffers from the same flaw as the adjustment it made in its DCF analysis (Attorney General Brief at 98, citing Exh. AG-JRW-1, at 83-84).

iii. Required ROE

The Attorney General also argues that her 7.70-percent to 8.95-percent range of reasonable ROEs and 8.95 percent ROE recommendation are supported by current capital market conditions and a trend of declining authorized ROEs for other electric distribution companies (Attorney General Brief at 79-80, 95, 111-112; Attorney General Reply Brief at 13-14, 25-27). Specifically, she maintains that despite short-term expectations of higher inflation, the long-term inflation rate is still 2.50 percent (Attorney General Brief at 108). Further, the Attorney General avers that: (1) authorized ROEs for distribution companies nationally have trended downward since 2012, coinciding with decreasing interest rates; (2) Massachusetts ROEs have trended upward while the national averages have moved downward; and (3) the differences between Massachusetts and national average ROEs have become larger in recent years (Attorney General Brief at 110-111, citing Exh. AG-JRW-1, at 18-21; Attorney General Reply Brief at 26).

In addition, the Attorney General asserts that the investment risk of the Company is below the investment risk of the Electric Proxy Group because the Company has a higher credit rating and higher equity ratio (Attorney General Brief at 81, 84-85). She claims that the Company overestimates its required ROE by assuming NSTAR Electric is riskier than the Electric Proxy Group (Attorney General Brief at 80-83, 112; Attorney General Reply Brief at 18). The Attorney General avers that the electric distribution industry overall is among the lowest risk industries in the nation as measured by beta and, therefore, the industry's risk has declined (Attorney General Brief at 80, citing Exh. JRW-6).

Moreover, the Attorney General argues that NSTAR Electric's proposed PBR plan decreases the Company's financial risk relative to the proxy companies due to the exogenous cost factor and the rate adjustments (Attorney General Brief at 83, citing Exh. AG-JRW-1, at 8-9). Further, she contends that the stay-out provision of the PBR plan does not increase the Company's risk because the Company can break the stay-out provision (Attorney General Brief at 83 n.82, citing Exh. AG-JRW-1, at 8; D.P.U. 17-05, at 403-404 (2017)).

Finally, the Attorney General argues that the Department should reject the Company's request for an allowed ROE at the higher end of the reasonable range because of NSTAR Electric's quality of service (Attorney General Reply Brief at 29-30). The Attorney General asserts that the Company disingenuously claims that its PBR plan benefitted customers because, according to the Attorney General, the Company merely shifted costs from O&M by adjusting the capitalization rate (Attorney General Brief at 21-22; Attorney General Reply Brief at 30).

b. Acadia Center

Acadia Center agrees with UMass's recommendation of a 9.25-percent ROE (Acadia Center Brief at 9). Acadia Center argues that the allowed ROE should be significantly lower than the 10.5 percent proposed by the Company (Acadia Center Brief at 8). Acadia Center argues that comparable New England distribution companies can attract capital at lower rates without experiencing financial distress (Acadia Center Brief at 9).

c. Conservation Law Foundation

CLF argues that the Company's proposed ROE is unreasonably high and results in rates that are not just and reasonable (CLF Brief at 8). Further, CLF contends that the Company has failed to adequately explain why an increase in an already high ROE is warranted (CLF Brief at 8). CLF asserts that it is unreasonable for NSTAR Electric ratepayers to pay more than their neighbors for the same type of electric service and investments, subject to the same capital markets (CLF Brief at 8).

d. UMass

UMass argues that NSTAR Electric's proposed ROE is not commensurate with the return authorized for other New England EDCs or the national averages for electric rate cases in 2021 and the first quarter of 2022 (UMass Brief at 3, 35; UMass Reply Brief at 9-11). UMass contends that a 9.25-percent ROE reflects a level of return that the Company's peers have demonstrated to be sufficient to successfully provide similar services, maintain financial integrity, and attract capital (UMass Brief at 36; UMass Reply Brief at 9-11). UMass avers that experience in the region clearly demonstrates that an allowed ROE of 9.25 percent is sufficient to maintain financial integrity and to allow the firm to attract capital on reasonable terms (UMass Brief at 40, citing Exh. UMASS-EP/RS-1, at 57-58; Tr. 10, at 1150-1152).

e. Company

i. Proxy Groups

NSTAR Electric argues that, in determining its ROE, it has used appropriate proxy groups that include companies that: (1) are based on valid selection criteria; and (2) have sufficient financial and operating data to discern the investment risk of NSTAR Electric versus the comparison groups (Company Brief at 258, citing D.P.U. 20-120, at 413). The Company maintains that the objective in developing a proxy group is to develop a group of companies that are fundamentally similar with respect to operating, financial, and business risks of the utility seeking rate relief (Company Brief at 258-259, citing D.P.U. 08-35, at 176). NSTAR Electric claims that the companies in the Non-Regulated Proxy Group are comparable because they are lower risk consumer staple, food and beverage, chemicals processing, and transportation companies, which, like utilities, are less susceptible to changes in the business cycle (Company Brief at 259-260, 272, citing Exhs. ES-VVR-1, at 35; VVR-Rebuttal-1, at 91; Company Reply Brief at 28). Further, NSTAR Electric asserts that the Department has accepted the use of a non-regulated proxy group in setting the ROE (Company Brief at 260, 273, citing D.P.U. 13-75, at 302, 328; D.P.U. 12-25, at 416-17, 441). Finally, the Company maintains that the Attorney General's Proxy Group is too limited because it does not include comparable non-regulated companies (Company Brief at 272).

ii. ROE Estimation Models

(A) DCF

NSTAR Electric argues that the DCF analysis underestimates the Company's cost of equity because of the impact of recent long-term interest rates on the dividend yield (Company Brief at 262, citing Exh. ES-VVR-1, at 15-17, 48-49; Company Reply Brief at 27-28). The Company claims that investors view utility stocks as substitutions for fixed-income securities and that the recent downward pressure on long-term interest rates resulted in increased demand for utility stocks, raising utility stock prices and suppressing dividend yields (Company Brief at 262, citing Exh. ES-VVR-1, at 15-17, 48-49; Company Reply Brief at 27-28).

With respect to expected growth rates, the Company asserts that it correctly relies on EPS growth rates because a substantial amount of academic research has demonstrated that equity analyst forecasts have a significant influence on the growth expectations of investors (Company Brief at 260, citing Exh. ES-VVR-1, App. A at 2-3). The Company further argues that the Department should reject the Attorney General's claim that EPS growth rates are overly optimistic and upwardly biased consistent with the Department's prior findings on this issue (Company Brief at 275, citing Exh. ES-VVR-Rebuttal-1, at 35-37; D.P.U. 20-120, at 420; D.P.U. 19-120, at 374; Company Reply Brief at 27).

In addition, NSTAR Electric contends that it eliminated low-end and high-end outliers from the mean DCF results considered in the proposed ROE because those results did not pass fundamental tests of economic logic (Company Brief at 260-261, citing Exh. ES-VVR-1, App. B at 1-2). The Company reasons that rational investors will not invest in common stocks if the expected return is lower than or marginally higher than yields available on corporate debt securities (Company Brief at 260-261, citing Exh. ES-VVR-1, App. B at 2)

Finally, the Company argues that the Department should adopt the Company's adjustments to the DCF results to reflect the difference between market value and book value and to account for flotation costs (Company Brief at 261). The Company maintains that a leverage adjustment is necessary when the average market value equity capitalization of the proxy group companies is materially higher than the corresponding book value equity capitalizations (Company Brief at 261, citing Exh. ES-VVR-1, at App. C at 1-4). NSTAR Electric contends that the flotation adjustment accounts for the various costs incurred in the issuance of new equity stock (Company Brief at 261, citing Exh. ES-VVR-1, App. D at 1).

(B) CAPM and RPM

NSTAR Electric maintains that it ensured a balanced approach to estimate a market risk premium for the CAPM by using historical and prospective data and that the prospective market risk premium was calculated consistent with the Department's directives in D.P.U. 20-120, at 429-430 (Company Brief at 262-263). The Company argues that its market risk premium is reasonable and that the Attorney General's objections to the Company's calculation of the market risk premium are without merit (Company Brief at 280). Specifically, the Company maintains that the forecasted EPS growth rate for the S&P 500 is a reasonable market-based estimate that has been accepted by other utility commissions and is consistent with historical returns (Company Brief at 281).

The Company also asserts that it considers a size-adjusted CAPM based on academic studies that have shown small capitalization stocks have historically earned returns that are materially higher than returns predicted by the traditional CAPM (Company Brief at 264). In addition, the Company contends that it considers the empirical variant of the CAPM because extensive empirical evidence has shown that the risk-return relationship between beta and stock returns is flatter than what is predicted by the traditional CAPM (Company Brief at 264, citing Exh. ES-VVR-1, at 65). Further, the Company argues that it applies leverage and flotation adjustments to the CAPM results for the same reasons that those adjustments were applied to the DCF results (Company Brief at 263, citing Exhs. ES-VVR-1, at 60-66; ES-VVR-Rebuttal-1, at 5).

With respect to the RPM, NSTAR Electric argues that the Department relies on the RPM as a supplemental approach in determining the level of ROE (Company Brief at 282, citing D.P.U. 07-71, at 137). For the same reasons discussed above in relation to the market risk premium used in the CAPM, the Company claims that the Attorney General's objections to the market risk premium used in the RPM have no merit (Company Brief at 282). The Company avers, therefore, that the Department should at least supplement its calculation of the Company's ROE with the risk premium approach (Company Brief at 282).

iii. Required ROE

The Company maintains that its proposed ROE reflects capital market conditions and is the result of applying widely accepted common equity cost models (Company Brief at 292). NSTAR Electric argues that it is critical for the Department to recognize that the allowed ROE must position the Company to attract capital on a going-forward basis because it will not be able to maintain safe and reliable service without a fair return (Company Brief at 255). NSTAR Electric asserts that based on the legal standard for authorizing an ROE and the evidence in this proceeding, the Department should adopt the Company's recommended ROE of 10.50 percent (Company Brief at 255-256, 292).

In support of its requested ROE, NSTAR Electric also contends that the Department's decision must account for the recent increases in interest rates and inflation (Company Reply Brief at 25). The Company asserts that as interest rates have increased, and continue to increase, the cost of equity also increases (Company Reply Brief at 26, citing Tr. 14, at 1433, 1436-1439, 1441-1443; RR-DPU-40, Att. at 1; RR-ES-1).

Further, the Company claims that the intervenors' recommended ROEs based on national and regional authorized ROEs have no merit (Company Brief at 284-285, 288-291; Company Reply Brief at 22, 30, 32-34). NSTAR Electric argues that the Department should not rely on the 2021 and 2022 national averages for allowed ROEs or current authorized ROEs in New England because the sample sizes of these decisions are too small to be reliable, the national averages are skewed by jurisdictions that use formulaic approaches to determine an allowed ROE, and setting an allowed ROE based on averages from prior years would ignore the recent dramatic increase in interest rates and inflation (Company Brief at 284-285, 289-291, citing Tr. 9, at 1004-1006; Company Reply Brief at 22, 33, citing Exh. ES-VVR-Rebutal-1, at 18; Tr. 14, at 1437-1443; RR-DPU-40, Att. at 1; RR-ES-1, Att.).

With respect to credit rating, the Company maintains that the Department should reject the Attorney General's proposal to lower the Company's ROE based on a comparison to the proxy companies' credit ratings (Company Reply Brief at 24). NSTAR Electric asserts that there is no evidence showing a nexus between credit ratings and the specific, authorized cost of equity set for utilities and that the Department has rejected adjustments based on credit rating in the past (Company Reply Brief at 24, citing D.P.U. 20-120, at 430; D.P.U. 09-30, at 363, 365).

Turning to the proposed PBR plan, the Company argues that the proposed ten-year stay-out provision increases the Company's risk and, therefore, the Department should establish an ROE at the higher end of the reasonable range (Company Brief at 267, 283-284).

In particular, NSTAR Electric asserts that a “stay-out provision as part of a PBR plan may increase a company’s risks in meeting its financial requirements” (Company Brief at 265, 284, citing D.P.U. 20-120, at 431-432; Company Reply Brief at 25). The Company further claims that the Department has found that a ten-year stay-out provision as part of a company’s PBR mechanism increases the risks in meeting its financial requirements (Company Brief at 265, 284, citing D.P.U. 19-120, at 405).

Moreover, the Company avers that the electric utility industry is facing regulatory uncertainty associated with changes necessary to help achieve reductions in GHG emissions (Company Brief at 266, citing Exh. ES-CAH/DPH/ANB-1, at 116; Company Reply Brief at 25). NSTAR Electric contends that the changes will require significant increases in capital expenditures and will create regulatory uncertainty (Company Brief at 266; Company Reply Brief at 25).

Finally, NSTAR Electric argues that its ROE should be set at the higher end of the reasonable range based on qualitative factors (Company Brief at 267; Company Reply Brief at 31). The Company asserts that it has excellent service quality and exceeded its benchmarks during its current PBR plan (Company Brief at 267, citing Exh. ES-CAH-DPH-1, at 111). The Company also claims that it is a top performer in the industry with respect to reliability and customer service (Company Brief at 267-268, citing Exh. ES-CAH-DPH-1, at 112; Company Reply Brief at 31). Further, the Company maintains that during its current PBR plan the Company contained O&M costs to the direct benefit of customers and excelled at storm restoration (Company Brief at 267-268, citing Exh. ES-CAH-DPH-1, at 112-114; Company Reply Brief at 31-32).

3. Analysis and Findings

a. Proxy Groups

The use of a proxy group of companies is standard practice in setting an ROE that is comparable to returns on investments of similar risk. D.P.U. 08-35, at 176-177; D.T.E. 99-118, at 80-82; D.P.U. 92-78, at 109-110; Western Massachusetts Electric Company, D.P.U. 1300, at 97 (1983). The use of a proxy group is especially relevant for evaluation of a cost of equity analysis when a distribution company does not have common stock that is publicly traded, as is the case with NSTAR Electric (Exh. ES-VVR-1, at 32). D.P.U. 08-35, at 176-177; D.T.E. 99-118, at 80-82; D.P.U. 92-78, at 109-110. The Department has stated that companies in the proxy group must have common stock that is publicly traded[185] and must be generally comparable in investment risk. D.P.U. 1300, at 97.

In our evaluation of the proxy groups used by the Company and the Attorney General, we recognize that it is neither necessary nor possible to find a group in which the companies match NSTAR Electric in every detail. D.T.E. 99-118, at 80; D.P.U. 87-59, at 68; Boston Gas Company, D.P.U. 1100, at 135-136 (1982). Rather, we may rely on an analysis that employs valid criteria to determine which companies will be in the proxy group and that provides sufficient financial and operating data to discern the investment risk of NSTAR

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[185] An important aspect of the criteria for a proxy group is that financial information is readily available for publicly traded companies.

Electric relative to the proxy group. D.T.E. 99-118, at 80; D.P.U. 87-59, at 68; D.P.U. 1100, at 135-136.

The Department expects diligence by parties in assembling proxy groups that will produce statistically reliable analyses required to determine a fair rate of return for the company. D.P.U. 10-55, at 480-482. The Department has previously found that overly exclusive selection criteria may affect the statistical reliability of a proxy group, especially if such screening criteria result in a limited number of companies in the proxy group. D.P.U. 10-55, at 480-482.[186] The Department has directed parties to limit criteria to the extent necessary to develop a broader as opposed to a narrower proxy group. D.P.U. 10-114, at 299; D.P.U. 10-55, at 481-482. To the extent that a particular company's characteristics differ from those of the others in a proxy group, those differences should be identified in sufficient detail to enable a reviewer to discern any effects on investment risk. D.P.U. 10-114, at 299; D.P.U. 10-55, at 480-482. Additionally, the Department places less reliance on a proxy group if the member companies are substantially different from the company in the case. D.P.U. 90-121, at 166.

After review, the Department finds that NSTAR Electric and the Attorney General each employed a set of valid criteria to select the Electric Proxy Group and Attorney General

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[186] The challenge when selecting a proxy group is to narrow it sufficiently to reflect the risks faced by the company in question and, at the same time, find a large enough proxy group to bring confidence to the ultimate result by mitigating any distortion introduced by possible measurement error or vagaries in an individual company's market data. In Re Public Service Company of New Hampshire, 90 NH PUC 230, 247 (2005).

Proxy Group, and the Department finds that both parties provided sufficient information to draw conclusions about the relative risk characteristics of the Company versus the members of the proxy groups (Exhs. ES-VVR-1, at 30-31; AG-JRW-1, at 22-23; AG-JRW-3). D.P.U. 12-25, at 402; D.P.U. 09-30, at 307. Therefore, the Department will accept the Company's Electric Proxy Group and the Attorney General Proxy Group to determine NSTAR Electric's allowed ROE.

Periodically, companies have proffered a comparable earnings approach to estimate ROE as a supplement to DCF and risk premium analyses. D.T.E. 01-56, at 113-116. The comparable earnings approach uses both historical returns and forecasted returns for a group of non-utility companies, which proponents of this approach have selected based on financial risk criteria from resources such as Value Line, Moody's, and S&P. D.P.U. 13-75, at 320; D.P.U. 12-25, at 433-436; D.P.U. 08-35, at 208-211; D.T.E. 01-56, at 113-116. Therefore, the comparable earnings approach is similar to NSTAR Electric's proposal to estimate its ROE based on DCF and risk premium analyses using historical and forecasted data of the Non-Regulated Proxy Group, which was selected based on similar financial risk criteria (Exhs. ES-VVR-1, at 32-37; ES-VVR-4; ES-VVR-5; ES-VVR-6). The Department has generally rejected the results of the comparable earnings analysis on the basis that the financial risk criteria provided by the proponents, including beta, financial strength, price stability, and credit rating, were not sufficient to establish the comparability of the non-price-regulated firms with the distribution company being considered. D.P.U. 13-75, at 321-322; D.P.U. 12-25, at 435-436; D.P.U. 08-35, at 210; D.T.E. 01-56, at 113-116.

After review, we find that NSTAR Electric's proposal to rely on a Non-Regulated Proxy Group suffers from similar limitations to those identified with respect to the comparable earnings approach. The Department has repeatedly found that the use of beta as a criterion in selecting a comparable group of companies is not a reliable investment risk indicator given its statistical measurement limitations. D.P.U. 13-75, at 321-322; D.P.U. 12-25, at 435; D.P.U. 08-35, at 210; D.T.E. 01-56, at 113-116. The Department also has found that the financial risk criteria employed by NSTAR Electric do not fully capture the value of operating a regulated monopoly in a revenue decoupled market. D.P.U. 13-75, at 321-322; D.P.U. 12-25, at 435. Moreover, while NSTAR Electric correctly states that we must ensure a proxy group of companies is fundamentally similar with respect to the operating, financial, and business risks of the utility, the Company provided little evidence concerning how the operating and business risks of the Non-Regulated Proxy Group are similar to an electric distribution company, other than opinion testimony, which contrasts with the Attorney General's opinion testimony (Exhs. ES-VVR-1, at 35; ES-VVR-Rebuttal-1, at 91; AG JRW-1, at 74; Tr. 9, at 1047).[187] D.P.U. 08-35, at 176.

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[187] Further, in the Company's testimony it stated that the Non-Regulated Proxy Group behaved similarly to utility companies in the business life cycle, but during evidentiary hearings the Company represented that the business life cycle did not apply to utilities at all, which creates further uncertainty that the Non-Regulated Proxy Group is comparable to NSTAR Electric (Exh. ES-VVR-Rebuttal-1, at 91; Tr. 9, at 1047).

NSTAR Electric correctly identifies two instances in which the Department has considered ROE estimates based on non-regulated companies in our determination of a utility's allowed ROE. D.P.U. 13-75, at 286-287; D.P.U. 12-25, at 402. The Company, however, does not present a complete picture of the Department's analysis in those cases. NSTAR Electric fails to acknowledge that, in both proceedings, the Department stated that the non-regulated businesses were potentially riskier and, all else equal, potentially more profitable than the petitioning utility company, and the Department considered that disparity in risk in determining the appropriate ROE. D.P.U. 13-75, at 286-287; D.P.U. 12-25, at 402.[188] Ultimately, the Department authorized ROEs in those Orders that were, respectively, 303 basis points and 251 basis points lower than the DCF model results for the non-regulated business, which indicates that the Department placed limited weight on the ROE estimates based on the proxy group of non-regulated companies. D.P.U. 13-75, at 293, 329; D.P.U. 12-25, at 407, 444.

Based on the findings above, while there is some evidence that the Non-Regulated Proxy Group has similar financial risk to NSTAR Electric, the Company has provided limited evidence demonstrating that the consumer staple, food and beverage, chemicals processing, and transportation companies have comparable operations and business risk to an electric distribution company (Exhs. ES-VVR-1, at 35; VVR-Rebuttal-1, at 91). Therefore,

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[188] The Department has repeatedly found that the presence of unregulated operations in a proxy group would tend to produce model results that overstate a utility's cost of equity. D.P.U. 17-170, at 307; D.P.U. 15-80/D.P.U. 15-81, at 291-292; D.P.U. 10-114, at 335.

the Department will place limited weight on the ROE estimates based on the Non-Regulated Proxy Group in our determination of the allowed ROE.

b. ROE Estimation Models

i. DCF Model

The DCF is a commonly used valuation model based on the fundamental premise that investors value financial assets on the basis of expected future cash flows, discounted by an appropriate risk-adjusted rate of return (Exhs. ES-VVR-1, at 42; AG-JRW-1, at 39). As discussed above, both the Company and the Attorney General rely on DCF analyses to recommend an allowed ROE (Exhs. ES-VVR-1, at 5; AG-JRW-1, at 6). The parties disagree on three key issues regarding their respective DCF analyses: (1) the impact of current market conditions on the DCF results; (2) the appropriate estimated growth rate; and (3) the Company's adjustments to the DCF analysis for flotation costs, the leverage adjustment, and outliers.

The Department recently considered the relationship between low interest rates and utility stock prices over the last several years and whether a projected increase in long-term interest rates caused the DCF analysis to understate the cost of equity. D.P.U. 20-120, at 416-419. The Department found that, although utility stocks had increased above historic levels in conjunction with low interest rates, the evidence in that proceeding that long-term interest rates would change was speculative. D.P.U. 20-120, at 417-419. In this proceeding, the record is clear that long-term interest rates have increased compared to the period of time from which the parties derived the dividend yields used in the DCF analyses

(Exh. ES-VVR-Rebutal-1, at 23-26; Tr. 14, at 1463). We also have considered the Attorney General's evidence of investors forecasting that utility stocks will retain their high valuations in the near term (Tr. 14, at 1449-1452; RR-DPU-48). Based on the foregoing evidence, the Department finds that there is greater certainty that the DCF results understate the Company's cost of equity. The Department takes these findings into consideration in the determination of the reasonable range below.

Determining the appropriate long-term growth expectations of investors in a DCF analysis is often difficult and controversial. D.P.U. 15-155, at 365. As discussed above, the Company and Attorney General use different growth rates in their respective DCF analyses, and each party objects to the other's choice of growth rates. Regarding EPS growth rates, the Department has previously found that federal regulators have mitigated the systemic bias in overly optimistic stock recommendations, and the Department has accepted DCF results that rely on EPS growth rates. D.P.U. 20-120, at 419-420; D.P.U. 19-120, at 374. We reaffirm those findings.

The Company uses EPS growth rates between 5.20 percent and 5.60 percent for the Electric Proxy Group (Exhs. ES-VVR-3, at 1, 2; ES-VVR-Rebuttal-3, at 1, 2). The Attorney General uses a growth rate of 5.50 percent for the Attorney General Proxy Group and a growth rate of 5.75 percent for the Electric Proxy Group (Exh. AG-JRW-1, at 54-55). Based on our precedent and the supporting evidence provided by the parties, the Department finds that both the Company's and the Attorney General's approaches to the expected growth rates are reasonable (Exhs. ES-VVR-1, App. A at 3-10; AG-JRW-1, at 45-55).

Turning to the Company's proposed adjustments for flotation costs, the Department has consistently rejected issuance cost adjustments for purposes of determining an allowed ROE. D.P.U. 10-70, at 259; D.P.U. 90-121, at 180 ("[t]he use of a flotation cost adjustment to the cost of equity is not acceptable"). The Department has found in several Orders that investors already take into account issuance costs in their decision to purchase a stock at a given price. D.P.U. 90-121, at 180, citing D.P.U. 88-67 (Phase I) at 193; D.P.U. 87-260, at 105-106; D.P.U. 86-280-A at. 112; D.P.U. 85-137, at 100. The Department finds that NSTAR Electric has failed to present any evidence or argument to justify a departure from long-standing precedent (Exh. DPU 10-16). Accordingly, the Department will not rely on the Company's DCF results without adjustment for flotation costs in the determination of the reasonable range.

The Department has also consistently rejected leverage adjustments (Exhs. ES-VVR-1, at 48; ES-VVR-1, App. C). D.P.U. 10-55, at 513; D.P.U. 09-39, at 387; D.T.E. 05-27, at 298; D.T.E. 03-40, at 357-359; D.T.E. 01-56, at 105-106; D.P.U. 906, at 100-101; Eastern Edison Company, D.P.U. 837/968, at 49 (1982). The Company's proposed leverage adjustment relies on a comparison between book and market capitalization and, therefore, has similar elements to the price-book ratio method of determining a utility's cost of equity. D.T.E. 01-56, at 105. The Department has frequently rejected the price-book analysis because it fails to recognize variables such as a company's geographic location, load factors, and customer make-up, which can affect price-book ratios. D.T.E. 01-56, at 105, citing D.P.U. 906, at 100-101. Additionally, the price-book analysis has been found to rely excessively on investor perceptions of the relationship between market and book prices in their investment decisions. D.T.E. 01-56, at 105, citing D.P.U. 837/968, at 49.

These weaknesses of the price-book ratio analysis are also present in NSTAR Electric's leverage adjustment. The Company asserts that investors require a higher return because the book value of their investment is exceeded by its market value (Exh. ES-VVR-1, App. C, at 1). Considering the multiplicity of factors that affect investor decisions on the valuation of a utility's common stock, the Department considers the Company's market/book analysis as an implicit attempt to automatically ensure a market-to-book ratio of one-to-one. This automatic assurance would serve to remove an inherent aspect of utility management, that is, to "bear the brunt of inefficient decisions and reap the rewards of efficiency." D.T.E. 01-56, at 106, citing D.P.U. 906, at 100. The Department is not obligated to ensure that market-to-book ratios remain on a one-to-one basis. The Department finds that NSTAR Electric has failed to present any evidence or argument to justify a departure from long-standing precedent (Exh. DPU 10-15). Therefore, the Department places no weight on the Company's proposed leverage adjustment.

Finally, the Company applied low-end and high-end outlier thresholds to the DCF results (Exhs. ES-VVR-3, at 1, 2; ES-VVR-Rebuttal-3, at 1, 2). While the Department has concerns that the design of NSTAR Electric's outlier test could lead to asymmetrical results that skew the cost of equity estimate, in this particular case, the Company's DCF results screened for outliers are comparable to the Attorney General's DCF results without a screen for outliers (Exhs. ES-VVR-3, at 1, 2; ES-VVR-Rebuttal-3, at 1, 2; AG-JRW-1, at 55; Tr. 14, at 1474).

The Company's updated mean DCF results for the Electric Proxy Group, without the adjustments for flotation costs or the leverage adjustment, range from 8.50 percent to 9.20 percent, and the Attorney General's DCF results for the Attorney General Proxy Group and Electric Proxy Group are 8.80 percent and 8.95 percent (Exhs. ES-VVR-Rebuttal-3, at 1, 2; AG-JRW-1, at 55). Based on the findings above, the Department will consider these DCF results in our determination of the reasonable range below. In addition, without the adjustment for flotation costs and the leverage adjustment, the Company's updated mean DCF results for the Non-Regulated Proxy Group range from 10.30 percent to 11.70 percent (Exhs. ES-VVR-4, at 1-2; ES-VVR-Rebuttal-4, at 1, 2). Consistent with our findings on the Non-Regulated Proxy Group above, the Department will accord limited weight to the Non-Regulated Proxy Group DCF results in our determination of the reasonable range below.

ii. CAPM

The Department has previously found, and the Company has acknowledged, that the traditional CAPM analysis as a basis for determining a utility's cost of equity has limited value because of several limitations, including some questionable assumptions that underlie the model (Exh. ES-VVR-1, at 52). D.P.U. 20-120, at 423; D.P.U. 19-120, at 383; D.P.U. 17-170, at 298; D.P.U. 10-55, at 514; D.P.U. 08-35, at 207; Commonwealth

Electric Company, D.P.U. 956, at 54 (1982).[189] As a result, it has been the Department's long-standing practice to accord the results of the CAPM limited weight. See, e.g., D.P.U. 17-05-H at 9 & n.9; D.P.U. 20-120, at 423-425; D.P.U. 19-120, at 383-385.

Recently, in an effort to consider a broader range of CAPM analyses in future base distribution rate proceedings, the Department directed all electric and gas companies to submit a CAPM analysis that estimates the market return based on the Value Line 1,700 Stock Universe using Value Line's median of estimated dividend yields and estimated price appreciation potential in addition to the other ROE estimation models that, in the judgment of the party, provide a reliable estimate of the cost of equity. D.P.U. 20-120, at 429-430. As discussed above, NSTAR Electric estimated a market-return based on a one-quarter weighting of a DCF analysis on the S&P 500 Index, a one-quarter weighting of a DCF analysis on the Value Line 1,700 Stock Universe, and a one-half weighting of the historical returns (Exhs. VVR-5, at 1-2; ES-VVR-Rebuttal-5, at 1-2). After review, the Department finds that the Company's proposal complies with the Department's directive and, in this proceeding, incorporating the expected growth based on Value Line's data ensured a more conservative

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[189] In D.P.U. 08-35, at 207 n.131, the Department noted the following assumptions of the CAPM: (1) capital markets are perfect with no transaction costs, taxes, or impediments to trading, all assets are perfectly marketable, and no one trader is significant enough to influence price; (2) there are no restrictions to short-selling securities; (3) investors can lend or borrow funds at the risk-free rate; (4) investors have homogeneous expectations (i.e., investors possess similar beliefs on the expected returns and risks of securities); (5) investors construct portfolios on the basis of the expected return and variance of return only, implying that security returns are normally distributed; and (6) investors maximize the expected utility of the terminal value of their investment at the end of one period.

approach in developing the market return and the Company's weighting of the Value Line, S&P 500 Index, and historical data produced a balanced analytical approach to the CAPM (Exhs. ES-VVR-1, at 6; ES-VVR-Rebuttal-1, at 76; ES-VVR-5; ES-VVR-Rebuttal-5).[190] The Department will take these findings into consideration in our determination of the reasonable range below.

The Department previously has rejected attempts to adjust CAPM-derived ROE calculations for company size. D.P.U. 10-70, at 270-271; D.P.U. 08-35. In this proceeding, both the Attorney General and the Company produce several academic studies that support opposite conclusions on whether a size adjustment is warranted (Exhs. ES-VVR-1, at 63; ES-VVR-Rebuttal-1, at 86-88; AG-JRW-1, at 95-98). Further, the Company was unable to indicate whether investors consider the size-adjusted CAPM more reliable than the traditional CAPM, and the size-adjusted CAPM has not been adopted by a significant number of regulatory authorities for purposes of determining an allowed ROE (Exhs. ES-VVR-Rebuttal-1, at 88; DPU 64-2). Overall, the Department finds that the record evidence pertaining to the propriety of a size-adjustment is inconclusive. Therefore, the

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[190] The Department notes that there are multiple accepted approaches employed by analysts to estimate the market return, and the Department's findings should not be construed as a determination that the Department will only accept NSTAR Electric's approach in future cases. D.P.U. 20-120, at 424 & n.211 ("Accepted approaches to estimating the market return include using realized market returns during a historical time period; applying the DCF model to a representative market index, such as the S&P 500; and surveying academic and investment professionals."). The Department will continue to evaluate the probative value of parties' CAPM analyses, variations thereof, and other ROE estimation models on a case-by-case basis.

Department will accord the Company's size-adjusted CAPM results limited weight in the determination of the reasonable range below.

The Department previously has rejected the empirical variation of the CAPM, as well. D.P.U. 10-70, at 271. We are not persuaded to deviate from our prior treatment of the empirical CAPM results because NSTAR Electric and the Attorney General provide contradictory expert testimony on the validity of the empirical CAPM, the Company was unable to indicate whether investors consider the empirical CAPM more reliable than the traditional CAPM, and only a small number of regulatory jurisdictions have relied on the empirical CAPM for rate setting purposes (Exhs. ES-VVR-1, at 63-66; ES-VVR-Rebuttal-1, at 79-85; AG-JRW-1, at 83-84; DPU 64-2). Therefore, the Department finds that it is appropriate to give limited weight to the Company's empirical CAPM results in our determination of the reasonable range below.

NSTAR Electric's CAPM results include flotation cost adjustments and leverage adjustments. For the same reasons discussed in Section XVI.D.3.b.i above, the Department rejects the Company's flotation cost adjustments and leverage adjustments. To remove the leverage adjustment, the Department applies a beta of 0.89 for the Electric Proxy Group and a beta of 0.86 for the Non-Regulated Proxy Group to the Company's updated CAPM schedules, which do not include the flotation cost adjustments (Exh. ES-VVR-Rebuttal-5).[191] The traditional CAPM results without flotation costs or leverage adjustments are

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[191] The Company applies the flotation cost adjustments in its testimony (Exh. ES-VVR-1, at 66).

10.50 percent for the Electric Proxy Group and 10.26 percent for the Non-Regulated Proxy Group (Exh. ES-VVR-Rebutal-5, at 1-4). The size-adjusted CAPM results without flotation costs or leverage adjustments are 10.99 percent for the Electric Proxy Group and 10.04 percent for the Non-Regulated Proxy Group (Exhs. ES-VVR-5, at 1-4; ES-VVR-Rebutal-5, at 1-4). The empirical CAPM results without flotation costs or leverage adjustments are 10.71 percent for the Electric Proxy Group and 10.53 percent for the Non-Regulated Proxy Group (Exhs. ES-VVR-5, at 1-4; ES-VVR-Rebutal-5, at 1-4).

The Attorney General presents a considerably different CAPM result of 7.70 percent (Exh. AG-JRW-1, at 70). The Attorney General places little weight on her CAPM results in her recommended ROE of 8.95 percent, which is 125 basis points higher than her CAPM results and equal to her highest DCF result (Exh. AG-JRW-1, at 33, 95). The Attorney General adopts the position that the results of the CAPM are less reliable because of the difficulty in determining a market risk premium (Exh. AG-JRW-1, at 3; Tr. 14, at 1467). Moreover, the Attorney General has given little to no weight to her CAPM results for many years (Tr. 14, at 1470). Considering the Attorney General's position that her CAPM result is unreliable, the Department places no weight on the results of the Attorney General's CAPM estimate in determining the appropriate ROE.

iii. RPM

The Department has repeatedly found that an equity risk premium analysis can overstate the amount of company-specific risk and, therefore, the cost of equity. D.P.U. 17-05-H at 11-12; D.P.U. 17-05, at 701-702; D.P.U. 10-114, at 322; D.P.U. 88-67

(Phase I) at 182-184. More specifically, the Department has long criticized the use of long-term corporate or public utility bonds yields because these instruments may have risks that could be diversified with the addition of common stock in investors' portfolios and, therefore, the RMP overstates the risk accounted for in the resulting cost of equity. D.P.U. 10-114, at 322; D.P.U. 90-121, at 171; D.P.U. 88-67 (Phase I) at 182-183. The Department has found that because the RPM is not a forward-looking approach, and is, instead, based on current market conditions, current U.S. Treasury bond yields are the appropriate measure of the risk-free rate in the RPM. D.P.U. 17-05-H at 12, citing D.P.U. 17-05, at 702-703; D.P.U. 13-75, at 319; D.P.U. 12-25, at 433.

Despite the Department's long-standing precedent, and the Company's acknowledgement that "U.S. Treasury securities remain the closest thing to a risk-free asset," the Company relies on projected corporate and public utility bond yields in its RPM (Exhs. ES-VVR-1, at 55, 69-70; ES-VVR-6; ES-VVR-Rebuttal-6). For these reasons, the Department finds that NSTAR Electric's RPM results of 10.66 percent and 11.37 percent are inconsistent with Department precedent and overstate the Company's required ROE (Exhs. ES-VVR-1, at 77; ES-VVR-Rebuttal-1, at 5). Therefore, the Department will not rely on the results of the Company's RPM in our determination of the reasonable range.

c. Authorized ROEs

The Attorney General, Acadia Center, and UMass all argue that the Department should determine NSTAR Electric's ROE based on national and regional allowed ROEs. As an initial matter, the Department reaffirms its finding that the purported upward trend in

ROEs granted in Massachusetts since 2012 is skewed by decisions at the start of that period that set the authorized ROE for those companies at the low-end of the reasonable range to account for deficient management practices (Exh. AG-JRW-1, at 20). D.P.U. 20-120, at 435-436. Moreover, while ROEs granted in other jurisdictions may be indicative of general overall trends, without knowing what quantitative and qualitative factors were considered in these other regulatory agencies, the Department is unable to conclude that these ROEs are appropriate for NSTAR Electric. D.P.U. 19-120, at 363; D.P.U. 17-170, at 282.

In addition, the record demonstrates that the national and regional authorized ROEs relied on by the intervenors come from a small sample of utility companies, and setting an allowed ROE based on averages from prior years would ignore the more recent change in market conditions (Exh. ES-VVR-Rebutal-1, at 18; Tr. 9, at 1004-1006; Tr. 14, at 1437-1443; RR-DPU-40, Att. at 1; RR-ES-1, Att.). Therefore, the Department places no weight on the ROE trends cited by the Attorney General and no weight on the ROEs proposed by Acadia Center and UMass.

d. Reasonable Range

When setting the range of reasonableness and then determining the allowed ROE, the Department is guided by the standard set forth in Federal Power Commission v. Hope Natural Gas Company, 320 U.S. 591 (1944) ("Hope") and Bluefield Waterworks and Improvement Company v. Public Service Commission of West Virginia, 262 U.S. 679 (1923) ("Bluefield"). The allowed ROE should preserve a company's financial integrity, allow it to attract capital on reasonable terms, and be comparable to returns on investments of similar risk. Hope at 603; Bluefield at 692-693. The allowed ROE should be determined "having regard to all relevant facts." Bluefield at 692. Both quantitative and qualitative factors must be considered in determining an allowed ROE. D.P.U. 11-01/D.P.U. 11-02, at 424; D.P.U. 08-27, at 134-138; D.T.E. 02-24/25, at 229-231; D.P.U. 92-78, at 115; D.P.U. 89-114/90-331/91-80 (Phase I) at 224-225.

The use of empirical analyses in this context is not an exact science. D.P.U. 17-170, at 305; D.P.U. 15-155, at 377; see also Southern Bell Telephone and Telegraph Company v. Louisiana Public Utility Commission, 239 La. 175, 225 (1960) (ascertainment of a fair return in a given case is a matter incapable of exact mathematical demonstration); United Railways & Electric Company of Baltimore v. West, 280 U.S. 234, 250 (1930) (what will constitute a fair return is not capable of exact mathematical demonstration). Conducting a model-based ROE analysis requires the analyst to make a number of subjective judgments. Even in studies that purport to be mathematically sound and highly objective, crucial subjective judgments are made along the way and necessarily influence the end result. Western Massachusetts Electric Company, D.P.U. 18731, at 59 (1977). Each level of judgment to be made in these models contains the possibility of inherent bias and other limitations. D.T.E. 01-56, at 117; D.P.U. 18731, at 59.

While the results of analytical models are useful, the Department must ultimately use our own judgment of the evidence to determine an appropriate ROE. We must apply to the record evidence and argument with the considerable judgment and agency expertise necessary to determine the appropriate use of the empirical results. Our task is not a mechanical or model driven exercise. D.P.U. 08-35, at 219-220; D.P.U. 07-71, at 139; D.T.E. 01-56, at 118; D.P.U. 18731, at 59; see also Boston Edison, 375 Mass. 1, 15 ("experience has shown that, in making a determination as elusive as estimating the cost of equity capital, 'mathematical formulas and rules of thumb are obsolete'" citing A.J.G. Priest, Principles of Public Utility Regulation 196 (1969)).[192]

The Department typically accords the most weight to the results of the DCF analysis in determining the reasonable range. D.P.U. 20-120, at 396; D.P.U. 17-05-H at 13. Based on our precedent and findings above, the Department finds that it is appropriate in this case to give the most weight to the mean DCF results for the Electric Proxy Group and the Attorney General Proxy Group, with a range of results from 8.50 percent to 9.20 percent (Exhs. ES-VVR-3, at 1, 2; ES-VVR-Rebuttal-3, at 1, 2; AG-JRW-1, at 55). Additionally, the Department finds that it is appropriate in this case to give more than limited weight to the Company's traditional CAPM results for the Electric Proxy Group of 10.50 percent because of the impact of changing interest rates on the DCF analysis, but not as much weight as the DCF because of the questionable assumptions underlying the CAPM. Further, based on the

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[192] As the Department stated in New England Telephone and Telegraph Company, D.P.U. 17441, at 9 (1973):

> Advances in data gathering and statistical theory have yet to achieve precise prediction of future events or elimination of the bias of the witnesses in their selection of data. Thus, there is no irrefutable testimony, no witness who has not made significant subjective judgments along the way to his conclusion, and no number that emerges from the welter of evidence as an indisputable "cost" of equity.

findings above with respect to the Non-Regulated Proxy Group and the CAPM variants, the Department finds it appropriate to give limited weight to the DCF results of the Non-Regulated Proxy Group, the size-adjusted CAPM and empirical CAPM results of the Electric Proxy Group, and the CAPM results of the Non-Regulated Group. Finally, because the Company's RPM results overstate the cost of equity and the Attorney General does not find her CAPM result to be reliable, the Department does not rely on those model results to determine the reasonable range. In our judgment, based on a review of the evidence presented in this case, the arguments of the parties, and the considerations set forth above, the Department finds that 9.40 percent to 10.00 percent, with a midpoint of 9.70 percent, is a reasonable range of ROEs for NSTAR Electric in this proceeding.

e. Market Conditions

In determining an allowed ROE within the reasonable range, the Department has previously considered evidence of the impact that changing market conditions will have on the quantitative ROE estimates. D.P.U. 17-05-H, at 15-16; D.P.U. 20-120, at 434-435; D.P.U. 19-120, at 357-362; D.P.U. 17-170, at 280-281. Projecting future market trends, whether interest rates, dividends and earnings growth, or GDP growth is difficult through surveys and modeling alike, and the Department will reject proposals to adjust cost of equity estimates without compelling evidence. D.P.U. 20-120, at 434-435; D.P.U. 17-170, at 280.

During this proceeding, the Federal Reserve Board indicated that it would shift to a more aggressive monetary policy to address the highest inflation rate seen in the past 40 years (Exh. ES-VRR-Rebuttal-1, at 21). In May 2022, the Federal Reserve Board raised the Federal Funds target rate, indicated that it would institute further rate increases at subsequent meetings through the year, and stated that it would begin to reduce the size of its securities portfolio (Exh. ES-VRR-Rebuttal-1, at 29). From the end of 2021 to June 2022, the 30-year U.S. Treasury bond yield increased over 100 basis points, A-rated long-term utility bond yields increased by 150 basis points, and economists expect longer-term interest rates will continue to trend higher while the Company's rates are in effect (Exh. VVR-Rebuttal-1, at 23, 27-28; RR-DPU-40; RR-ES-1).

Based on the evidence, NSTAR Electric contends that the Department's decision must account for the recent increases in interest rates and inflation because as interest rates increase the cost of equity also increases (Company Reply Brief at 26, citing Tr. 14, at 1433, 1436-1439, 1441-1443; RR-DPU-40, Att. at 1; RR-ES-1). After review, the Department concludes that, although there is not a one-to-one correlation between an increase in long-term debt interest rates and the cost of equity, NSTAR Electric's argument that current market conditions will increase the cost of equity while the Company's rates are in effect is more persuasive than the Attorney General's argument that an adjustment is not warranted. Therefore, the Department will set the Company's allowed ROE in the upper half of the reasonable range to account for market conditions.

f. Qualitative Factors

The Department has found that both quantitative and qualitative factors must be taken into account in determining an allowed ROE. D.P.U. 11-01/D.P.U. 11-02, at 424; D.P.U. 08-27, at 134-138; D.T.E. 02-24/25, at 229-231; D.P.U. 92-78, at 115;

D.P.U. 89-114/90-331/91-80 (Phase I) at 224-225; see also Boston Edison, 375 Mass. 1, 11 ("The rate of return is not an immutable number, but rather one chosen from a range of reasonable rates and determined by the Department to be appropriate under the circumstances"); Boston Gas Company v. Department of Public Utilities, 359 Mass. 292, 305 (1971) (holding that the Department was not required to rely on any particular group of comparative figures to estimate ROE, as "[s]uch comparisons usually can be no more than general guides to be appraised by the [Department] in considering the fairness of rates . . . ."). It is both the Department's long-standing precedent and accepted regulatory practice[193] to consider qualitative factors such as management performance and customer service in setting a fair and reasonable ROE. See, e.g., D.P.U. 09-39, at 399-400 (considered company's assistance to municipal and public safety officials to restore power to the customers of another company following a severe ice storm in setting allowed ROE); D.P.U. 12-86, at 257-258 (deficiencies regarding affiliate transactions and selection of rate

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[193] See, e.g., In re Citizens Utilities Company, 171 Vt. 447, 453 (2000) (general principle that rates may be adjusted depending on the adequacy of the utility's service and the efficiency of its management); Gulf Power Company v. Wilson, 597 So.2d 270, 273 (1992) (regulator was authorized to adjust rate of return within reasonable range to adjust for mismanagement); Wisconsin Public Service Corp. v. Citizens' Utilities Board, Inc., 156 Wis.2d 611, 616 (1990) (prudence is a factor regulator considers in setting utility rates and can affect the allowed ROE); US West Communications, Inc. v. Washington Utilities & Transportation Commission, 134 Wash.2d 74, 121 (1998) (a utility commission may consider the quality of service and the inefficiency of management in setting a fair and reasonable rate of return); North Carolina ex rel. Utilities Commission v. General Telephone Company of the Southeast, 285 N.C. 671, 681 (1974) (the quality of the service rendered is, necessarily, a factor to be considered in fixing the just and reasonable rate therefore).

case consultants warranted ROE at lower end of reasonable range). With respect to a company's performance, the Department has determined that where a company's actions have had the potential to affect ratepayers or have actually done so, the Department may take such actions into consideration in setting the ROE. D.P.U. 11-01/D.P.U. 11-02, at 424; D.T.E. 02-24/25, at 231; D.P.U. 85-266-A/271-A at 6-14. Thus, the Department may set ROEs that are at the higher end or lower end of the reasonable range based on above-average or subpar management performance and customer service.

The Department has reviewed the record evidence and finds that the Company has met or exceeded its service quality standards and benchmarks (Exh. ES-CAH-DPH-1, at 111). The Company has also demonstrated strong performance with respect to reliability and storm restoration (Exh. ES-CAH-DPH-1, at 112-114). The Department, however, also notes that the Company scaled back its manhole inspections in recent years and has experienced an uptick in manhole disturbance events since its last rate case, particularly in 2018, 2019, and 2022 (Tr. 12, at 1303; RR-DPU-45). In response to these events, the Company has undertaken steps to address manhole disturbances, including expanding its replacement of manhole covers with energy release cover (Tr. 12, at 1303-1309; RR-DPU-46). The Department finds, while NSTAR Electric should continue to take proactive steps to maintain an adequate level of manhole safety inspections and continue to install new monitoring and safety technologies, the Company's handling of manhole safety does not constitute a systemic service quality shortcoming. The Department also notes the absence of any evidence of systemic service quality shortcomings that warrant a downward adjustment to NSTAR Electric's allowed ROE. Based on the record and balancing the Company's service quality record, the Department concludes that NSTAR Electric's qualitative factors justify an allowed ROE above the midpoint of the reasonable range.

g. Investment Risk

The Attorney General states, and the Department has held, that credit ratings provide investors with relevant information with respect to a company's risk level (Exh. AG-JRW-1, at 6, 24). D.P.U. 20-120, at 396. Nonetheless, debt and equity securities are exposed to different risks and, therefore, require different returns. D.P.U. 20-120, at 396. Therefore, while credit ratings alone do not reflect the full range of risk borne by equity investors, it would be reasonable for investors to consider a company's credit rating in the assessment of investment risk. D.P.U. 20-120, at 396. NSTAR Electric has not provided any persuasive evidence that investors would not rely on credit ratings in the assessment of investment risk, and we reaffirm our previous findings.

The Attorney General also contends that NSTAR Electric has lower investment risk because the Company's equity ratio is higher than the average equity ratios of the proxy groups (Exh. AG-JRW-1, at 30). Credit rating agencies take a company's capital structure into account in their ratings (see e.g., Exh. AG-1-11, Att. (a) at 18, Att. (d) at 7 (Supp.) (liquidity analysis includes company's management of its capital structure)). Therefore, the Department concludes that separate adjustments to the allowed ROE for NSTAR Electric's credit rating and NSTAR Electric's capital structure would overstate the impact of the Company's capital structure on its investment risk.

The Department has found that a PBR plan's more timely and flexible cost recovery serves to reduce a company's risks while a stay-out provision as part of a PBR plan may increase a company's risks in meeting its financial requirements. D.P.U. 20-120, at 431-432; D.P.U. 19-120, at 405-405; D.P.U. 18-150, at 494-495; D.P.U. 17-05, at 710-711. The Department has established in this Order a PBR plan specific to the Company. As described Section IV.D.5 above, the PBR plan allows NSTAR Electric to implement annual rate adjustments to provide revenue support for post-test-year expense increases and capital investments and includes an exogenous cost provision. The Department, however, also has approved a five-year stay-out provision (see Section IV.D.5.a. above).

Above, the Department found that NSTAR Electric's ROE should be in the upper half of the reasonable range because of extraordinary market conditions and the Company's qualitative factors. Based on a balancing of the provisions of the PBR plan approved in this Order and NSTAR Electric's credit rating relative to the proxy groups, the Department finds that NSTAR Electric's allowed ROE should be at the lower-end of the upper half of the reasonable range.

4. Conclusion

Based on a review of the evidence presented in this case, the arguments of the parties, and the considerations set forth above, the Department finds that an authorized ROE of 9.80 percent is within a reasonable range of rates that will preserve NSTAR Electric's financial integrity, will allow it to attract capital on reasonable terms and for the proper discharge of its public duties, will be comparable to earnings of companies of similar risk and, therefore, is appropriate in this case.[194] In making this finding, the Department has exercised its expertise and informed judgment and has considered both qualitative and quantitative aspects of the parties' various methods for determining the Company's ROE, as well as the arguments of and evidence presented by the parties in this proceeding.

XVII. RATE STRUCTURE

A. Rate Structure Goals

Rate structure defines the level and pattern of prices charged to each customer class for its use of utility service. The rate structure for each rate class is a function of the cost of serving that rate class and how rates are designed to recover the cost to serve that rate class. The Department has determined that the goals of designing utility rate structure are to achieve efficiency and simplicity as well as to ensure continuity of rates, equity and fairness between rate classes, and corporate earnings stability. D.P.U. 19-120, at 409; D.P.U. 17-170, at 313; G.L. c. 25, § 1A.

Efficiency means that the rate structure should allow a company to recover the cost of providing the service and provide an accurate basis for consumers' decisions about how to best fulfill their needs. The lowest-cost method of fulfilling consumers' needs should also be the lowest-cost means for society as a whole. Thus, efficiency

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[194] In setting this ROE, the Department has taken into consideration the amount of the storm fund assessment paid by the Company pursuant to G.L. c. 25, § 18. See Fitchburg Gas and Electric Light Company et al. v. Department of Public Utilities, 467 Mass. 768 (2014).

in rate structure means it is cost based and recovers the cost to society of the consumption of resources to produce the utility service. D.P.U. 19-120, at 409; D.P.U. 17-170, at 313-314.

The Department has determined that a rate structure achieves the goal of simplicity if it is easily understood by consumers. Rate continuity means that changes to rate structure should be gradual to allow consumers time to adjust their consumption patterns in response to a change in rate structure. In setting rates, the Department balances fairness and equity. Fairness means that each customer class should pay more than the costs of serving that class. Equity, in rate structure, means that the Department considers affordability among customers in establishing rate classes and when establishing discount rates for low-income customers.[195] Earnings stability means that the amount a company earns from its rates should not vary significantly over a period of one or two years. D.P.U. 19-120, at 409-410; D.P.U. 17-170, at 314; G.L. c. 25, § 1A.

There are two parts to determining rate structure: cost allocation and rate design. The cost allocation step assigns a portion of a company's total costs to each rate class through an embedded ACOSS. The allocated cost of service represents the cost of serving each rate class at equalized rates of return ("EROR") given the company's level of total costs. D.P.U. 19-120, at 410; D.P.U. 17-170, at 314.

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[195] The Department addresses the low-income discount rate and compliance with G.L. c. 164, § 141 in Section XVII.C.3 below.

There are four steps to develop an ACOSS. The first step is to functionalize costs. In this step, costs are associated with the production, transmission, or distribution function of providing service. The second step is to classify expenses in each functional category according to the factors underlying their causation. Thus, the expenses are classified as demand-, energy-, or customer-related. The third step is to identify an allocator that is most appropriate for costs in each classification within each function. The fourth step is to allocate all of a company's costs to each rate class based upon the cost groupings and allocators chosen and then to sum for each rate class the costs allocated in order to determine the total costs of serving each rate class at EROR. D.P.U. 19-120, at 410; D.P.U. 17-170, at 315.

The results of the ACOSS are compared to normalized revenues billed to each rate class in the test year. If these amounts are reasonably comparable, then the revenue increase or decrease may be allocated among the rate classes to equalize the rates of return and ensure that each rate class pays the cost of serving it. If, however, the differences between the allocated costs and the test-year revenues are significant, then, for reasons of continuity, the revenue increase or decrease may be allocated so as to reduce the difference in rates of return, but not to equalize the rates of return in a single step. D.P.U. 19-120, at 411; D.P.U. 17-170, at 315.

As the previous discussion indicates, the Department does not determine rates based solely on the results of an ACOSS, but also explicitly considers the effect of its rate structure decisions on the amount that customers are billed. For instance, the pace at which fully cost-based rates are implemented depends, in part, on the effect of the changes on customers. In addition, considering the goal of equity, the Department also has ordered the establishment of special rate classes for certain low-income customers and has considered the effect of such rates and rate changes on low-income customers.[196] D.P.U. 19-120, at 411; D.P.U. 17-170, at 316; G.L. c. 25, § 1A. To reach fair decisions that encourage efficient utility and consumer actions, the Department's rate structure goals must balance the often-divergent interests of various customer classes and prevent any class from subsidizing another class unless a clear record exists to support such subsidies – or unless such subsidies are required by statute, e.g., G.L. c. 164, § 1F(4)(i) (discounted low-income rates). In addition, G.L. c. 164, § 94I ("Section 94I") requires the Department, in each base distribution rate proceeding, to design rates based on EROR by customer class as long as the resulting impact for any one customer class is not more than ten percent.[197] The

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[196] By enacting G.L. c. 164, § 1F(4)(i), the Legislature substantially adopted the Department's structure, eligibility requirements, and rules governing discounted rates for low-income customers of electric and gas companies.

[197] Section 94I provides:

> In each base distribution rate proceeding conducted by the [D]epartment under Section 94, the [D]epartment shall design base distribution rates using a cost-allocation method that is based on equalized rates of return for each customer class; provided, however, that if the resulting impact of employing this cost-allocation method for any [one] customer class would be more than [ten] percent, the [D]epartment shall phase in the elimination of any cross subsidies between rate classes on a revenue neutral basis phased in over a reasonable period as determined by the [D]epartment.

Department reaffirms its rate structure goals that are designed to result in rates that are fair, equitable, and cost-based and enable customers to adjust to changes. D.P.U. 19-120, at 412; D.P.U. 17-170, at 316-317.

The second part of determining the rate structure is rate design. The level of the revenues generated by a given rate structure is governed by the cost allocated to each rate class in the cost allocation process. The pattern of prices in the rate structure, which produces the given level of revenues, is a function of the rate design. The overarching requirement for rate design is that a given rate class should produce sufficient revenues to cover the cost of serving the given rate class and, to the extent possible, meet the Department's rate structure goals discussed above. D.P.U. 19-120, at 412; D.P.U. 17-170, at 317.

B. Allocated Cost of Service Study and Rate Design

1. Introduction

NSTAR Electric currently consists of four legacy operating companies. They are Boston Edison Company ("Boston Edison"), Cambridge Electric Light Company ("Cambridge Electric Light"), Commonwealth Electric Company ("Commonwealth Electric") and WMECo (Exh. ES-RDC-1, at 2). In its previous base distribution rate case filing, D.P.U. 17-05, the Company filed a proposal to consolidate and align the rates and rate classes associated with its Boston Edison, Cambridge Electric Light, Commonwealth Electric, and WMECo operating companies into two sets of rates; Boston Edison, Cambridge Electric Light, and Commonwealth Electric rates comprised the EMA rate classes, and the WMECo rates comprised the WMA rate classes (Exh. ES-RDC-1, at 2-3). The proposal envisioned the consolidation of existing customers under a single set of tariffs for EMA and WMA territories, with separate distribution pricing for customers in EMA and in WMA, but consolidated transmission rates and certain reconciling rates (Exh. ES-RDC-1, at 3). The Department allowed certain components of NSTAR Electric's previous rate consolidation and alignment plan, but we did not accept the Company's entire plan and directed the Company to undertake a gradual implementation of a consolidated and aligned rate design for general service customers to ameliorate large bill impacts without a multi-year subsidy plan, to improve unclear tariffs, and to comply with Section 94I (Exh. ES-RDC-1, at 4). D.P.U. 17-05, at 96. Moreover, the Department encouraged the Company to provide for a more gradual plan for consolidation and alignment either through its next general rate filing or through a revenue neutral rate design filing(s) (Exh. ES-RDC-1, at 4). D.P.U. 17-05-B at 96.

In the current filing, the Company proposes to streamline and align its rate offerings for possible future consolidation or simplification (Exh. ES-RDC-1, at 5). The Company's proposal addresses the ACOSS, rate consolidation, distribution rate design, transmission rate allocation and design, reconciliation rate allocation factors, and revised LED streetlight pricing. Each of these areas is addressed below.

2. ACOSS

a. Company Proposal and Updates

NSTAR Electric performed an ACOSS that assigns or apportions, based on cost-causation principles, the Company's total cost of service to each rate class (Exh. ES-ACOS-1, at 5). NSTAR Electric developed its ACOSS using five main steps (Exh. ES-ACOS-1, at 6-7). First, the Company functionalized its rate base and costs into the main functions required to provide electricity to customers (Exh. ES-ACOS-1, at 7). NSTAR Electric followed the functional categories contained in the FERC Uniform System of Accounts ("USOA-FERC"),[198] which are production, transmission, distribution, customer services, and administrative and general (Exh. ES-ACOS-1, at 7).

Second, the Company performed a levelization of costs, which involves the disaggregation of costs by customers' voltage service levels, or voltage "splits" (Exh. ES-ACOS-1, at 7). The service level designations are a means of identifying and associating investment and expenses with customers and their loads at established points of service (Exh. ES-ACOS-1, at 7). The levelization is performed because typically, the lower the voltage level of service required by the customer, the greater the cost to provide service (Exh. ES-ACOS-1, at 7). The Company applied voltage splits using an analysis developed for the marginal cost study submitted in the Company's last base distribution rate case, D.P.U. 17-05 (Tr. 8, at 789). The marginal cost study was prepared in 2015 and encompassed year-by-year plant additions by FERC account for the 30-year period of 1986 through 2015 (Exh. CLC-ES 3-6, Att. (h) (Supp. 2)).

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[198] 18 CFR Part 1.

Third, the Company classified the functionalized and levelized costs into three primary "cost-causative" characteristics of investment and expenses (Exh. ES-ACOS-1, at 8). Each type of cost varies in response to changes in one or more of three categories: energy consumed (kWh), peak demand (kilowatt ("kW")), and number of customers (Exh. ES-ACOS-1, at 8).

Next, once the costs are classified, they were assigned to the group or groups of customers responsible for those costs (Exh. ES-ACOS-1, at 8). Finally, in the fifth step, the Company developed allocators to allocate common costs (costs that cannot be assigned to specific customers) among the rate groups (Exh. ES-ACOS-1, at 8).

The Company used 24 rate classes in the ACOSS study (Exh. ES-ACOS-1, at 8). The rate classes were mostly denominated as Residential and General Service, with differentiation of the former group by whether the customer has electric space heating, and of the latter group by legacy service area and by size, as defined by billing demand (Exh. ES-ACOS-1, at 8). Additional rate classes included two sets of streetlight customers, differentiated by equipment ownership (i.e., Company or customer) (Exh. ES-ACOS-1, at 8).

As discussed in further detail below, the Company proposed to consolidate some rate classes within its legacy service areas and to create improved alignment of rate class definitions across the service areas (Exh. ES-ACOS-1, at 9). The Company states that in implementing the consolidation and alignment, the ACOSS faced the challenge that the rate classes defined for the study are prospective, using rate class definitions submitted for approval in this filing (Exh. ES-ACOS-1, at 9). Several of the definitions differ from their predecessors, so the Company estimated customer numbers, peak demand, and energy consumption for the newly defined classes based upon numbers for the current classes (Exh. ES-ACOS-1, at 9).

On May 13, 2022, the Company filed its first revised ACOSS and rate design exhibits (Exhs. ES-ACOS-2 through ES-ACOS-5 (Rev. 1); ES-RDC-2 through ES-RDC-5 (Rev. 1); ES-RDC-7 (Rev. 1)). In these revised exhibits, the Company: (1) updated test-year billing determinants from 2020 to 2021 quantities; (2) updated the test-year revenue requirement to reflect the Company's revisions in its April 22, 2022 filing; (3) restricted revenue allocations to residential customers per the Department's directive in D.P.U. 20-120, at 485, and as discussed in the Company's prefiled testimony; and (4) revised the low-income discount from 36 percent to 42 percent (Exhs. ES-RDC-1, at 36-39; ES-ACOS-2 through ES-ACOS-5 (Rev. 1); ES-RDC-2 through ES-RDC-5 (Rev. 1); ES-RDC-7 (Rev. 1); LI-ES 1-4; LI-ES 1-5).

On July 1, 2022, the Company filed a second revised ACOSS and rate design exhibits to reflect another revenue requirement update filed earlier on June 24, 2022 (Exhs. ES-ACOS-2 through ES-ACOS-5 (Rev. 2); ES-RDC-2 through ES-RDC-5 (Rev. 2); ES-RDC-7 (Rev. 2)). In these revised exhibits, the Company: (1) corrected customer counts related to the existing WMA Rate T-4, and proposed WMA Rates G-1 and T-4; (2) updated primary and secondary voltage splits; and (3) updated the weighting favors for customer assistance and sales (Exhs. ES-ACOS-2 through ES-ACOS-5 (Rev. 2); ES-RDC-2 through ES-RDC-5 (Rev. 2); ES-RDC-7 (Rev. 2); CLC-ES 3-6 Att. (h) (Supp. 3)). Regarding the voltage splits, the Company applied a new method to determine voltage level line items based on more recently calculated 2020 values and provided an explanation of how the primary voltage level line items were determined (Exh. CLC-ES 3-6, Att. (h) (Supp. 3); Tr. 8, at 788-792). As noted above, in its initial ACOSS, the Company applied values used in its previous rate filing, D.P.U. 17-05 (Exh. CLC-ES 3-6, Att. (h) (Supp. 2); Tr. 8, at 789).

On July 22, 2022, in response to a record request issued at the evidentiary hearings by Cape Light Compact, the Company updated its second revised ACOSS (RR-CLC-3). In this response, the Company provided (i) an explanation and supporting documentation for the classification criteria used in the engineering assessment to classify retirement units for each plant account listed in Exhibit CLC-ES-3-6 Att. (h) (Supp. 3), which had been filed on July 12, 2022, and (ii) an update to voltage split information used in second revised ACOSS filed on July 1, 2022. As part of its response to Record Request CLC-3, the Company updated its second revised ACOSS, reflecting values from Exhibit CLC-ES-3-6 Att. (h) (Supp. 3), and inclusive of corrections to errors identified while responding to Record Request CLC-4 through Record Request CLC-6 (RR-CLC-3, Att. (d)).

On September 27, 2022, the Company filed a third revised ACOSS and rate design exhibits to reflect another revenue requirement update, which was filed on the same day (Exhs. ES-ACOS-2 through ES-ACOS-5 (Rev. 3); ES-RDC-2 through ES-RDC-5

(Rev. 3)).[199] Additionally, in this version of the ACOSS, the Company incorporated all of the changes it identified in responding to Record Request CLC-3 as discussed above (i.e., provided documentation and explanation for the classification criteria used in the engineering assessment to classify retirement units for each plant account, further updated voltage splits as provided in its second revised ACOSS filed on July 1, 2022, and corrected errors identified while responding to other record requests) (RR-CLC-3, Att. (d); RR-CLC-4; RR-CLC-5; RR-CLC-6; see Exh. CLC-ES 3-6, Att. (h) (Supp. 3)).

b. Positions of the Parties

i. Attorney General

The Attorney General challenges certain methods employed by the Company regarding cost allocation. Specifically, the Attorney General argues that the change of allocations between the first revised and second revised ACOSSs and between the second revised ACOSS and the Company's response to Record Request CLC-3, are significant and provided limited opportunity for Department and intervenor review (Attorney General Brief at 157-158). The Attorney General also asserts that NSTAR Electric's data is deficient, and that the Company does not have a complete understanding of the basis for the updated voltage allocations being applied in the most recent versions of the ACOSS (Attorney General Brief at 155, 158).

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[199] The final revenue requirement shown in Exhibit ES-REVREQ-2 is slightly lower than the revenue requirement used to develop the rate design exhibits due to the timing of the debt issuance reflected in the cost of service.

The Attorney General asserts that the Department should require NSTAR Electric to use the original filed voltage splits reflective of the values used in its last base distribution rate case (Attorney General Brief at 158). The Attorney General also asserts that the Department should require that the Company include a comprehensive and thorough distribution plant voltage analysis as part of its initial filing in its next base distribution rate case (Attorney General Brief at 158-159).

ii. Cape Light Compact

Cape Light Compact supports the Company's corrections in its second revised ACOSS filing as well as the ACOSS filed as the Company's response to Record Request CLC-3, Att. (d) (CLC Brief at 18). Cape Light Compact also agrees with the updates made to reflect corrected primary and secondary share assignments as well as the change in method used by the Company to classify primary and secondary voltage splits using 2020 data (CLC Brief at 19, 21; CLC Reply Brief at 5). In addition, Cape Light Compact agrees with the changes to weighting factors updated for customer assistance and sales in the Company's second revised ACOSS (CLC Brief at 22).

Cape Light Compact, however, disagrees with the Company's use of amalgamation of primary shares for accounts 364 and 365, and for accounts 366 and 367 (CLC Brief at 23; CLC Reply Brief at 9-10). Cape Light Compact argues that the Company's use of amalgamation to assign weights to primary and secondary customers for these accounts should be rejected because it results in arbitrary cost allocation and unjustified cost shifts among rate classes (CLC Brief at 23; CLC Reply Brief at 9-10). Cape Light Compact also contends that amalgamated shares do not result in accurate cost allocation, are entirely unnecessary to avoid volatility between rate cases, and result in unjustified cost shifts between rate classes (CLC Brief at 23, 26-27). Cape Light Compact asserts that the Department should reject the Company's amalgamated shares for accounts 364 and 365, and for accounts 366 and 367, and recommends that the Department direct the Company to produce an updated ACOSS model to reflect this change (CLC Brief at 27-28).

iii. Company

NSTAR Electric rejects the notion that the data used to develop the voltage splits is deficient, and the Company contends that the categorization of its assets begins with the WAM System where individual work orders are created (Company Brief at 423). NSTAR Electric asserts that completed work orders that have met all work-management requirements are then classified based on a combination of guidance from the Company's Capital vs. Expense Policy ("APS#8"), the USOA-FERC, and the Company's retirement unit manual (Company Brief at 423, citing RR-CLC-3, Atts. (a) & (b); RR-CLC-4, Att. 4(c)). NSTAR Electric also claims that APS#8 lays out guidelines as to when assets may be capitalized, and the USOA-FERC and Company's retirement unit manual illustrate the types of assets that are capitalized in each plant account (Company Brief at 423, citing RR-CLC-3). According to NSTAR Electric, however, voltage information is not available in these plant records so Company engineers must use their knowledge and expertise to review the listed retirement units in each account in assessing their application for primary versus secondary service (Company Brief at 423, citing RR-CLC-3). Finally, the Company asserts that in its review of assets in accounts 365-368 it found erroneous assignments, and that it corrected these errors in the ACOSS model filed in response to Record Request CLC-3 (Company Brief at 424, citing RR-CLC-3 through RR-CLC-6).

NSTAR Electric also affirms its decision to use updated voltage allocations of distribution plan assets booked to FERC Accounts 366 and 367 in its second and third revised ACOSS (Company Brief at 422-423). The Company argues that its late-stage voltage split allocation update was appropriate, as it was first filed in response to a record request issued by Cape Light Compact and was based on the test year rather than extending the time series analysis or continuing using the historical method to allocate voltage splits as approved in D.P.U. 17-05 (Company Brief at 423, citing RR-CLC-2; RR-CLC-3).

Further, NSTAR Electric argues that its use of amalgamation of primary shares is consistent with Department precedent, in particular the Company's previous ACOSS approved in D.P.U. 17-05 (Company Brief at 418, 422; Company Reply Brief at 56-57). The Company also contends that using amalgamated shares is supported by the National Association of Regulatory Utility Commissioners ("NARUC") Cost of Service manual, particularly for Accounts 366 and 367 (Company Brief at 418, 422, citing NARUC manual at 91). Further, the Company asserts that Account 365 represents overhead conductors and devices that must be attached to the poles and towers recorded in Account 364, and therefore the primary voltage shares for those two accounts are set equal (Company Brief at 422, citing D.P.U. 17-05). In addition, the Company argues that it would be inappropriate to classify all poles as primary because poles that carry both primary and secondary lines are often classified as primary, while poles that carry secondary lines are classified as secondary (Company Brief at 422, citing D.P.U. 17-05). Therefore, NSTAR Electric concludes that changing the Company's accounting and separating the calculations for Accounts 364 and 365 would be inconsistent with Department precedent (Company Brief at 422, citing D.P.U. 17-05).

c. Analysis and Findings

First, the Department addresses the Company's updated ACOSS filings. The Company explained during evidentiary hearings the significance of accurately classifying assets to the correct account and between primary service and secondary service customers:

> The primary and secondary splits occur for the distribution asset accounts, or rate-base accounts, typically 364 to 368 under the FERC accounting system. And the purpose of the splits is to ensure that costs are allocated to customer groups that actually make use of the assets. So, one would want a primary-level customer not to be responsible for secondary-level costs. So, for each of these main distribution accounts, 364 to 368, the effort is made in typical rate cases and in this one to determine the share of assets that serves primary only and the share of assets that serves secondary or primary and secondary.
> (Tr. 8, at 783).

The Company, therefore, acknowledges that it is charged with tracking costs to each distinct account, and accurately splitting the shares of those costs between primary service and secondary service customers.

For concerns related to continuity and fairness, the Company should have a clear process by which it assigns and allocates costs across accounts and customers. The Department and intervenors need the opportunity in a base distribution rate case to examine the procedures and data behind the calculations. In the instant case, however, the Company, without explanation or support, filed, concurrent with its submission, new allocations and voltage splits in its second ACOSS, response to Record Request CLC-3, and third revised ACOSS, after the discovery period for this case closed. While the Company states that the values used in its revised ACOSSs are based on data that was not previously available (Tr. 8, at 790), the Department cannot find that such data has been adequately reviewed for consistency and accuracy. Absent clear, replicable processes or procedures documented to explain how the Company approaches the assignment and allocation of costs to primary service and secondary service customers for these accounts, the Department directs the Company to utilize the costs and voltage splits used in its initial filing (i.e., the data used in D.P.U. 17-05) in its current cost allocation process. In addition, the Department directs NSTAR Electric to undertake a review of the processes used to assign costs to individual accounts and primary service and secondary service customers and to report on the results of the review in the Company's initial filing in its next base distribution rate case.

Cape Light Compact expresses concerns with the Company's use of amalgamation for Accounts 364 and 365, as well as for Accounts 366 and 367, when assigning the revenue requirement associated with those accounts to primary service and secondary service customer rate classes (CLC Brief at 23; CLC Reply Brief at 9-10). Cape Light Compact argues that the Company's use of amalgamation to assign weights to primary and secondary customers for these accounts should be rejected because it results in arbitrary cost allocation and unjustified cost shifts among rate classes (CLC Brief at 23; CLC Reply Brief at 9-10). The Company does not claim that it is incapable of producing costs by account, or incapable of properly assigning them by voltage split; it simply contends that such practice was used in the prior rate filing, D.P.U. 17-05, and that share combinations are supported by the NARUC Cost of Service manual (Company Brief at 418, 422). Absent a lack of data, information, or other rationale pertaining to the actual data available, the Department is not persuaded that the continued amalgamation of Accounts 364 and 365, as well as Accounts 366 and 367, is necessary. The Company has distinct cost data for these accounts, which, by definition, will lead to more accurate cost allocation as it will accurately apply the principle of cost causation (Tr. 8, at 793). Further, we find that the Company has not provided analysis or sufficient information to convince us that amalgamation of voltage splits is necessary to avoid rate volatility (Exh. CLC-ES 3-6, Att. (h) (Supp. 2)). Additionally, our prior approval of amalgamating certain costs does not preclude us from reaching a different finding here, particularly where amalgamation was not raised as a contested issue in D.P.U. 17-05 and, as we do here, we explain the reason for our decision. United Automobile Workers v. National Labor Relations Board, 802 F.2d 969, 974 (1986); D.P.U. 20-120, at 325 n.158. Therefore, the Department directs the Company not to use amalgamation of accounts for which distinct detail exists and to file a revised ACOSS in compliance with this directive.

3. Rate Consolidation and Revenue Allocation

a. Introduction

The Company proposes to eliminate obsolete rate offerings, partially consolidate and align tariffs, and simplify existing rate designs (Exh. ES-RDC-1, at 5). In addition, the

Company proposes to refine certain tariff definitions, introduce a non-demand small C&I offering within Rate G-1, and eliminate or alter seasonal and time-of-use ("TOU") rates (Exh. ES-RDC-1, at 5).

The current rate groupings for C&I customers, which are born from legacy classifications, are classified differently, and assigned significantly different rate designs, which the Company states makes it difficult to consolidate rate classes without triggering unacceptable bill impacts (Exh. ES-RDC-1, at 17). For example, Cambridge Electric Light Rate G-2 includes customers with monthly demands greater than 100 kW, and these customers are categorized as medium/large general service customers; however, in WMA, customers with monthly demands up to 349 kW are categorized as small general service customers (Exh. ES-RDC-1, at 17). As the Company pursues consolidation among its legacy rate classes, the categorization of various classes is significant to ensure that customers are treated equitably across the Company's entire operating territory (Exh. ES-RDC-1, at 17).

NSTAR Electric states that it is not proposing entirely new rate classes, rather it is proposing new names and alternative definitions for some rate classes (Exh. ES-RDC-1, at 21). To establish consistency and simplicity, the Company proposes to establish: (1) Rate G-1 as its rate class for customers with demand annually equal to or less than 100 kW; (2) Rate G-2 for customers with demand annually greater than 100 kW; (3) Rate G-3 for customers with large loads who frequently receive service at the primary voltage level; and (4) WMA Rate T-5, which is unique to WMA and which serves a small number of customers (Exh. ES-RDC-1, at 21).

For small C&I customers, the Company proposes to introduce a common threshold throughout its service territory (Exh. ES-RDC-1, at 19). Currently, the demand threshold for Boston Edison Rate G-1 is 10 kW, Cambridge Electric Light Rate G-1 and Commonwealth Electric Rate G-1 is 100 kW, and WMA Rate G-0 is 349 kW (Exh. ES-RDC-1, at 19). The Company states that the most efficient and least disruptive way to establish consistency among customers is to adopt one of the existing demand thresholds (Exh. ES-RDC-1, at 19). Therefore, the Company chose a 100-kW demand threshold for small C&I customers (Exh. ES-RDC-1, at 19).[200]

The Company also proposes to introduce a new non-demand offering for small C&I customers under the proposed G-1 rate class (Exh. ES-RDC-1, at 5, 41). NSTAR Electric states that the non-demand offering and the Company's general attention toward energy-only rates for small C&I customers are in response to the evolving nature of rate design considering public policy, technology, and ever-shifting customer uses, such as electric vehicle charging (Exh. ES-RDC-1, at 42).

Further, the Company proposes to eliminate seasonal pricing in the Boston Edison service area, except for customers taking service under Rate T-1, because such pricing potentially results in higher bills in the summer through a combination of higher rates and

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[200] The Company also proposes to allow customers to take service on Rate G-2 if their average monthly demand over 12 consecutive months – rather than their monthly demand – exceeds 100 kW (RR-TEC-1).

usage (Exh. ES-RDC-1, at 41-42). The Company states that elimination of the summer price differential will provide some rate relief to customers (Exh. ES-RDC-1, at 41-42).

The Company also proposes that rate classes and customers falling into the medium general service category that build on the definitions established for small general service rate classes and the existing definitions for large general service rate classes (Exh. ES-RDC-1, at 19-20). As such, customers using more than 100 kW annually that are not otherwise assigned to a large general service rate class are considered medium general service customers (Exh. ES-RDC-1, at 20). The Company states that it is not proposing revisions to rate class definitions in the large general service category at this time, as the legacy class differences are not as significant as those seen in the small general service group (Exh. ES-RDC-1, at 20).

More specifically, the Company proposes: (1) expanding the Boston Edison Rate G-1 offering from 10 kW to 100 kW; (2) moving the current Boston Edison Rate G-2 customers to either the expanded Boston Edison Rate G-1or Boston Edison Rate T-2; (3) renaming the Boston Edison Rate T-2 as Boston Edison Rate G-2 and changing the availability from greater than ten kW to greater than 100 kW; (4) combining Cambridge Electric Light Rates G-0, G-1, and G-4 into Cambridge Electric Light Rate G-1 that encompasses customers with monthly demand up to 100 kW, and cancel Cambridge Electric Light Rates G-0 and G-4; (5) consolidating Commonwealth Electric Rate G-5 customers into new Commonwealth Electric Rate G-1; (6) closing Commonwealth Electric Rate G-7; (7) consolidating WMA Rate G-0, WMA Rate T-0, WMA Rate G-2, and WMA Rate T-4 with monthly demand up to 100 kW into a new WMA Rate G-1; (8) moving the remaining WMA Rate G-0, WMA Rate T-0, and WMA Rate G-2 customers with demand greater than 100 kW to revised WMA Rate G-2 with monthly demand greater than 100 kW and up to 349 kW, thereby eliminating WMA Rate T-0; (9) limiting WMA Rate T-4 to monthly demand greater than 100 kW and up to 349 kW; and (10) renaming WMA Rate T-2 as WMA Rate G-3 (Exh. ES-RDC-1, at 20, 71-72).

The Company also proposes to eliminate use of the declining block rate/demand charge design and, where appropriate, that the rate design would be replaced by a simple customer charge/energy charge design with no demand charge or demand ratchets (Exh. ES-RDC-1, at 8-9). The Company states that elimination of the current energy block design will improve the price signal to ratepayers of the cost of energy at the margin (Exh. ES-RDC-1, at 42). In addition, the Company proposes to maintain block demand charges, or demand ratchets only on those rates where there are continuity concerns (Exh. ES-RDC-1, at 10-11).

The Company states that currently effective optional TOU rate offerings have been closed for new customer enrollment, with the exception for Cambridge Electric Light Rate G-4, Commonwealth Electric Rate G-7, WMA Rate T-0, and WMA Rate T-4 (Exh. ES-RDC-1, at 11). The Company proposes to transfer Cambridge Electric Light Rate G-4 customers to the proposed Cambridge Electric Light Rate G-1, close Commonwealth Electric Rate G-7, and consolidate WMA Rate T-0 customers into proposed

WMA Rate G-1 (Exh. ES-RDC-1, at 11). In addition, the Company proposes to redefine WMA Rate T-4 (Exh. ES-RDC-1, at 11).

Finally, the Company states that it is not introducing new TOU energy rates at this time, as it asserts that volumetric TOU rates are not appropriate as distribution system costs are primary demand related (Exh. ES-RDC-1, at 11). The Company notes that the current optional TOU rate offerings are vestiges of electric deregulation and that that new TOU rate design would be addressed following the deployment of AMI (Exh. ES-RDC-1, at 11-12, citing Investigation into Time Varying Rates, D.P.U. 14-04-C at 2 (2014); Rulemaking Pursuant to Executive Order 562 to Reduce Unnecessary Regulatory Burden, D.P.U. 15-183 (2016); D.P.U. 1720.

The table below summarizes the Company's current and proposed rate classes and categories:

Rate Group	**Rate Class – current**	**Rate Class - proposed**
Residential (no changes)	Rates R-1, R-2, R-3, and R-4	Rates R-1, R-2, R-3, and R-4
Small General Service	Boston Edison: Rate G-1 (< =10 kW) Rate T-1 (< =10 kW TOU) Rate G-2 (> 10 kW) Cambridge Electric Light: Rate G-0 (< =10 kW) Rate G-6 (< =10 kW TOU) Rate G-1 (10< kW< =100) Rate G-4 (10< kW< =100 TOU) Rate G-5 (Comm. Space Heat) Commonwealth Electric: Rate G-1 (< =100 kW) Rate G-7 (< =100 kW TOU)	Boston Edison: Rate G-1 (< =100 kW) Rate T-1 (< =10 kW TOU) Cambridge Electric Light: Rate G-1 (< =100 kW) Rate G-6 (< =10 kW TOU) Rate G-5 (Comm. Space Heat) Commonwealth Electric: Rate G-1 (< =100 kW) Rate G-7 (< =100 kW TOU) Rate G-4 (General Power)

	Rate G-4 (General Power) Rate G-5 (Comm. Space Heat) Rate G-6 (All-Electric School) WMA: Rate 23 (Water Heating) Rate 24 (Church) Rate G-0 (<= 349 kW) Rate T-0 (<= 349 kW TOU)	Rate G-6 (All-Electric School) WMA: Rate 23 (Water Heating) Rate 24 (Church) Rate G-1 (<= 100 kW)
Medium General Service	Boston Edison: Rate T-2 (> 10 kW) Cambridge Electric Light: Rate G-2 (> 100 kW) Commonwealth Electric: Rate G-2 (100< kW <=500) WMA: Rate G-2 (<=349 kW; Primary) Rate T-4 (<=349 kW; Primary TOU)	Boston Edison: Rate G-2 (>100 kW) Cambridge Electric Light: Rate G-2 (> 100 kW) Commonwealth Electric: Rate G-2 (100< kW <=500) WMA: Rate G-2 (<=349 kW; Primary) Rate T-4 (<=349 kW; Primary TOU)
Large General Service (no changes)	Boston Edison: Rate G-3 (14 kV) Rate WR (MWRA) Cambridge Electric Light: Rate G-3 (>100 kW; 13.8 kV) Rate SB1/MS1/SS1 (MIT Standby) Commonwealth Electric: Rate G-3 (>500 kW) WMA: Rate T-2 (349< kW <= 2500) Rate T-5 (> 2500 kW)	Boston Edison: Rate G-3 (14 kV) Rate WR (MWRA) Cambridge Electric Light: Rate G-3 (>100 kW; 13.8 kV) Rate SB1/MS1/SS1 (MIT Standby) Commonwealth Electric: Rate G-3 (>500 kW) WMA: Rate G-3 (349< kW <= 2500) Rate T-5 (> 2500 kW)
Streetlights (no changes)	Rates S-1, S-2	Rates S-1, S-2

Exh. ES-RDC-1, at 18-19.

a. Positions of the Parties

i. Attorney General

The Attorney General argues that the Department should reject the Company's proposed elimination of seasonal and TOU rates and establish more efficient TOU windows without delay (Attorney General Brief at 171-173). The Attorney General asserts that the Company has not presented a viable reason to eliminate or reduce the availability of seasonal or TOU rates, and she contends that the implementation of new TOU rates could take several years to complete (Attorney General Brief at 173). In addition, the Attorney General claims that the Company's proposal to eliminate seasonal and TOU rates is inconsistent with Department policies favoring peak-demand reduction and optimizing benefits associated with alternative rates such as TOU rates (Attorney General Brief at 173, citing D.P.U. 14-04-C at 3). The Attorney General asserts that to maximize benefits associated with existing TOU rates, the Department should establish a more limited on-peak window and pricing ratios (Attorney General Brief at 175, citing Exh. AG-DED-Surrebuttal-1, at 12-17).

ii. DOER

DOES argues that the Company's peak periods for commercial TOU rates send the wrong incentives to commercial customers, conflict with the structure of the "Clean Peak" program and may result in increased curtailments of renewable generation (DOER Reply Brief at 7-8). Further, DOER contends that, while a future proceeding to establish AMI-supported time-varying rates is necessary and will produce new rates, future process is not a reason to avoid modifications to improve existing TOU rates in the current proceeding (DOER Reply Brief at 8).

iii. Acadia Center

Acadia Center argues that the Department should reject the Company's proposed elimination of seasonal and TOU rates and establish more efficient TOU windows, such as revising on-peak hours to include the hours between 3:00 p.m. and 7:00 p.m. on weekdays (Acadia Center Reply Brief at 2-3). Acadia Center also recommends that the Department consider establishing more efficient TOU windows (Acadia Center Reply Brief at 2-3). Finally, Acadia Center asserts that NSTAR Electric's timeline for its proposal to tie revising TOU rates to AMI deployment is "too slow" (Acadia Center Reply Brief at 2-3).

iv. TEC and PowerOptions

TEC and PowerOptions assert that the Company's peak periods for commercial TOU rates must be adjusted to reflect when peak loads occur, which TEC and PowerOptions claim tend to occur over a smaller number of hours than currently reflected in rates (TEC/PowerOptions Brief at 3). TEC and PowerOptions also express concern that customers with interval meters should be able to maintain such meters despite rate consolidation (TEC/PowerOptions Brief at 11). In this regard, TEC and PowerOptions contend that customers with interval meters are able to purchase retail energy based on their actual hourly consumption, and that many such customers have entered into retail energy supply contracts where pricing is based on the availability of interval data (TEC/PowerOptions Brief at 11). As such, TEC and PowerOptions contend that the Department should ensure that customers do not lose the ability to maintain interval meters with the proposed consolidation and streamlined definitions of rates (TEC/PowerOptions Brief at 11). Finally, TEC and PowerOptions assert that the Department should not wait until years after the full deployment of AMI to revise the Company's TOU periods (TEC/PowerOptions Brief at 3; TEC/PowerOptions Reply Brief at 6).

v. UMass

UMass argues that the current definition of on-peak periods used in the Company's distribution rates and tariffs are out of date, they do not accurately reflect when peak conditions occur on the system and, as a result, they send inefficient price signals that discourage efficient use of the grid and they frustrate the Commonwealth's clean energy and climate policies, particularly around investment in and operation of DG (UMass Brief at 30; UMass Reply Brief at 7). UMass asserts that the Department should require that NSTAR Electric revise its on-peak hours for all TOU customers to include the hours between 3:00 p.m. and 7:00 p.m. on weekdays, with all other hours considered off-peak (UMass Brief at 30). UMass also argues that the Company should not wait until deployment of AMI meters to make the recommended change to TOU rates (UMass Brief at 35; UMass Reply Brief at 7).

Further, UMass argues that the Department should direct NSTAR Electric to eliminate demand ratchets in all of its rate designs (UMass Brief at 40). UMass asserts that demand ratchets are misaligned with Department goals and Massachusetts climate policy, are inefficient, and are unfair and complex (UMass Brief at 40-42). UMass contends that demand ratchets place a floor on customers' demand charges, even if those customers draw no power from the grid across all on-peak hours, resulting in inaccurate price signals that do not elicit efficient behavior (UMass Brief at 41-42).

Finally, UMass argues that the Department should not approve the elimination of seasonally differentiated rates (UMass Brief at 45). UMass argues that discontinuing seasonally differentiated rates would be a "step in the wrong direction" with respect to recent legislation (UMass Reply Brief at 8).

vi. Company

The Company argues that its proposals regarding seasonal rates and TOU rates are reasonable and establish consistency (Company Brief at 429; Company Reply Brief at 58). Regarding seasonal rates, NSTAR Electric argues that it is attempting to establish some consistency in its rate design and that the legacy Boston Edison service area is the only area in Massachusetts with seasonal rates (Company Brief at 429, citing Exh. ES-RDC-Rebuttal-1, at 19; Company Reply Brief at 60). Further, the Company asserts that movement away from seasonally differentiated rates is consistent with electrification efforts (Company Brief at 429, citing Exh. ES-RDC-Rebuttal-1, at 19).

With respect to TOU rates, the Company clarifies that it is not seeking to eliminate all TOU rates in this proceeding (Company Brief at 430; Company Reply Brief at 58). Rather, the Company asserts that it is proposing only to end certain optional TOU rates with limited enrollment (Company Brief at 430; Company Reply Brief at 58). Regarding peak period definitions, the Company argues that this proceeding is not the appropriate time to propose changes, and that large bill impacts could result from such a change (Company Brief at 430). The Company contends that any change in TOU definitions will require a change in the pricing and the ratio of peak to off peak pricing (Company Brief at 430, citing Exh. ES-RDC-Rebuttal-1, at 11; Company Reply Brief at 59). According to the Company, a shorter peak window could narrow the revenue collection during peak hours, which would necessitate higher off-peak pricing over a longer window or much higher pricing during the peak hour (Company Brief at 430, citing Exh. ES RDC-Rebuttal-1, at 11; Company Reply Brief at 59). Further, the Company asserts that it will have more information to review alternative rate structures when AMI is fully developed (Company Brief at 430-431; Company Reply Brief at 60).

b. Analysis and Findings

In D.P.U. 17-05-B, at 96, the Department ordered the Company to provide for a more gradual plan for consolidation and alignment in its next general rate filing. The Department supports the eventual goal of consolidation of the Company's rates across its service territory and finds the Company's proposals related to rate class alignment to be a positive step toward achieving one set of rates for the Company. Rate class alignment also allows for greater flexibility to address current and future policy goals and customer needs.

When consolidating rates, the Department has noted that a proposal must consider our rate structure goals of simplicity, efficiency, continuity, equity, fairness, and earnings stability. D.P.U. 17-05-B at 86; D.P.U. 10-55, at 556; G.L. c. 25, § 1A. The proposals related to alignment in the current case speak directly to the rate structure goals of simplicity, efficiency, equity, and fairness, as customers across the Company's service territory will have more consistent rate definitions and offerings.

The Company has proposed to align general service offering demand thresholds (Exh. ES-RDC-1, at 19-20). Customers with average demand below 100 kW annually will generally be served on Rate G-1 (Exh. ES-RDC-1, at 19). Medium C&I customers will primarily be served under Rate G-2 and will be those with demand between 100 kW and 349 kW annually (Exh. ES-RDC-1, at 19). Large C&I customers will primarily be served under Rate G-3 and will be those with demand between 349 kW and 2,500 kW annually. The Large C&I customers are also frequently serviced at the primary voltage level. (Exh. ES-RDC-1, at 21). The Department finds these proposed rate class definitions to be appropriate and, therefore, they are approved.

NSTAR Electric also proposes a new offering within the G-1 rate class; a non-demand-based rate class (Exh. ES-RDC-1, at 5, 41). Such a rate class can provide appropriate price signals to assist new and advancing customer needs, such as electric vehicle charging (Exh. ES-RDC-1, at 42). Therefore, the Department approves the Company's proposed non-demand-based Rate G-1.

The Company also proposes to eliminate the seasonal rate offerings under Commonwealth Electric Rate G-1, and Commonwealth Electric Rate G-7, but maintain the closed seasonal Boston Edison Rate T-1 (Exh. ES-RDC-1, at 41). The Department finds that in order to align with the rest of NSTAR Electric's service territories, the Company's proposal to eliminate the seasonal offerings under Commonwealth Electric Rate G-1 and Commonwealth Electric Rate G-7 is appropriate at this time (Exh. ES-RDC-1, at 41). Therefore, the Department approves the Company's elimination of the seasonal rate offerings under Commonwealth Electric Rate G-1, and Commonwealth Electric Rate G-7. Additionally, the Department accepts the Company's maintaining the closed seasonal Boston Edison Rate T-1.

The Department also finds that the Company's following proposals meet the Department goal of simplicity, further assist in the alignment and consolidation process, and, therefore, are approved: (1) expanding the Boston Edison G-1 rate offering from 10 kW to 100 kW; (2) moving the current Boston Edison G-2 customers to either the expanded Boston Edison Rate G-1 or Boston Edison Rate T-2; (3) renaming the Boston Edison Rate T-2 as Boston Edison Rate G-2 and changing the availability from greater than ten kW to greater than 100 kW; (4) combining Cambridge Electric Light Rates G-0, G-1, and G-4 into Cambridge Electric Light Rate G-1 that encompasses customers with monthly demand up to 100 kW, and cancel Cambridge Electric Light Rates G-0 and G-4; (5) consolidating Commonwealth Electric Rate G-5 customers into new Commonwealth Electric Rate G-1; (6) closing Commonwealth Electric Rate G-7; (7) consolidating WMA Rate G-0, WMA Rate T-0, WMA Rate G-2, and WMA Rate T-4 with monthly demand up to 100 kW into a new WMA Rate G-1; (8) moving the remaining WMA Rate G-0, WMA Rate T-0, and WMA Rate G-2 customers with demand greater than 100 kW to revised WMA Rate G-2 with monthly demand greater than 100 kW and up to 349 kW, thereby eliminating WMA Rate T-0; (9) limiting WMA Rate T-4 to monthly demand greater than 100 kW and up to 349 kW; and (10) renaming WMA Rate T-2 as WMA Rate G-3 (Exh. ES-RDC-1, at 20, 71-72).

Next, the Department finds it reasonable and appropriate to approve the Company's proposal to eliminate the use of block energy rates (Exh. ES-RDC-1, at 8-9). The

Department finds that the Company's proposal to replace the block energy rates with a simple customer charge and energy charge design is consistent with the goal of simplicity.

The Company has reduced, but still maintains, some demand ratchets (Exh. ES-RDC-1, at 45). The Department recognizes that, in some instances, demand ratchets may be misaligned with the goals to establish efficient, fair, and simple rate structures. Further, demand ratchets may conflict with Massachusetts' climate policy and the Department's statutory mandates to prioritize reducing GHG emissions and increasing energy efficiency. Nonetheless, based on continuity concerns, we find it inappropriate to eliminate all demand ratchets in the instant proceeding. Thus, the Company shall retain a demand ratchet for existing customers currently taking service under proposed Boston Edison demand Rate G-1, in which customers with usage greater than 10 kW pay a demand charge but those customers with usage at or under 10 kW do not (Exhs. ES-RDC-1, at 45; ES-RDC-2, Sch. 1, at 1 (Rev. 3)). Similarly, the Company shall retain a demand ratchet for customers taking service under WMA Rate 24, and Commonwealth Electric proposed Rate G-1 demand, in which a demand ratchet is used for existing customers with demand meters and usage above 2 kW (Exhs. ES-RDC-1, at 45; ES-RDC-2, at 1 (Rev. 3)). Further, the Department directs the Company and all EDCs to address the merits of demand ratcheted rates in their next base distribution rate filings, and, if warranted, to include a proposal or plan to eliminate the use of ratcheted rates.

The Company states that all currently effective, optional TOU rates have been closed except for Cambridge Electric Light Rate G-4, Commonwealth Electric Rate G-7, WMA Rate T-0, and WMA Rate T-4 (Exh. ES-RDC-1, at 11). The Company proposes to transfer Cambridge Electric Light Rate G-4 customers to the non-demand, proposed Cambridge Electric Light Rate G-1; close Commonwealth Electric Rate G-7; and consolidate WMA Rate T-0 into the non-demand, proposed WMA Rate G-1 (Exh. ES-RDC-1, at 11). Several intervenors argue that the peak periods should be adjusted, and that the Department need not wait until AMI deployment to do so (Attorney General Brief at 171-173; DOER Reply Brief at 8; Acadia Center Reply Brief at 2-3; TEC/PowerOptions Brief at 3; TEC/PowerOptions Reply Brief at 6; UMass Brief at 35; UMass Reply Brief at 7).

The Department finds that the Company's peak and off-peak hours should be refined, and, for TOU rates, should better reflect actual distribution system demand costs. The current TOU time periods available to the Company's customers are very broad and pre-date electric industry restructuring. The TOU offerings proposed to be eliminated have limited enrollment as well. Nonetheless, we share the Company's concern that adjusting the peak period at this time may be disruptive to ratepayers (Exhs. ES-RDC-Rebuttal-1, at 11; AG 40-4). As such, we find that it is more appropriate to address revised peak periods once the Company has moved forward on AMI implementation and we have more information to review alternative rate structures that will benefit customers and achieve public policy objectives. See, e.g., G.L. c. 164, § 92B (electric sector modernization plans); D.P.U. 21-80-B/D.P.U. 21-81-B/D.P.U. 21-82-B at 201, 327 & n.136. Based on these considerations, we approve the Company's proposal to transfer existing TOU customers to different rate classes, as identified above.

Finally, the Department finds that it is reasonable and appropriate for customers impacted by rate alignment efforts to continue to use interval meters to utilize the competitive retail electricity market. In particular, we recognize that many of these customers have entered into multi-year competitive electricity supply contracts that are predicated upon a load shape informed by interval metering data, and that a switch from interval meter data to a profiled load during a rate consolidation has the potential to disrupt pre-existing electricity supply contractual arrangements (Exh. SUR-TEC/PO-JDB-1, at 12).

4. Distribution Rate Design

a. Introduction

NSTAR Electric proposes to collect $1,261,038,188 in base distribution revenues (Exh. ES-REVREQ-2, Sch. 1 (Rev. 4)). In allocating revenues to rate groups, the Company departed from traditional revenue allocation in that it proposes to first develop target revenues by rate group, and then by rate classes within each group (Exh. ES-RDC-1, at 27-28, 30). The Company states that this variation of the traditional target class revenue allocation first to rate groupings, and then to rate classes, was utilized in an effort to align rate classes within each group and create a path to equalization of rates (Exh. ES-RDC-1, at 30). The Company developed rate groups by aggregating the revenue requirement for similar rate classes as follows: residential customers, small C&I customers, medium C&I customers, large C&I customers, Company-owned streetlights, and customer-owned streetlights (Exh. ES-RDC-1, at 30).

The Company performed four steps to construct the base distribution revenue requirement for each rate group (Exh. ES-RDC-1, at 27). First, the Company simulated current test-year revenues using rates in effect on January 1, 2022, and test-year billing quantities (Exhs. ES-RDC-1, at 27; ES-RDC-2 (Rev. 3)).[201] Second, the Company performed an ACOSS to determine the revenue requirement by rate class at EROR, as discussed in Section XVII.B.2 (Exhs. ES-RDC-1, at 27, 31; ES-ACOS-2 through ES-ACOS-5 (Rev. 3); ES-RDC-2 through ES-RDC-5 (Rev. 3)). Third, the Company summed the individual class revenue requirements at EROR for each of the proposed residential, small general service, medium general service, large general service, Company-owned streetlights, and customer-owned streetlights groups (Exh. ES-RDC-1, at 31). As part of the third step, the Company also included the proposed transfer of $46,794,254 associated with the SECRF, the RTW factor, and the SMART factor into current base distribution rates[202] for the purpose of applying the 200-percent base distribution rate cap (Exhs. ES-RDC-1, at 24-25; ES-RDC-2, Sch. 4-9 (Rev. 3); ES-REVREQ-2, Sch. 1, at 9 (Rev. 4)). The Company made an offsetting adjustment to reconciling revenues to reflect the change in the reconciling revenues to the total increase in rates when applying the ten-percent total revenue cap (Exhs. ES-RDC-2, Sch. 4-9 (Rev. 3); ES-REVREQ-2, Sch. 1,

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[201] Beginning with its May 13, 2022, updated ACOSS, the Company provided its rate design using 2021 billing determinants to derive its allocated costs.

[202] The Company proposed to transfer $21,700,536 for the SECRF, $23,200,000 for the RTW factor, and $1,893,718 for the SMART factor.

at 9). The adjustment also reflected the increase in basic service charges resulting from the alignment of some customer classes among the small and medium C&I rate groupings (Exh. ES-RDC-1, at 25-26). Further, the Company increased the Residential Assistance Adjustment factor ("RAAF") revenues resulting from the proposed increase in the low-income discount rate (Exhs. ES-RDC-1, at 27; ES-RDC-2, Sch. 4-10 (Rev. 3)).

Fourth, the Company applied rate group impact constraints of a ten-percent cap on the increase to total revenues, net of proposed reconciling mechanism revenue changes, from the change in base distribution revenues, followed by a 200-percent cap on base distribution revenues from the average increase to base distribution revenues, and then a zero-percent rate increase floor to derive target revenues by rate group (Exhs. ES-RDC-1, at 28, 30-34; ES-RDC-2, Sch. 5 (Rev. 3)).

Next, the Company calculated the rate class revenue targets using the following steps. First, the Company calculated an average distribution unit cost for each rate group by dividing its target revenue derived in the previous step by the amount of its test year kWh sales for the residential, small general service, and street lighting groups and by its test year billing demand for the medium general service and the large general service groups (Exhs. ES-RDC-1, at 31-34; ES-RDC-2, Sch. 5-9 (Rev. 3)). Second, for each rate class the applicable group average distribution unit cost was multiplied by the applicable test year billing determinants for that rate class to determine a total distribution revenue target prior to applying the rate class impact constraints (Exhs. ES-RDC-1, at 31-34; ES-RDC-2, Sch. 5-9 (Rev. 3)). Third, the Company applied a ten-percent cap on the increase to total revenues, net of proposed reconciling mechanism revenue changes, from the change in base distribution revenues and allocated any rate class revenue that exceeded the cap to rate classes within the rate group that did not exceed the cap. Similarly, the Company applied a 200 percent cap on base distribution revenues from the average increase to base distribution revenues and allocated any rate class revenue within the rate group that exceeded the cap to rate classes within the rate group that did not exceed the cap. Finally, the Company applied a zero-percent floor in distribution revenue decreases and allocated any excess distribution revenue to rate classes within the rate group that did not reach the floor (Exhs. ES-RDC-1, at 27, 30-31; ES-RDC-2, Sch. 6-9 (Rev. 3)).

With respect to rate class impact constraints and the rate class revenue allocation process, the Company states that in D.P.U. 13-90, the Department elaborated that to conform to Section 94I, the following steps should be taken: (1) calculate total revenues for each rate class using the most recently effective rates; (2) calculate the revenue cap for each rate class at ten percent of the total revenues for each rate class; (3) determine if any rate class will receive a base rate increase greater than this revenue cap when designing rates at EROR; and (4) for those rate classes that have a base distribution rate increase that exceeds the cap, allocate the total amount over the cap to the rate classes that are under the cap based on their current base rate revenue levels (Exh. ES-RDC-1, at 29). The Company also notes that in D.P.U. 15-155 and D.P.U. 15-80/15-81, the Department directed both companies to allocate the revenue requirement that exceeds the ten-percent cap to those rate classes that did not exceed the cap based on their distribution revenue requirements at EROR (Exh. ES-RDC-1, at 29). The Company states that it applied the aforementioned constraints to limit rate group and rate class revenue increases to ten percent of total revenue and 200 percent of the average distribution revenue increase (Exh. ES-RDC-1, at 28).

In D.P.U. 20-120, at 485, the Department directed all distribution companies to include a proposal in future base distribution rate cases to eliminate cross subsidies over time if the increase to any one rate class based on EROR exceeds ten percent (Exh. ES-RDC-1, at 36-37). In its initial filing, the Company proposed that an initial attempt to eliminate class cross-subsidies should be made by restricting allocations of revenues exceeding the ten-percent cap between residential and general service (including streetlights) customer groups (Exh. ES-RDC-1, at 36-37). The Company proposed that any revenue exceeding the ten-percent cap from a residential rate class would not be allocated to any general service rate class and no revenue exceeding the ten-percent cap from a general service rate class would be allocated to a residential rate class (Exh. ES-RDC-1, at 36-37). The Company also proposed that if this restriction could not be met (i.e., all rate classes in either the general service or residential group exceed the ten-percent cap), then the allocation of revenue across residential and general service groups would be allowed (Exh. ES-RDC-1, at 37). While the Company's streetlighting rate group exceeded the ten-percent cap when the ACOSS was initially filed, the Company did not implement the aforementioned reallocation in its initial filing, because the Department's Order in D.P.U. 20-120 was issued on September 30, 2021, and the Company's target revenue allocation process was at a late stage (Exh. ES-RDC-1 at 37). However, the Company took the opportunity to implement the reallocation when it filed its first revised ACOSS on May 13, 2022 (Exh. RDC-2, Sch. 5 (Rev. 1). The Company reallocated the excess revenues to other general service rate groups, but not to the residential rate group (Exh. ES-RDC-2, Sch. 5 (Rev. 3)).

After applying the ten-percent total revenue cap, the Company applied the 200-percent base distribution revenue cap, which was exceeded by Rate S-2, customer-owned streetlights, in the amount of $80,430 (Exh. ES-RDC-2, Sch. 5 (Rev. 3)). After allocating the excess revenues to the remaining non-residential rate groups, the Company implemented a revenue floor for base distribution revenue increases of zero dollars, though no rate group triggered this rate floor and, as such, no reallocation was necessary (Exh. ES-RDC-2, Sch. 5 (Rev. 3)). As explained above, the Company used the final revenue allocations by rate group to determine the target revenue allocation to individual rate classes (Exh. ES-RDC-1, at 31). In applying the rate class impact constraints to rate classes, numerous classes also experienced revenue increases in excess of the ten- and 200-percent caps (Exhs. ES-RDC-5; ES-RDC-2, Schs. 6 through 9 (Rev. 3)).

b. Positions of the Parties

i. Attorney General

The Attorney General argues that the Company, without justification or evidentiary support, applied the revenue allocation constraints in contravention of Department precedent established in D.P.U. 19-120 and that this error impacted the final revenue requirement (Attorney General Brief at 160, citing Exhs. AG-DED-Surrebuttal-1, at 9-10; CLC-JDW-1, at 6; Attorney General Reply Brief at 45-46). In particular, the Attorney General contends that NSTAR Electric's proposed revenue allocation process suffers from two significant errors: (1) the Company applied the Department's constraints (i.e., overall statutory ten-percent total revenue cap, rate increase floor, and relative distribution percent rate increase) in the wrong order; and (2) the Company's proposed allocation results in rate class revenue re-allocations being confined within each proposed rate group (Attorney General Brief at 160-162, citing Exhs. AG-DED-Surrebuttal-1, at 10-11; CLC-JDW-1, at 21).

The Attorney General recommends that the Department require the Company to implement its revenue allocation process consistent with the Department's Order in D.P.U. 19-120 (Attorney General Brief at 161, citing Exh. AG-DED-Surrebuttal-1, at 11). Specifically, the Attorney General argues that the Company should implement its approved revenue allocation with three constraints in the following order: (1) cap the overall total rate increases of no greater than ten percent; (2) apply a rate increase floor of zero percent ensuring that no rate class received a rate decrease in the context of an overall rate increase; and (3) cap the allowed base distribution rate increases equal to a percent multiple of the system average increase (Attorney General Brief at 161, citing D.P.U. 19-120, at 487 (Department Schedule 10); Tr. 8, at 859-862). According to the Attorney General, NSTAR Gas also implemented this order in its final revenue allocation compliance filing approved by the Department (Attorney General Brief at 160-161, citing Tr. 8, at 862).

The Attorney General also disagrees with the Company's proposal to restrict the reallocation of revenues that exceed a constraint to only other rate classes that were part of the same rate group (Attorney General Brief at 160). The Attorney General argues that because the Company performed its class cost of service study on a rate class basis, this restriction is unnecessary and counter-productive to an overall approach of bringing individual rate classes towards their full cost of service and reducing cross-subsidizes (Attorney General Brief at 162, citing Exh. AG-DED-Surrebuttal-1, at 10-11).

Further, the Attorney General argues that the Company's proposed class rate increases are excessive and inconsistent with rate continuity principles (Attorney General Brief at 162). The Attorney General contends that, to provide greater rate continuity, the Department should limit the base distribution rate increase to any single customer class by 1.25 times the overall system average increase, after the application of the statutory ten-percent cap in total overall rates (Attorney General Brief at 163, 165, citing Exh. AG-DED-1, at 11). According to the Attorney General, this limit would reduce the maximum revenue increase in base distribution rates to any single customer class to 15.88 percent, as opposed to the Company's proposed 25.4-percent maximum increase (Attorney General Brief at 163, 165, citing Exhs. AD-DED-1, at 12; AG-DED-3, Schs. 1, 2). Finally, the Attorney General recommends that rate increases that exceed the statutory ten-percent cap in total rates be phased in over the course of the Company's proposed multi-year rate plan (Attorney General Brief at 163-164, 165, citing Exh. AG-DED-1, at 12).

ii. Cape Light Compact

Cape Light Compact asserts that NSTAR Electric made two significant errors in following Department precedent in its revenue allocation (CLC Brief at 9). Specifically, Cape Light Compact argues that the Company performed the revenue increase constraints in the incorrect order and incorrectly applied the revenue floor to base distribution revenues rather than to total revenues (CLC Brief at 9-12, 17-18; CLC Reply Brief at 4). Cape Light Compact further contends that NSTAR Electric's proposed target revenue allocation process results in unjust and unreasonable rate decreases to four general service rate classes (CLC Brief a 14-16).[203] Cape Light Compact asserts that these four rate class decreases create an unfair class subsidy in favor of small and medium general legacy Boston Edison customers over small and medium general customers in other parts of the Company's service area (CLC Brief at 16).

Cape Light Compact argues that NSTAR Electric's proposed target revenue allocation should be rejected, and that the Company should be required to revise its revenue allocation consistent with Department precedent in D.P.U. 19-120 (i.e., proper ordering of the caps and floors and application of the floor based on total revenues) (CLC Brief at 16-18). According to Cape Light Compact, following the method established in D.P.U. 19-120 will result in small rate classes receiving a disproportionate credit or significant violations of the floor in subsequent application of the 200-percent cap because it is applied after the floor (CLC Brief at 16, citing Exh. CLC-JDW-1 at 10-11). Cape Light Compact asserts that this issue can be resolved with two modifications – (1) if more than one iteration of the floor is necessary, the credit from reapplying the floor in subsequent iterations could be allocated to rate classes that

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[203] The four rate classes are: Rate G-1/T-1 (Boston Edison); Rate G-5 (Commonwealth Electric); Rate G-2 (Boston Edison); and Rate WR (Boston Edison) (CLC Brief at 16).

already benefitted from the ten-percent cap, and (2) where the total revenue increase is very nearly zero, rather than applying the floor, each rate in the affected class could receive the same increase in the revenue requirement (CLC Brief at 16, citing Exh. CLC-JDW-Surrebuttal-1 at 13; CLC Reply Brief at 2-3).

iii. TEC and PowerOptions

TEC and PowerOptions argue that the Section 94I cap allocation process serves the dual purpose of limiting rate shock while moving closer to cost-based rates over time (TEC/PowerOptions Reply Brief at 10). Further, they contend that the dual purpose of the ten-percent and 200-percent caps, in that order, was important to ensure that rates are ultimately cost based and provide continuity in the form of measured increases for rates that are not delivering their costs of service at EROR (TEC/PowerOptions Reply Brief at 10). In addition, TEC and PowerOptions claim that the order in which the constraints are applied is important because a rate that is adjusted in excess of its cost of service should not be required to bear additional cross subsidies beyond the addition of revenue required for the revenue floor adjustment (TEC/PowerOptions Reply Brief at 11). TEC and PowerOptions, however, disagree with Cape Light Compact's recommendation to apply a total revenues floor (TEC/PowerOptions Reply Brief at 11).

According to TEC and PowerOptions, the Department should order that the sequence of operations proceed as follows: (1) apply the ten-percent cap; (2) apply base distribution revenue floor to ensure that no rate class experiences a rate decrease; (3) apply the revenue addition from the base distribution revenue floor as a credit to excess revenues allocated as part of the ten-percent cap; and (4) apply the 200-percent cap excluding rate classes subject to a revenue floor adjustment from bearing additional allocation of revenue from other classes in excess of the 200-percent cap (TEC/PowerOptions Reply Brief at 12).

iv. Company

The Company summarizes its distribution rate allocation process (Company Brief at 392-399). In response to the intervenor positions, NSTAR Electric asserts that, overall, the Company's process in developing its proposed rate design and subsequent revenue allocation through analyzing and applying the Department's long-standing rate design goals is consistent with Department precedent, despite not implementing the same process applied in D.P.U. 19-120 (Company Brief at 420-421, citing Exhs. ES-RDC-1, at 6; ES-RDC-Rebuttal-1, at 7-8). According to the Company, there is no Department requirement regarding the proposed sequencing of the overall statutory ten-percent cap, rate increase floor, or relative distribution-percent rate increase (Company Brief at 421). Rather, the Company contends that the Department is not precluded from considering appropriate alternative allocation methods than the method used D.P.U. 19-120 (Company Brief at 421, citing D.P.U. 19-120, at 421). The Company asserts that its revenue allocation process, although not consistent with D.P.U. 19-120, nevertheless is consistent with the Department's rate design objectives and balances various ratemaking objectives, such as efficiency and rate stability (Company Brief at 421, citing Exhs. ES-RDC-1, at 40; ES-RDC-Rebuttal-1, at 5, 7-8).

Further, NSTAR Electric argues that Cape Light Compact's recommendation to apply a total revenues floor is also inappropriate, as it would leave the Company with no control over the level of distribution pricing because the final distribution rates become a by-product of the total revenue floor (Company Brief at 421, citing Exh. ES-RDC-Rebuttal-1, at 7). The Company maintains that a floor on total revenue forces further reallocation of distribution revenue targets and prevents rates from ever reflecting the cost of service (Company Brief at 421, citing Exhs. ES-RDC-Rebuttal-1, at 7; DPU 36-6).

NSTAR Electric also rejects the Attorney General's argument that the Company's proposed allocation process results in rate class revenue reallocations being confined within each proposed rate group (Company Brief at 421). In addition, the Company disputes Cape Light Compact's assertion that the allocation process results in unjust and unreasonable rate decreases for four general service rate classes (Company Brief at 421). The Company argues that its proposed rate class groupings were established based on continuity and simplicity and are necessary to make progress in aligning the pricing among legacy rate classes (Company Brief at 421, citing Exhs. ES-RDC-1, at 21; DPU 11-6).

c. Analysis and Findings

As a first step in its revenue allocation process the Company appropriately began its allocation with revenues at EROR per the ACOSS (Exh. ES-RDC-1, at 28). The Company then grouped customer classes into six groups based on the proposed characteristics for each class and group: residential rate classes, small C&I rate classes, medium C&I rate classes, large C&I rate classes, Company-owned streetlights, and customer-owned streetlights

(Exh. ES-RDC-1, at 16). The Company grouped its rate classes in an effort to align the availably characteristics of similar rate classes, as a step toward rate consolidation in the future (Exh. ES-RDC-1, at 22). After determining the appropriate target revenue, by applying the rate constraints to the revenue requirement at EROR for each rate group, the Company applied the resulting target revenues' unit costs to each rate class within each group, and then within each rate group applied again the rate class revenue constraints to derive each rate class's final base distribution revenue requirement (Exh. ES-RDC-1, at 30-31). The Department finds that the foregoing steps reflect reasonable efforts to align the availability characteristics of similar rate classes.

In applying its group and rate class revenue constraints, the Company took into consideration its proposed transfer to base distribution rates of revenues currently recovered through the SECRF, SMART factor, and the RTW factor, along with the change to the RAAF associated with increasing the low-income discount rate (Exhs. ES-RDC-1, at 24-25, 27; ES-RDC-2, Sch. 4-10 (Rev. 3); ES-REVREQ-2, Sch. 1, at 9 (Rev. 4)). In Section XIV.A.4 above, the Department disallowed the transfer of SMART Program investments to base distribution rates, and in Section XI.C.4.b above, the Department disallowed the transfer of the RTW Program costs to base distribution rates. Moreover, in Section XVII.C.3 below, the Department approved an increase to the low-income discount from 36 percent to 42 percent. Also, in Section XV.C.2 above, the Department directed the Company to remove meter-related capital from base distribution rates and, instead, recover these costs through the AMI reconciling factor. Accordingly, in its compliance filing, the

Company shall adjust the base distribution revenues to comply with these directives, for the purpose of applying the 200-percent base distribution rate cap (Exhs. ES-RDC-2, Sch. 4-9 (Rev. 3); ES-REVREQ-2, Sch. 1, at 9 (Rev. 4)). In addition, to comply with these directives, the Company shall make offsetting adjustments to reconciling rate revenues for the purpose of applying the ten-percent total revenue cap.

Next, the Company applied a series of revenue constraints. The Company proposes a distribution rate allocation process that does not follow the order set forth in D.P.U. 19-120, at 487 (see Exhs. ES-RDC-1, at 28, 30-34; ES-RDC-2, Sch. 5 (Rev. 3)). In D.P.U. 19-120, the Department applied revenue constraints in the following order: ten-percent cap on the total revenue increase, followed by the zero percent floor on distribution revenue, followed by a 200 percent cap on overall distribution revenue increase. D.P.U. 19-120, at 487. However, we note that in D.P.U. 20-120, the Department applied revenue constraints in the following order: ten-percent cap on the total revenue increase, followed by a 200-percent cap on overall distribution revenues, and no revenue floor. D.P.U. 20-120, at 538-540. In the instant case, NSTAR Electric applied the ten-percent cap on total revenue increase, followed by a 200-percent cap on the overall distribution revenue increase, followed by the zero-percent floor on distribution revenue to ensure that a rate class does not receive a distribution rate decrease (Exhs. ES-RDC-1, at 28, 30-34; ES-RDC-2, Sch. 5 (Rev. 3)).

To reach fair decisions that encourage efficient utility and consumer actions, the Department's rate structure goals must balance the often-divergent interests of various customer classes and must prevent any class from subsidizing another class unless a clear record exists to support such subsidies, or unless such subsidies are required by statute. D.P.U. 19-120, at 431. To achieve such balance, flexibility in the revenue allocation method may be warranted, so long as the results do not violate our rate structure goals or result in unjust or unreasonable rates. Without such flexibility, the Department cannot develop rates that adequately allow for the consideration of efficiency, simplicity, continuity, fairness, and stability. As such, we decline to adopt the intervenors' recommendations to strictly follow the revenue constraints set forth in D.P.U. 19-120. In addition, we find that implementing a floor on distribution revenue increases at zero percent mitigates intervenor concerns regarding the subsidization of legacy Boston Edison small and medium general service customers by small and medium general service customers in other legacy service areas.

As noted, the Company began its allocation process by applying the ten-percent total revenue cap as mandated by Section 94I first to each customer rate group[204] to determine the unit cost and later to each proposed rate class within each customer rate group (Exh. RDC-2, at Sch. 5 (Rev. 3)). In D.P.U. 20-120, at 485, the Department directed all gas and electric companies to include a proposal in their future base distribution rate cases to eliminate cross subsidies over time if the increase to any one rate class based on EROR exceeds ten percent. The Company suggested that one option would be to restrict revenues that exceeded the ten-percent cap between residential and general service customer groups, inclusive of streetlights (Exh. ES-RDC-1, at 36-37). Beginning with its first revised ACOSS and

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[204] Residential, small C&I, medium C&I, large C&I, customer-owned streetlights, and Company-owned streetlights.

continuing through later iterations, the Company implemented this proposal to reallocate the overage from its streetlighting rate group; the overage was assigned to other general service rate groups, but not to the residential rate group (Exh. ES-RDC-2, Sch. 5 (Rev. 3)). Notwithstanding our decision below, to address our goals of continuity and fairness and to maintain the flexibility required to properly balance our rate structure goals, no rate group should be exempt from being allocated any revenues in excess of the ten-percent cap. The Department is not convinced that restricting revenues that exceed the ten-percent cap between residential and general service customer groups will assist in eliminating cross subsidies over time. Moreover, the Company did not submit a specific proposal regarding the D.P.U. 20-120 directive when applying the ten-percent cap to each rate class within each group. Nevertheless, in this instance, we accept the Company's implementation of the Section 94I ten-percent cap at the rate class level within each group because it will help with the future alignment of the Company's C&I rate classes. Therefore, in its compliance filing, the Company shall include all rate groups in the reallocation of revenues in excess of the rate group revenue constraint caps, and we accept the Company's application of the ten-percent cap to individual rate classes within each rate group. We reiterate that all gas and electric companies shall include a proposal in their future base distribution rate cases to eliminate cross subsidies over time if the increase to any one rate class based on EROR exceeds ten percent. D.P.U. 20-120, at 485.

The Company next proposes for each rate class a distribution revenue increase cap of 200 percent (or a multiplier of 2.0) of the system overall increase (Exh. ES-RDC-1, at 28).

The Attorney General argues that a multiplier of 1.25 is more appropriate (Attorney General Brief at 163, 165, citing Exh. AG-DED-1, at 11). As noted above, the Department balances numerous principles when determining the appropriate multiplier to apply to the average increase in base distribution rates. The Department finds that use of a 2.00 multiplier adequately balances the principle of fairness with resulting customer bill impacts. D.P.U. 18-150, at 583; D.P.U. 17-05-B at 325.

Next, the Company applied a zero-percent revenue floor to its proposed base distribution rates after applying the ten-percent and 200-percent rate caps (Exh. ES-RDC-2, Sch. 5 through Sch. 9 (Rev. 3)). Cape Light Compact argues that the floor should be applied to total revenues, not just base distribution revenues (CLC Brief at 17-18; CLC Reply Brief at 4-5). The Department finds it reasonable to accept the Company's zero-percent distribution revenue floor, as it will limit the increases to other rate classes and will meet the Department's goal of fairness (Exh. DPU 36-6). Further, we find that setting the revenue floor using base distribution revenues provides a more equitable result, as reconciling revenues, which vary from year to year, are excluded. Further, using base distribution revenues avoids further reallocation of distribution revenue targets and ensures that the revenue floor more accurately reflects the cost of service (Exh. ES-RDC-Rebuttal-1, at 7). For these reasons, the Department directs the Company in its compliance filing to apply a zero-percent floor on base distribution revenues as the last revenue constraint in its allocation process.

Based on our findings above, we conclude that the Company's revenue allocation process is reasonable and appropriate and will result in just and reasonable rates. Accordingly, we approve this aspect of the Company's rate design.

5. Transmission Rate Allocation and Design

a. Introduction

The Company states that transmission rates are currently allocated to rate classes based on the twelve-month coincident peak ("12 CP") method, meaning that the Company's total retail transmission revenue requirement is allocated to rate classes based on each class's contribution to the annual coincident peak experienced on the transmission system for a particular year (Exh. ES-RDC-1, at 22). The allocated revenue requirement is then translated into a rate using the approved rate design for the class (Exh. ES-RDC-1, at 22). As such, each rate class has its own unique transmission rate (Exh. ES-RDC-1, at 22). Individualized rates and unique rate designs present a challenge to any effort to consolidate rates, but the Company proposes to alter the transmission allocation method as part of its overall rate alignment efforts (Exh. ES-RDC-1, at 22-23).

As with distribution rates, the Company proposes to categorize rate classes into the five distinct rate groups discussed above, with the customer-owned streetlighting and the Company-owned streetlighting combined into one rate group and to allocate the transmission revenue requirement to each of the rate groups using the 12 CP method (Exh. ES-RDC-1, at 23). However, because the difference between an individualized rate class allocation and the applicable rate group allocation is too large for certain classes, the Company does not propose a single allocation by rate group to apply to all rate classes within a group (Exh. ES-RDC-1, at 23). With respect to WMA Rate T-5, the 12 CP method is applied to individual customer billing for transmission rates (Exh. ES-RDC-6, Sch. 2, at 188). In this method of billing, customers are first charged based on monthly non-coincident peak demand but are subsequently rebilled based on their coincident-peak demand (Exh. UMass 1-7; Tr. 8, at 827). For other large general service rate classes, the Company bills customers on their monthly non-peak demand (Exh. UMass 1-7).

The following table includes an illustrative depiction of the Company's proposed transmission revenue allocation:

Rate Group	**Proposed Rate Class**	**Allocation of Transmission Revenue Requirement**
Residential	R-1/R-2, R-3/R-4	44.14%
Small General Service	G-1 (ALL), T-1 (Boston Edison), G-5 (Cambridge Electric Light), G-6 (Commonwealth Electric), 24 (WMA) G-7 (Commonwealth Electric) 23 (WMA)	19.30% 0.22% 0.0002%
Medium General Service	G-2 (ALL), T-4 (WMA)	19.22%
Large General Service	G-3 (ALL), T-5 (WMA) WR (Boston Edison)	16.59% 0.26%
Streetlights	S-1/S-2	0.28%

Exh. ES-RDC-2, Sch. 3, at 3 (Rev. 3).

NSTAR Electric also proposes a change in transmission rate design for certain rate classes in the small general service group to better align with the proposed distribution rate designs and the Company's movement toward more energy-focused rate design for this group of customers (Exh. ES-RDC-1, at 23). The Company states that, while transmission rate design changes are only proposed for the small general service group, all rate classes will experience rate changes because the proposed allocation is revenue neutral in total (Exh. ES-RDC-1, at 24). The Company provides the following table to summarize the proposed transmission rate design changes:

Legacy Rate Class	**Proposed Transmission Rate Design Change**
G 1NDMD (Boston Edison), T-1 (Boston Edison), G-0 (Cambridge Electric Light), G-6 (Cambridge Electric Light), G-1 (Commonwealth Electric), G-5 (Commonwealth Electric), G-6 (Commonwealth Electric), 23 (WMA), 24 (WMA)	None
G-1DMD (Boston Edison)	Convert from two-part demand/energy rate to energy only rate
G-2 (Boston Edison) (< =100 kW customers only), T-2 (Boston Edison) (< =100 kW customers only), G-1 (Cambridge Electric Light), G-4 (Cambridge Electric Light), G-7 (Commonwealth Electric) G-0 (WMA) (< =100 kW customers only), T-0 (WMA) (< =100 kW customers only), G-2 (WMA) (< =100 kW customers only), T-4 (WMA) (< =100 kW customers only)	Convert from demand-only rate to energy-only rate
G-5 (Cambridge Electric Light)	Convert from inclining block energy rate to flat energy-only rate
G-4 (Commonwealth Electric)	Convert from two-part demand/energy rate to energy-only rate

Exh. ES-RDC-1, at 24.

b. Positions of the Parties

i. TEC and PowerOptions

TEC and PowerOptions request two revisions to the Company's transmission rate design and offerings (TEC/PowerOptions Brief at 5-10). First, TEC and PowerOptions request that the Company expand coincident peak transmission billing from customers taking service under WMA Rate T-5 to all large customers in the Company's EMA service territory (TEC/PowerOptions Brief at 5). TEC and PowerOptions argue that the Department should expand the availability of coincident peak transmission billing on an opt-in basis to large customers who have flexible loads and/or DG that can reduce demands during transmission system peak hours (TEC/PowerOptions Brief at 8).

TEC and PowerOptions assert that the Department has previously found that coincident peak billing for transmission eliminates inequities by charging customers based on their individual consumption at the time of system peak (TEC/PowerOptions Brief at 5, citing D.P.U. 10-70-B at 5). Further, TEC and PowerOptions contend that the Department has previously found that coincident peak billing is consistent with cost causation principles and can produce benefits by reducing congestion during system peak hours, leading to flatter load profiles and system utilization and reducing long-term transmission costs (TEC/PowerOptions Brief at 5, citing D.P.U. 10-70-B at 5; Western Massachusetts Electric Company, D.P.U. 12-97, at 13-14 (2013)). Furthermore, TEC and PowerOptions argue that customers taking service under Rate T-5 in the WMA service area have had coincident peak transmission billing for approximately eight years and appear to be responding to price signals and reducing load during monthly peak hours (TEC/PowerOptions Brief at 5, citing Exh. TEC/PO-JDB-1; Tr. 8, at 928).

TEC and PowerOptions assert that should the Department agree with expanding 12 CP billing to more large customers, that customers wishing to opt in to such a billing option should be required to post deposits and pay for incremental administrative costs associated with bill generation (TEC/PowerOptions Brief at 8, citing RR-DPU-35). TEC and PowerOptions also recommend that expansion of coincident peak billing in the Company's EMA service area should be limited to an initial pilot of approximately 35 customers in the G-3 customer group, with a waiting list if necessary (TEC/PowerOptions Brief at 8, citing RR-DPU-36). To address automating the Company's systems to accommodate 12 CP transmission billing in the future, TEC and PowerOptions assert that the Department should ensure that AMI and CIS systems have the ability to automate such billing structures to reduce the administrative effort associated with implementing this rate design at this time (TEC/PowerOptions Brief at 8-9).

Additionally, TEC and PowerOptions recommend changes to the Company's proposed consolidated Rate G-1, which has both non-demand and demand-based rate options (TEC/PowerOptions Brief at 9). TEC and PowerOptions argue that the Company's proposed G-1 demand customers' transmission rate is a volumetric charge, which would result in an inequity to high load factor customers with their paying much more for transmission service than they would under a demand charge (TEC/PowerOptions Brief at 9; TEC/PowerOptions Reply Brief at 3). Thus, TEC and PowerOptions assert that the Department should direct the

Company to implement a demand-based transmission rate for Rate G-1 demand customers (TEC/PowerOptions Brief at 9).

ii. UMass

UMass asserts that new laws require the Department to prioritize GHG emission reductions and to consider the impacts of rate design decisions on the deployment of DER that support the Commonwealth's climate and clean energy policies (UMass Brief at 20-21, citing 2022 Clean Energy Act, §§ 56 & 57; 2021 Climate Act, § 15; G.L. c.164, §§ 141, 142; UMass Reply Brief at 3-5). Thus, UMass argues that it is critical for the Department to prioritize efficient rate structures that support the Commonwealth's clean energy and climate policies (UMass Brief at 20-25). In this regard, UMass contends that the time is right to expand access to the T-5 rate structure (UMass Brief at 20; UMass Reply Brief at 5-6).

UMass asserts that transmission charges are particularly amenable to efficient rate design because they are assigned to the Company based on a known tariff formula (UMass Brief at 12). Further, UMass contends that the T-5 rate has been in effect for years in the WMA service area and has proven that it affects customers' decision-making on grid usage and that provides significant customer benefits (UMass Brief at 12-13). In addition, UMass argues that the T-5 rate should send efficient price signals that encourage customer action, such as deploying energy storage and on-site generation, which would support Massachusetts energy and climate policies (UMass Brief at 13-15). UMass also claims that a T-5 rate structure for transmission charges is superior to the other structures proposed by the Company vis-à-vis the Department's rate structure goals of simplicity, continuity, fairness, and earnings stability (UMass Brief at 13, 25-27). In particular, UMass asserts that amending transmission rates for large general service customers will affect only the Company's largest customers, who are well equipped to respond to the resulting price signals and capable of doing so (UMass Brief at 13).

UMass asserts that the Department should require that NSTAR Electric expand its T-5 rate design to all large general service customers in the EMA and WMA service areas starting in January 2024 (UMass Brief at 13, 27-29). Further, UMass asserts that the Department should require NSTAR Electric to assess monthly transmission charges to all its large general service customers based on their average 60-minute grid demand during the hour in which the Company's applicable Regional Network Service load peaks for that month, as the Company currently does for T-5 customers (UMass Brief at 13, citing Exh. UMASS-EP/RS-1, at 28).

iii. Company

The Company argues that 12 CP transmission billing should not be expanded to all large general service customers. First, the Company contends that it needs to collect the costs associated with the system that has been constructed to serve large general service customers, and if these large general service customers reduce demand during the system peak for the month, transmission costs for that month will be reduced only to the extent that such activity was not forecasted by the Company (Company Brief at 431-432, citing Exh. ES-RDC-Rebuttal-1, at 10).

Second, the Company claims that 12 CP transmission billing is inefficient in that it produces a price signal that cannot be acted upon since the coincident peak is not known until the billing month has concluded (Company Brief at 432, citing Exhs. ES-RDC-Rebuttal-1, at 11; DPU 58-4; UMASS-ES 1-7). The Company asserts that some customers with DG may be able to reduce load around a board time space to cover the anticipated coincident peak, but less sophisticated customers and those without DG may not be able to pinpoint accurately the moment at which they should curtail use in order to lower their overall cost (Company Brief at 432). Thus, the Company argues that 12 CP transmission billing provides an accurate basis for consumer decisions (Company Brief at 433-434).

c. Analysis and Findings

The Department has previously stated that pricing transmission service based on a customer's use at the time of system peak rather than based on the customer's peak, which may not coincide with the system peak, provides a more equitable assignment of cost responsibility. D.P.U. 17-05-B at 212; D.P.U. 10-70-B at 6. The 12 CP billing for Rate T-5 is one method of efficiently assigning accurate costs to those customers who utilize the transmission system during peak periods. While customer behavior benefits from 12 CP may not result in lower system costs immediately, lower system peak usage will eventually be reflected in transmission system peak forecasts, lowering costs for all customers.

In the Company's last base distribution rate case, the Department directed the Company to evaluate the further expansion of coincident peak transmission billing to NSTAR Electric customers; however, the Company did not undertake any such evaluation that could assist the Department in weighing the merits of the proposed use of 12 CP transmission billing for all large customers (Tr. 8, at 922-924). D.P.U. 17-05-B at 213. As the Company has made and continues to make efforts toward rate alignment, and as 12 CP billing supports numerous rate-making goals such as simplicity and efficiency, the Department finds that it is reasonable and appropriate for the Company to expand optional 12 CP transmission billing to all large general service customers.

The Department recognizes that, in the immediate future, there may be administrative challenges associated with the Company's ability to implement 12 CP transmission billing using its current billing system (Exhs. ES-RDC-Rebuttal-1, at 14; UMass 1-9; UMass 1-11; Tr. 8, at 833-835). Further, the Department acknowledges that not all customers have the appropriate information to evaluate and decide whether 12 CP transmission billing is a beneficial option. Based on these considerations, we find that it is prudent for the Company to implement 12 CP billing for transmission service on an opt-in basis for large general service customers, effective January 1, 2023. Further, the Company estimates an average cost of $500 to produce a single Rate T-5 bill each month under its current billing system (Exh. DPU 58-6; Tr. 8, at 946; RR-DPU-35). We find it reasonable for the Company to assess a $500 bill preparation fee for customers who choose to opt in to 12 CP transmission service; the $500 fee will not apply to a customer that does not elect this service. The overall $500 fee shall remain in place until the Company has transitioned to its new billing system at the end of 2024 (Exh. UMass 1-11).[205]

Finally, with respect Rate G-1 demand customers, we find that it is appropriate for the Company to bill those customers a demand charge for transmission service rather than a volumetric charge. The existence of both a demand and non-demand charge inherently recognizes that different customers utilize the electric system differently. For customers where a demand charge for distribution service is preferable, and more accurately reflects the costs to serve such customers, it follows that transmission charges should be demand based as well. As such, the Department directs the Company to develop demand-based transmission charges for the Rate G-1 demand classes effective January 1, 2023.

6. Reconciling Rate Allocation Factors

a. Introduction

The Company proposes to condense the number of distribution revenue allocators ("DRA") and labor allocators, by calculating rate group values rather than rate class values (Exhs. ES-RDC-1, at 25; ES-RDC-2, Sch. 4, at 1 (Rev. 3)). The proposed rate groups are the same as those proposed for base distribution rate allocation except for small general service and streetlights forming a single group (Exh. ES-RDC-1, at 25). The DRA is a

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[205] During evidentiary hearings, the Company noted that it as prepares to issue a request for proposals ("RFP") relative to its new billing system, it would be a "good opportunity" to evaluate the propriety of including automated 12 CP transmission service billing into system (Tr. 8, at 836). As such, we expect the Company to include this function as part of the RFP.

function of the proposed distribution revenue targets, and the labor allocator is developed in the ACOSS (Exh. ES-RDC-1, at 25).

The Company proposes to use these updated allocators to derive rate group target revenues for reconciling rates, by aggregating total revenue required for each reconciling rate and then assigning the appropriate allocator to each group to derive the total revenue target for each reconciling rate (Exhs. ES-RDC-1, at 25; ES-RDC-2, Sch. 5, at 1 (Rev. 3)). Next, the Company divides each group's target revenue by each group's test year kWh sales to derive a unit rate for each group for each reconciling factor (Exh. ES-RDC-2, Sch. 5, at 1 (Rev. 3)).

The proposed values are:

Rate Group	**Distribution Revenue Allocator**	**Labor Allocator**
Residential Service	52.254%	54.323%
Small General Service/Streetlights	20.282%	20.748%
Medium General Service	16.658%	14.836%
Large General Service	10.806%	10.092%

Exh. ES-RDC-2, Sch. 4, at 1 (Rev. 3). No other party addressed this issue on brief.

b. Analysis and Findings

The Company's proposed use of the rate group approach to calculate the DRA and labor allocator calculations is consistent with the Company's proposed alignment efforts in distribution and transmission rates. We find that the shift to rate group allocators for reconciling rates and the use of single values for all rate classes within a group for reconciling rates, are consistent with the rate design goals of efficiency, simplicity, and fairness. Accordingly, the Department approves the move to rate group allocators and the use of those allocation factors to calculate the applicable reconciling rates. The Company in its compliance filing shall revise its tariff accordingly to implement the approved changes to the DRA and labor allocators.

C. Energy Efficiency Surcharge and Low-Income Discount

1. Introduction

On December 10, 2020, the Department opened an investigation to revise its Energy Efficiency Guidelines ("EE Guidelines") to incorporate changes in laws and Department policies and experience gained concerning energy efficiency. Updating Energy Efficiency Guidelines, Order Opening Investigation, D.P.U 20-150 (December 10, 2020).[206] In that Order, the Department presented proposed revisions to the EE Guidelines ("Revised EE Guidelines"),[207] with seven categories of revisions. D.P.U. 20-150, at 2-3. In particular, the Department proposed to update EE Guidelines, § 3.2.1.6 with a revised annual electric energy efficiency surcharge ("EES") calculation to better align the electric and gas EES calculations and to account for Department directives in Cost Based Rate Design,

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[206] The Department first established its EE Guidelines in 2000. Methods and Practices to Evaluate and Approve Energy Efficiency Programs, D.T.E. 98-100 (2000). In 2013, the Department adopted updated EE Guidelines. Updating Energy Efficiency Guidelines, D.P.U. 11-120-A (2013).

[207] The proposed Revised EE Guidelines were set forth in Appendix A to D.P.U. 20-150.

D.P.U. 12-126A through 12-126I at 23 (2013). D.P.U. 20-150, at 3, 13-14; Appendix A at 5-7.

The revised EES calculation would allocate low-income energy efficiency program costs between a single residential and low-income sector and the C&I sector using a DRA and collecting the resulting allocation from each rate class in the sector using a volumetric charge. D.P.U. 20-150, at 14, citing D.P.U. 12-126A through 12-126I at 23. This change would result in two surcharges, one for the residential sector, including low-income, and one for the C&I sector, which is the same structure as the gas EES. D.P.U. 20-150, at 14. Low-income customers would continue to receive a discount on their total electric bill. D.P.U. 20-150, at 14.

In its final Order adopting the Revised EE Guidelines, the Department agreed with comments from the Low-Income Network and other stakeholders that it would be better to implement the revised EES calculation as part of a proceeding where a full analysis of the bill impacts could be performed. D.P.U. 20-150-A at 34. The Department found that, given the interaction between the current electric EES structure and the low-income discount, it was appropriate to conduct this analysis as part of a base distribution rate case proceeding. D.P.U. 20-150-A at 34-35. The Department directed each electric distribution company to submit a revised EES tariff, consistent with the Revised EE Guidelines, as part of its next base distribution rate case proceeding. D.P.U. 20-150-A at 35-36.[208]

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[208] Throughout D.P.U. 20-150-A, the Department referred to the proposed revised EE Guidelines as the Straw Proposal.

In its initial filing, the Company submitted its Energy Efficiency Charges tariff, proposed M.D.P.U. No. 50D, which was not updated pursuant to the directives in D.P.U. 20-150-A (Exh. ES-RDC-6, Sch. 1, at 250-253). Subsequently, the Company submitted a revised tariff (proposed M.D.P.U. No. 50E) to address the Department's findings and directives in D.P.U. 20-150-A (Exh. DPU 1-2, Att.). During the proceedings, the Company also agreed to increase the low-income discount from 36 percent to 42 percent in order to mitigate the bill impact associated with the RPS solar carve out, the net metering recovery surcharge, and the transition to the revised EES (Exhs. DPU 39-1, Att. B (Supp. 1); LI-ES 1-4 & Att.; LI-ES 1-5; CLC-ES 7-2).

2. Positions of the Parties

a. Attorney General

The Attorney General argues that implementing the revised EES calculation at this time will result in significant bill impacts for ratepayers (Attorney General Brief at 17, citing Exh. DPU 39-1, Att. (c) (Supp. 2)). As such, the Attorney General asserts that the Department should delay the implementation of the revised EES calculation until the 2025-2027 three-year energy efficiency cycle to alleviate cost pressure on ratepayers (Attorney General Brief at 178-179). She also notes that delaying the implementation of the revised calculation would obviate the need to increase the low-income discount to 42 percent (Attorney General Brief at 179).

The Attorney General also submits that by delaying the implementation of the revised EES calculation for several years, it is likely that National Grid (electric) and Unitil (electric) would have filed base distribution rate cases that would allow for the required EES-related tariff changes and implementation of the associated changes for those companies (Attorney General Brief at 179). The Attorney General also contends that this delay would allow for additional time to develop policies for the best long-term approach to low-income assistance in light of current economic uncertainties in the greater context of the Commonwealth's priorities for equity and affordability as the state transitions to a clean energy future (Attorney General Brief at 179).

b. DOER

DOER argues that implementation of the revised EES calculation will compound the effect of the Company's proposed increase in base distribution rates and cost increases external to the rate-making process (DOER Reply Brief at 6-7). DOER agrees with the Attorney General that implementation should be delayed until the 2025-2027 three-year energy efficiency cycle to allow for consistency in implementation for all EDCs (DOER Reply Brief at 7).

c. Low-Income Network

The Low-Income Network argues that the Department should not implement a new EES calculation at any time, and instead should retain the old calculation (Low-Income Network Brief at 1). The Low-Income Network points to significant bill increases for low-income customers if the new calculation is implemented (Low-Income Network Brief at 2-3, citing Exh. DPU 39-1, Att. (c) (Supp. 2)). The Low-Income Network contends that these bill impacts, combined with the "worldwide energy crisis", would adversely impact low-income customers (Low-Income Network Brief at 23). Thus, the Low-Income Network asserts that the Department should "withdraw" any proposed increase to the EES (Low-Income Network Brief at 2).

d. Cape Light Compact

Cape Light Compact also argues that implementation of the Company's revised EES calculation will have significant bill impacts on ratepayers (CLC Brief at 37, citing Exh. DPU 39-1 (Supp. 2)). Further, Cape Light Compact contends that the Company's low-income ratepayers should not be subject to higher rates any sooner than low-income customers of National Grid (electric) and Unitil (electric) (CLC Brief at 37). As such, Cape Light Compact asserts that the Department should delay the implementation of the revised EES calculation until it can be done consistently across all EDCs (CLC Brief at 3, 37). In this regard, Cape Light Compact agrees with the Attorney General's timeline for implementation (CLC Reply Brief 15-16). Further, Cape Light Compact asserts that the Department should consider the impact on moderate income ratepayers in any investigation into a long-term approach to low-income assistance (CLC Reply Brief at 16).

3. Analysis and Findings

As an initial matter, the Department has reviewed the Company's proposed Energy Efficiency Charges tariff (proposed M.D.P.U. No. 50E) filed in response to information request DPU 1-2. The Department finds that that proposed tariff complies with the directives of D.P.U. 20-150-A at 34-36. In particular, the revised EES calculation therein allocates low-income energy efficiency program costs between a single residential and low-income combined sector and the C&I sector using a DRA and collects the resulting allocation from each rate class in the sector using a volumetric charge (Exh. DPU 1-2, Att. at 1-3). D.P.U. 20-150-A at 34; D.P.U. 20-150, at 14, citing D.P.U. 12-126A through 12-126I at 23. We affirm that this EES calculation is reasonable. The Department conditionally approves the Company's proposed Energy Efficiency Charges tariff subject to the Company's providing a clean tariff as part of its compliance filing in this case.

Regarding the implementation of the revised EES calculation, the Department directs the Company to calculate a new EES, consistent with the formula presented in proposed M.D.P.U. No. 50E, for effect on July 1, 2023, as part of its next Energy Efficiency Reconciliation Factor ("EERF") filing.[209] The Department Order adopting the Revised EE Guidelines contemplated that each company would provide a revised EES calculation in its next base distribution rate case. D.P.U. 20-150-A at 34-35. Thus, we are not persuaded that the Department should wait until National Grid (electric) and Unitil (electric) have submitted their respective revised EES calculations to begin NSTAR Electric's implementation of the revised calculation. Nor will we revisit our decision to allow for the revised EES calculation, as suggested by the Low-Income Network. The Department, however, continues to share the Low-Income Network's concerns regarding the overall affordability of energy bills, as discussed below. Further, we find that the continuing discussion and development of policies to address low-income assistance are not dependent

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[209] The Cape Light Compact should also recalculate its EERFs based on the revised EES for July 1, 2023.

upon the Company's delaying the implementation of the revised EES calculation. The Department and relevant stakeholders will continue to examine these issues as appropriate in future dockets.

In light of the potential bill impacts resulting from changing the EES calculation and the adjustment to the low-income discount that reflects costs associated with the RPS solar carve out and the net metering recovery surcharge for low-income customers consistent with G.L. c. 164, § 141,[210] the Company agreed to increase the low-income discount from 36 percent to 42 percent (Exhs. DPU 39-1 & Atts. (Supp. 2); LI-ES 1-4 & Att.; LI-ES 1-5; CLC-ES 7-2). The Department finds that this increase in the discount rate is reasonable and approves the proposal. As low-income customers will continue to receive a discount on their total electric bill following implementation of the revised EES calculation, the increase in the discount to 42 percent will help to mitigate the actual impacts from the revised EES calculation, once implemented in the next EERF filing. Further, the Department notes that the implementation of the 42-percent low-income discount rate effective January 1, 2023, will help mitigate winter energy prices for low-income customers, prior to the implementation of

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[210] Section 141 provides that in all decisions or actions regarding rate designs, the Department shall consider the impacts of such actions, including the impact of new financial incentives on the successful development of energy efficiency and on-site generation. Where the scale of on-site generation would have an impact on affordability for low-income customers, a fully compensating adjustment shall be made to the low-income rate discount. The Department notes that Section 141 was amended after evidentiary hearings in this proceeding and, therefore, the Department will not consider the revised language in this proceeding. 2022 Clean Energy Act, § 56. Nevertheless, the amended Section 141 would not have changed the Department's analysis.

the revised EES. Thus, the Department is satisfied that the revised EES calculation should be implemented consistent with the directive above.

The Department recognizes that the revised low-income discount rate constitutes a significant bill discount for low-income customers, and we are mindful of the impacts that increasing the discount rate may have for other customers. Costs associated with providing a low-income discount are recovered from all distribution customers. Accordingly, the Department balances the impact of increasing the discount rate against the impact on other customers, particularly moderate-income residential and small C&I customers. While the Department finds that the revision to the EES, which will result in a EERF reduction for non-low-income residential customers, and the adjustment to the low-income discount are reasonable at this time, the Department notes that adjustments to the low-income discount and framework may be required in the future to provide equity for all customers. The low-income discount rate was historically fixed at 25 percent. Pursuant to G.L. c. 164, § 141, the low-income discount rate has increased in recent years to provide a full offset of DG resources that have, to date, not been as widely adopted by low-income customers.[211] As the low-income discount rate increases, the delta between moderate-income

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[211] Recent changes in law and incentive programs, such as SMART and energy efficiency programs, seek to change the landscape of low-income solar adoption. See, e.g., 2021 Climate Act, §§ 54, 94; 2022 Clean Energy Act, §§ 24, 87A (each section establishing new solar incentive requirements or programs for low-income customers). As low-income participation increases, the Department may revisit the appropriate level of costs that should be offset by a low-income discount pursuant to G.L. c. 164, § 141.

and low-income customer energy costs has become significant. For future base distribution rate cases, EDCs should explore stratifying low-income discount rates in a manner that provides an equitable discount for customers, provides assistance for the most vulnerable customers, and mitigates the potential rate shock for customers that transition from low to moderate income.

The Department recognizes that energy bills have strained many family budgets, and we have learned from the COVID-19 pandemic and our experience with arrearage management that there is a need for a deeper understanding of the impact energy costs are having on households. Further, with the upcoming electric supply issues, ensuring a more in-depth understanding of energy burdens has become essential. To begin collecting more detailed and utility-specific information on energy burden, the Department directs NSTAR Electric to make detailed utility burden index analysis on electricity residential bills in their Annual Returns to the Department, beginning with the 2022 Annual Return submitted in Spring 2023.

With this directive, the Company must establish a credible process for tracking and calculating customers' energy burdens with the intention of using this information to develop more advanced and meaningful strategies to enhance customer engagement and support. The Department expects that the Company will provide a detailed household economic burden index analysis evaluating residential energy electric utility customer bills as percentages of household income by county and to provide the summary results of a detailed household burden index analysis by, at least census, block group. An electric customer's total bill should include net metering from solar, low-income discounts, and other factors impacting the bill. Additionally, the Company shall show the analysis by household income for the statewide median household income and 50 percent, 100 percent, and 200 percent of the Federal Poverty Guidelines. This level of granularity in the data is intended to provide a clearer picture of specific areas of the Company's service territory with higher-than-average energy burden. The Department recognizes that for the beginning of this process, we are primarily focused on electric utility bills generated by EDCs. Therefore, the Department will issue directives to National Grid (electric) and Unitil (electric) to include in their 2022 Annual Returns to the Department similar analyses as discussed above. As more homes convert to electric heat, the Department may consider requiring an analysis of energy burden between heating and non-heating customers.

D. Rate-by-Rate Analysis

1. Introduction

The Department must determine on a rate-class-by-rate-class basis, the proper level at which to set the customer charge and distribution charges for each rate class. D.P.U. 17-05-B at 260. The Department's long-standing policy regarding the allocation of class revenue requirements is that a company's total distribution costs should be allocated on the basis of EROR. D.P.U. 17-05-B at 260-261; D.T.E. 02-24/25, at 256. This allocation method satisfies the Department's rate design goal of fairness. D.P.U. 17-05-B at 261. Nonetheless, the Department must balance its goal of fairness with its goal of continuity.

D.P.U. 17-05-B at 261. For this balancing, we have reviewed the changes in total revenue requirement by rate class and bill impacts by consumption level within rate classes.

2. Rate Design Overview

The basic components of the Company's delivery service rates are the customer charge, which is a fixed monthly amount, and the distribution charge (Exh. ES-RDC-1, at 7). The distribution charge includes an energy (kWh) charge based on usage, and, for some C&I customers, can also include a demand (kW) charge (Exh. ES-RDC-1, at 7). The customer charge is intended to recover fixed costs that do not vary with customer electricity use, such as the costs of billing and metering (Exh. ES-RDC-1, at 7). Energy charges are a function of customer use, and, therefore, impact a customer's bill in proportion to how much electricity a customer has consumed in a given month (Exh. ES-RDC-1, at 7). A demand charge may be a per-kW charge or per-kilovolt-ampere ("kVA") charge that is billed on the customer's highest usage at a single point in time (Exh. ES-RDC-1, at 7).

Since fixed charges (i.e., customer charges) remain the same irrespective of usage, increases to fixed charges can have a negative bill impact on customers with low usage (Exh. ES-RDC-1, at 8). This impact may produce a high percentage bill impact, but not necessarily a large total dollar bill impact (Exh. ES-RDC-1, at 8). Conversely, higher customer charges benefit high volume users because a higher customer charge means a lower volumetric charge to recover the class revenue requirement, and, as such, fewer dollars need to be collected on a volumetric basis (Exh. ES-RDC-1, at 8). In addition, lower customer charges and higher volumetric rates may send price signals aligned with the Commonwealth's public policy objectives regarding on-site generation and energy efficiency. G.L. c. 164, § 141. Establishing the proper customer charge is a trade-off where the intra-class subsidization of costs between high- and low-consumption customers needs to be balanced against the customer bill impacts, as well as the relevant policy objectives under G.L. c. 164, § 141 (Exh. ES-RDC-1, at 8).

3. Residential Rates

a. Introduction

In D.P.U. 17-05-B at 89-92, the Department approved the consolidation of residential rates for all four legacy companies. Therefore, the Company has four residential rate classes offered across its EMA and WMA service areas: Rate R-1 is the residential non-heating rate class; Rate R-2 is the residential non-heating assistance rate class; Rate R-3 is the residential space heating rate class; and Rate R-4 is the residential space heating assistance rate class (Exhs. ES-RDC-1, at 16; ES-RDC-6, Sch. 1, at 8).

b. Company Proposal

i. Residential Rate R-1 and Residential Rate R-2

The Company's current residential Rate R-1 is available for all domestic purposes in individual private dwellings, individual apartments, or residential condominiums in which the principal means of heating the premises is not provided by permanently installed electric space heating equipment (Exh. ES-RDC-6, Sch. 2, at 53). The Company's current residential Rate R-2 is available to any Rate R-1 customer that is eligible for the Low-Income Home Energy Assistance Program ("LIHEAP"), or its successor program, or receives any means-tested public benefit for which eligibility does not exceed 200 percent of the federal poverty level based on a household's gross income (Exh. ES-RDC-6, Sch. 2, at 55-57). Currently residential Rate R-1 and R-2 customers have a customer charge of $7.00 per month and an energy charge of $0.05165 per kWh (Exh. ES-RDC-2, Sch. 11, at 1 (Rev. 3)). The Company proposes to increase the monthly customer charge to $10.00 per month, and energy charge to $0.06107 per kWh (Exh. ES-RDC-2, Sch. 1, at 1 (Rev. 3)).

ii. Residential Rate R-3 and Residential Rate R-4

The Company's current residential Rate R-3 is available for all domestic uses in a single private dwelling, in an individual apartment, or in a residential condominium where the principal means of heating the premises is provided by permanently installed electric space heating equipment (Exh. ES-RDC-6, Sch. 2, at 58). The Company's current residential Rate R-4 is available to any Rate R-3 customer that is eligible for LIHEAP, or its successor program, or receives any means-tested public benefit for which eligibility does not exceed 200 percent of the federal poverty level based on a household's gross income (Exh. ES-RDC-6, Sch. 2, at 60, 62). Currently Rate R-3 and R-4 customers have a customer charge of $7.00 per month and an energy charge of $0.04494 per kWh (Exh. ES-RDC-2, Sch. 11, at 2 (Rev. 3)). The Company proposes to increase the monthly customer charge to $10.00 per month, and the distribution energy charge to $0.05679 per kWh (Exh. ES-RDC-2, Sch. 1, at 1 (Rev. 3)).

c. Positions of the Parties

i. Attorney General

The Attorney General argues that the Department should reject the Company's proposed residential customer charge (Attorney General Brief at 166). According to the Attorney General, the proposed increase of $3.00, or 43 percent, from $7.00 to $10.00, is inconsistent with promoting energy efficiency because it reduces economic incentives for ratepayers to control monthly utility bills through energy efficiency and conservation efforts (Attorney General Brief at 166). In addition, the Attorney General contends that an increase in the residential customer charge is not necessary, as the Company already collects a significant portion of its fixed costs through the current customer charge (Attorney General Brief at 168). Finally, the Attorney General asserts that the proposed increase in residential customer charges will have a disproportionately adverse impact on low-income ratepayers and fixed-income ratepayers, creating equity concerns (Attorney General Brief at 169).

ii. DOER

DOER argues that the proposed increase in the customer charge is not necessary for the Company's revenue stability and would cause rate shocks for consumers if the energy charge is not also reduced, especially considering other price increases across the economy (DOER Brief at 18). Further, DOER contends that if revenue decoupling is eliminated in the future, the method by which the Company will recover costs will change, and an increase in volumetric sales could lead to a decreased need to collect fixed costs (DOER Brief at 19).

iii. Cape Light Compact

Cape Light Compact argues that the Company's proposed increase in the residential customer charge is significant and should be rejected (CLC Brief at 28). In particular, Cape Light Compact asserts that the impact of the proposed increase would be difficult for those on a fixed income and who are low-income or low-use customers with little load to shift (CLC Brief at 28-31, citing Exh. CLC-JDW-1, at 5). Cape Light Compact recommends that the Company phase in the increase by $1.00 per year over a three-year period to achieve greater stability for customers (CLC Brief at 31-32, citing Exh. CLC-KFG-1, at 11, Table 3). Cape Light Compact asserts that the deficiency in revenue from this phased-in approach could be recovered through the residential energy charge (CLC Brief at 32).

iv. Company

The Company argues that the proposed residential customer charge increases are necessary because current charges are below the embedded cost levels that represent the customer cost to serve or are required to align classes more closely in the various legacy service areas (Company Brief at 426, citing Exh. CLF-1-4). Further, the Company contends that customer charges have barely increased since 1998 despite the addition of other rates that have made the customer charge an increasingly minor part of the total customer bill (Company Brief at 426, citing Exh. ES-RDC-Rebuttal-1, at 5). In addition, the Company asserts that the proposed $10.00 customer charge represents only seven percent of the total bill for an average customer, while the current customer charge of $7.00 represents five percent of the total bill for an average customer (Company Brief at 426, citing

Exh. ES-RDC-Rebuttal-1, at 5). According to the Company, this comparison demonstrates that more than 90 percent of an average customer bill is volumetric under both proposed and current rates (Company Brief at 426, citing Exh. ES-RDC-Rebuttal-1, at 5). Thus, the Company asserts that it does not recover most of its fixed customer-related costs outside of customer volumetric charges and average customers will continue to have the ability to reduce a vast portion of their bill (Company Brief at 426, citing Exh. ES-RDC-Rebuttal-1, at 5). The Company contends that the proposed customer charge is not a dramatic increase and will not impede conservation, but it will improve efficiency by more properly assigning fixed costs to fixed charges (Company Brief at 426, citing Exh. ES-RDC-Rebuttal-1, at 5).

Further, the Company argues that its proposed increase to the residential customer charge is intended to send the correct price signal to customers and to stabilize customer costs and is not intended to maintain revenue stability for the Company (Company Brief at 427, citing Exh. ES-RDC-Rebuttal-1, at 5). Moreover, the Company contends that the increased customer charge to low-income customers will be mitigated by the proposed increase in the low-income discount to 42 percent from 36 percent (Company Brief at 427, citing Exhs. LI-ES 1-4; LI-ES 1-5; CLC-ES 5-1; CLC-ES 7-2). Finally, the Company asserts that the rate burden to lower-use customers is not increased significantly more than for higher-use customers because, as noted above, more than 90 percent of an average customer bill is volumetric under both proposed and current rates (Company Brief at 427, citing Exhs. LI-ES 1-4; LI-ES 1-5; CLC-ES 5-1; CLC-ES 7-2).

d. Analysis and Findings

In recent years, the Department has frequently required companies to set demand and energy volumetric rates based on the revenue requirement remaining after revenues from the proposed customer charges have been taken into consideration. See, e.g., D.P.U. 18-150, at 542-562; D.P.U. 17-05-B at 260-323. The Department is charged with reviewing the resulting rates that the customer will experience, as well as the associated bill impact from changes to those rates, requiring us to weigh the goals of fairness, efficiency, simplicity, stability, and continuity. D.P.U. 18-150, at 543; D.P.U. 17-05-B at 260. As discussed in numerous places in this Order, the Department considers multiple factors in making its decisions regarding allowable costs, the resulting change in rates, and the resulting customer bills. There is no single optimal method of setting rates that will impact all customers equally. The Department recognizes that some changes can have disproportionate impacts on different customers. For a product that is priced using both a fixed charge and a variable charge, all else equal, a customer with low usage will experience a greater impact related to an increase in that fixed charge than a customer with high usage. Similarly, all else equal, a customer with high usage will experience a greater impact related to an increase in the volumetric charge than a lower usage customer.

The Company has demonstrated that its customer charges represent a relatively small amount of the total bill and, as such, the proposed increases will still provide appropriate price signals to customers to encourage implementation of conservation measures to lower their overall bill (Exh. ES-RDC-Rebuttal-1, at 5). Further, as noted in Section XVII.C.3

above, the Department approved an increase in the low-income discount rate from 36 percent to 42 percent. We find that the increase in the low-income discount rate will assist in mitigating the bill impacts to low-income customers of any rate increase. Based on these considerations, we are not persuaded that a phase-in of the proposed increase to the customer charge is warranted.

According to the Company's ACOSS, the existing embedded customer charge for rate classes R-1 and R-2 is $10.73 per month (Exh. ES-ACOS-2, at 9 (Rev. 3)). Based on a review of embedded costs and the bill impacts on customers, the Department finds that a monthly customer charge of $10.00 for rate classes R-1 and R-2 best meets our rate design goals and objectives. Therefore, the Department approves a monthly customer charge of $10.00 for rate classes R-1 and R-2. The Company shall set the volumetric rate for rate classes R-1 and R-2 to recover the remaining class distribution revenue requirement approved in this Order.[212]

According to the Company's ACOSS, the existing embedded customer charge for rate classes R-3 and R-4 is $13.10 per month (Exh. ES-ACOS-2, at 9 (Rev. 3)). Based on a review of embedded costs and the bill impacts on customers, the Department finds that a monthly customer charge of $10.00 for rate classes R-3 and R-4 best meets our rate design goals and objectives. Therefore, the Department approves a monthly customer charge of

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[212] The Department also directs NSTAR Electric, when designing the rates for the individual rate classes, to truncate the variable per kWh charges after five decimal places and truncate the variable per kW demand charges after two decimal places so that rates are designed to collect no more than the allowed revenue requirement.

$10.00 for rate classes R-3 and R-4. The Company shall set the volumetric rate for rate classes R-3 and R-4 to recover the remaining class distribution revenue requirement approved in this Order.

4. Small General Service Rates

a. Introduction

As discussed in Section XVII.B.3.b above, the Department approved the Company's proposal to group customers with less than 100 kW of demand annually into a small general service rate group. In doing so, some customers currently served on certain rate classes moved to different rate classes to allow for this alignment, and the Department allowed the Company's proposal to cancel multiple rate classes. Further, as discussed in Section XVII.B.3.b above, the Department allowed the Company's proposal to eliminate seasonal rate offerings (except for Rate T-1), to eliminate the energy block rate design and some demand ratchets where currently used, and to introduce a non-demand rate pricing option for proposed Rate G-1 (Exh. ES-RDC-1, at 41).[213]

b. Boston Edison Service Area

i. Company Proposal

(A) Rate G-1 Demand and Non-Demand

NSTAR Electric proposes Rate G-1 to be available for all non-residential uses of electricity to all customers in the Boston Edison service area where the service voltage is less

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[213] In their next respective base distribution rate proceeding, the EDCs shall examine rate designs for all electric buildings to align with the Commonwealth's electrification policies.

than 14,000 volts and the load for billing purposes does not exceed or is estimated not to exceed 100 kW for twelve consecutive months (Exh. ES-RDC-6, Sch. 1, at 136). This offering will consist of two pricing options: (1) a non-demand pricing option, as currently exists for Rate G-1, and (2) a demand pricing option (Exhs. ES-RDC-1, at 44-45; ES-RDC-6, Sch. 1, at 136). The Company proposes that demand meters be installed for all new customers regardless of their elected price option but will assign new customers to the non-demand price option unless otherwise requested (Exh. ES-RDC-6, Sch. 1, at 136). Customers with demand that does not exceed 10 kW for twelve consecutive months may not elect the demand price option (Exh. ES-RDC-6, Sch. 1, at 136).

Currently, Rate G-1 non-demand customers have a monthly customer charge of $8.00, and summer and winter energy charges of $0.08267 per kWh and $0.05133 per kWh, respectively (Exh. ES-RDC-2, Sch. 12, at 1 (Rev. 3)). The Company proposes a monthly customer charge of $15.00 for the non-demand offering and an energy charge of $0.04874 for both summer and winter (Exh. ES-RDC-2, Sch. 12, at 1 (Rev. 3)).

Currently, Rate G-1 demand customers have a monthly customer charge of $11.00, summer and winter demand charges for customers with greater than 10 kW annual use of $0.97 per kW and $0.31 per kW, respectively, and declining block rate pricing for energy ranging from $0.02899 per kWh to $0.07679 per kWh for summer, and $0.02758 per kWh to $0.04778 per kWh for winter (Exh. ES-RDC-2, Sch. 12, at 1 (Rev. 3)). The Company proposes a monthly customer charge of $20.00 for the demand offering and a demand charge of $18.25 (Exh. ES-RDC-2, Sch. 1, at 1 (Rev. 3)).

As noted in Section XVII.B.3.b above, to align small C&I customers across the legacy companies, the Department allowed the Company's proposed transfer of some customers currently taking service under Rate G-2 and Rate T-2 to the newly introduced demand pricing option under Rate G-1. Further, the Department approved the Company's proposal to cancel current Rate G-2, given the alignment in definitions for small and medium rate classes. Current Rate G-2 customers have a customer charge of $18.00 per month, and a distribution demand charge for those using more than 10 kW annually of $22.90 per kW in the summer and $10.68 per kW in the winter (Exh. ES-RDC-2, Sch. 12, at 2-3 (Rev. 3)). Current Rate T-2 customers have monthly inclining block customer charges ranging from $27.00 to $360.00, summer demand charges of $22.21 per kW, and winter demand charges of $12.66 per kW (Exh. ES-RDC-2, Sch. 12, at 3 (Rev. 3)).

(B) Rate T-1 (Closed)

Rate T-1 is an optional TOU rate that is closed to new customers (Exh. ES-RDC-1, at 46). The rate is available for non-residential customers in the Boston Edison service area who take their electric service through a single meter, subject to the availability of TOU meters as determined by the Company (Exh. ES-RDC-6, Sch. 1, at 143). This rate is not available when a customer's load for billing purposes either exceeds or is estimated to exceed 10 kW in any billing month (Exh. ES-RDC-6, Sch. 1, at 143). This rate is used primarily by customers with standalone net metering facilities (Exh. ES-RDC-1, at 71).

Currently, Rate T-1 customers have a monthly customer charge of $10.00 and an energy charge of $0.17851 per kWh during the summer peak period[214] and $0.02353 per kWh during the summer off-peak period[215] (Exh. ES-RDC-2, Sch. 12, at 2 (Rev. 3)). Rate T-1 customers also have energy charges of $0.08369 per kWh and $0.02133 per kWh for the winter peak hours period and off-peak hours period, respectively (Exh. ES-RDC-2, Sch. 12, at 2 (Rev. 3)). The Company proposes to increase the monthly customer charge to $20.00 but make no changes to the current energy rates (Exh. ES-RDC-2, Sch. 1, at 2 (Rev. 3)). No party addressed these issues on brief.

ii. Analysis and Findings

According to the Company's ACOSS, the existing embedded customer charge for proposed Rate G-1 and Rate T-1 is $11.39 per month (Exh. ES-ACOS-2, at 9, (Rev. 3)). Based on a review of embedded costs and the bill impacts on customers, the Department finds that a monthly customer charge of $15.00 for the Rate G-1 non-demand offering best meets our rate design goals and objectives. Similarly, the Department finds that a monthly customer charge of $20.00 and demand charge of $18.25 per kW for the Rate G-1 demand

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[214] For Boston Edison Rate T-1, the Company defines the peak period as the hours between 9:00 a.m. and 6:00 p.m. on weekdays during the months of June through September and the hours between 8:00 a.m. and 9:00 p.m. during the months of October through May, when the peak period is the hours between 8 a.m. and 9 p.m. weekdays (Exh. ES-RDC-6, Sch. 2, at 77).

[215] For Boston Edison Rate T-1, the Company defines off-peak hours as those that are not peak hours, including all hours during twelve Massachusetts holidays (Exh. ES-RDC-6, Sch. 2, at 77-78).

offering meets our rate design goals and objectives. Therefore, the Department approves (a) a monthly customer charge of $15.00 for the Rate G-1 non-demand offering and (b) a monthly customer charge of $20.00 for the Rate G-1 demand offering. The Company shall set a single volumetric rate for Rates G-1 demand and non-demand options. For Rate T-1, the Department finds a monthly charge of $20.00 to be appropriate and consistent with our rate design goals and objectives, therefore, we approve it. The Company shall set volumetric rates to recover the remaining class distribution revenue requirements approved in this Order, keeping the energy charges for the peak and off-peak hours and for the summer and winter periods in proportion with current rates. Further, the Department accepts the cancellation of current Rate G-2, given the proposed common definition of a small general service customer.

c. Cambridge Electric Light Service Area

i. Company Proposal

(A) Rate G-1

In Section XVII.B.3.b above, the Department allowed the Company's proposed realignment and consolidation of Cambridge Electric Light Rate G-1 to serve current Rate G-0, Rate G-1, and Rate G-4 customers (Exh. ES-RDC-1, at 20).[216] Cambridge Electric Light Rate G-1 will be available for all non-residential uses of electricity to all customers in the Cambridge Electric Light service area where the service voltage is less than 13,800 volts and demand does not exceed or is estimated not to exceed 100 kW in each of

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[216] In addition, the Department allowed the Company's proposal to cancel Rate G-0 and Rate G-4 (Exhs. ES-RDC-1, at 20; ES-RDC-6, Sch. 1, at 152, 162).

twelve consecutive billing months (Exh. ES-RDC-6, Sch. 1, at 153). Current Rate G-0 has a customer charge of $5.00 and an energy charge of $0.03870 per kWh (Exh. ES-RDC-2, Sch. 12, at 4 (Rev. 3)). Current Rate G-1 has a customer charge of $8.00 and demand charges of $4.28 per kW for customers using 10 kW or less, and $7.98 for customers using more than 10 kW, as well as an energy charge of $0.01288 per kWh (Exh. ES-RDC-2, Sch. 12, at 4 (Rev. 3)). Current Rate G-4 has a customer charge of $12.00 per month and a demand charge of $4.74 per kW and an energy charge of $0.01188 per kWh (Exh. ES-RDC-2, Sch. 12, at 5 (Rev. 3)).

For proposed Rate G-1, the Company proposes a monthly customer charge of $15.00, no demand charge, and an energy charge of $0.03448 per kWh (Exh. ES-RDC-2, Sch. 1, at 1 (Rev. 3)).

(B) Rate G-5 (Closed)

Cambridge Electric Light Rate G-5 is proposed to be available only at existing service locations to customers in the Cambridge Electric Light service area who were taking service under this rate prior to December 1, 1985, for electric space heating through a separate meter where electricity is the sole means of heating the premises (Exh. ES-RDC-6, Sch. 1, at 163). Currently, customers taking service on Rate G-5 have a customer charge of $8.00 per month, as well as energy charges of $0.02024 per kWh for energy use equal to or less than 5,000 kWh, and $0.02659 per kWh for customers using more than 5,000 kWh per month (Exh. ES-RDC-2, Sch. 12, at 5 (Rev. 3)). The Company proposes to increase the customer charge to $15.00 per month and proposes an energy charge for all levels of use of $0.02527 per kWh (Exh. ES-RDC-2, Sch. 1, at 1 (Rev. 3)).

(C) Rate G-6 (Closed)

Cambridge Electric Light Rate G-6 is an optional TOU rate that is closed and used by standalone net metering customers (Exh. ES-RDC-1, at 47). The rate is available upon written application and the execution of an electric service agreement, for non-residential customers in the Cambridge Electric Light service area who take their electric service through a single meter, subject to the availability of TOU as determined by the Company (Exh. ES-RDC-6, Sch. 1, at 165). This rate is not available when a customer's load for billing purposes either exceeds or is estimated to exceed 10 kW in any three consecutive billing months (Exh. ES-RDC-6, Sch. 1, at 165). The current monthly customer charge for Rate G-6 is $9.00, and the energy charges for the peak load period ("peak use")[217] is $0.06346 per kWh, and for the low load period ("low load use")[218] is $0.02338 per kWh (Exh. ES-RDC-2, Sch. 12, at 4 (Rev. 3)). The Company proposes to increase the customer

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[217] For purposes of Cambridge Electric Light Rate G-6, the Company defines the peak load period as that portion of the year when eastern daylight savings time is in effect, the period beginning at 9:00 a.m. and ending at 6:00 p.m. on all weekdays, Monday through Friday (Exh. ES-RDC-6, Sch. 2, at 110). When eastern standard time is in effect, the peak load period is the period beginning at 4:00 p.m. and ending at 9:00 p.m. on all weekdays, Monday through Friday (Exh. ES-RDC-6, Sch. 2, at 110).

[218] For purposes of Cambridge Electric Light Rate G-6, the Company defines the low load period as all hours not included in the peak load period (Exh. ES-RDC-6, Sch. 2, at 110).

charge to $20.00 per month but proposes no changes to the current volumetric charges (Exh. ES-RDC-2, Sch. 1, at 1 (Rev. 3)). No party addressed these issues on brief.

ii. Analysis and Findings

According to the Company's ACOSS, the embedded customer charge for proposed Rate G-1, Rate G-4, and Rate G-6 is $23.03 per month (Exh. ES-ACOS-2, at 10 (Rev. 3)). The embedded customer charge for proposed Rate G-5 is $33.88 per month (Exh. ES-ACOS-2, at 10 (Rev. 3)). Based on a review of embedded costs and the bill impacts on customers, the Department finds that a monthly customer charge of $15.00 for Rate G-1 and Rate G-5 best meet our rate design goals and objectives. Therefore, the Department approves (a) a monthly customer charge of $15.00 for Rate G-1 and (b) a monthly customer charge of $15.00 for Rate G-5. For Rate G-1, the Company shall eliminate the current demand charge and recover the remaining class distribution revenue requirements approved in this Order using a single volumetric rate. For Rate G-5 the Company shall also implement a single volumetric rate to recover the remaining class distribution revenue requirements approved in this Order. In addition, for Rate G-6 the Department finds that a monthly customer charge of $20.00 also meets our rate design goals and objectives and, therefore, we approve it. For Rate G-6, the Company shall recover the remaining class distribution revenue requirements approved in this Order through the energy charges using the proposed method for establishing these rates.

d. Commonwealth Electric Service Area

i. Company Proposal

(A) Rate G-1

Commonwealth Electric Rate G-1 is proposed to be available to all customers in the South Shore, Cape Cod, and Martha's Vineyard service area except those customers whose load for billing purposes either exceeds or is estimated to exceed 100 kW in each of twelve consecutive billing months (Exh. ES-RDC-6, Sch. 1, at 183). The Company states that demand meters will be installed for all new customers (Exh. ES-RDC-6, Sch. 1, at 183). Commonwealth Electric Rate G-1 is proposed to serve customers currently taking service under both the annual and seasonal offerings, as well as current Rate G-5 customers (Exh. ES-RDC-1, at 72).[219] These rate classes currently have a monthly customer charge of $6.00 (Exh. ES-RDC-2, Sch. 12, at 6, 8 (Rev. 3)). Customers currently taking service under this offering have a demand charge of $5.59 per kW for customers using greater than 10 kW, as well as energy charges of $0.04684 per kWh for customers with less than or equal to 2,300 kWh of use, and $0.01269 per kWh for customers with greater than 2,300 kWh of use (Exh. ES-RDC-2, Sch. 12, at 6 (Rev. 3)). Current Rate G-1 for seasonal customers has a demand charge of $4.93 per kW for customers using greater than 10 kW, as well as energy charges of $0.08697 per kWh for customers with less than or equal to

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[219] In Section XVII.B.3.b above, the Department allowed the Company's consolidation and alignment plan, and, therefore, allowed the Company's proposal to cancel Rate G-5 (Exh. ES-RDC-1, at 72).

1,800 kWh of use and $0.02763 per kWh for customers with greater than 1,800 kWh of use (Exh. ES-RDC-2, Sch. 12, at 6 (Rev. 3)).

For proposed Rate G-1, the Company proposes to eliminate the seasonal offering and the demand charge; and set the monthly customer charge at $15.00 and energy charge at $0.03755 per kWh for all hours of use (Exhs. ES-RDC-1, at 47; ES-RDC-2, Sch. 1, at 1 (Rev. 3)).

(B) Rates G-7

Rate G-7 is an optional TOU rate offering available for all non-residential uses of electricity to customers in the South Shore, Cape Cod and Martha's Vineyard service area except those whose load for billing purposes either exceeds or is estimated to exceed 100 kW in each of twelve consecutive billing months (Exh. ES-RDC-6, Sch. 1, at 201). This rate currently serves annual as well as seasonal customers (Exh. ES-RDC-6, Sch. 1, at 201). The current Rate G-7 monthly customer charge is $10.00, and, for annual customers, the demand charge is $3.81 per kW, the peak use[220] energy charge is $0.02621 per kWh, and the low load use[221] energy charge is $0.01836 per kWh (Exh. ES-RDC-2, Sch. 12, at 7 (Rev. 3)).

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[220] For purposes of Commonwealth Electric Rate G-7, the Company defines the peak load period as that portion of the year when eastern daylight savings time is in effect, the period beginning at 9:00 a.m. and ending at 6:00 p.m. on all weekdays, Monday through Friday (Exh. ES-RDC-6, Sch. 2, at 110). When eastern standard time is in effect, the peak load period is the period beginning at 4:00 p.m. and ending at 9:00 p.m. on all weekdays, Monday through Friday (Exh. ES-RDC-6, Sch. 2, at 164).

[221] For purposes of Commonwealth Electric Rate G-7, the Company defines the low load period as all hours not included in the peak load period (Exh. ES-RDC-6, Sch. 2, at 164).

For current seasonal customers, the demand charge is $3.86 per kW, the peak use energy charge is $0.05113 per kWh, and the low load use energy charge is $0.04300 per kWh (Exh. ES-RDC-2, Sch. 12, at 7 (Rev. 3)).

The Company proposes to eliminate the seasonal offering and set the monthly customer charge at $20.00, the demand charge at $3.81 per kW, the peak use energy charge at $0.03747 per kWh, and the low load use energy charge at $0.02625 per kWh (Exhs. ES-RDC-1, at 47-48; ES-RDC-2, Sch. 1, at 1 (Rev. 3)). Furthermore, the Department allowed the Company's proposal to close Rate G-7 to curb the growth of discounted legacy rates and to facilitate alignment (Exh. ES-RDC-1, at 72).

(C) Rate G-4 (Closed)

Rate G-4 is closed to new customers (Exh. ES-RDC-1, at 48). It is available for general power purposes only at existing service locations to customers in the South Shore, Cape Cod, and Martha's Vineyard service area who were taking service under this rate schedule as of February 8, 1980 (Exh. ES-RDC-6, Sch. 1, at 194). This rate is not available for standby service in idle plants or buildings, or where operations have been reduced to a small part of normal capacity of the plant (Exh. ES-RDC-6, Sch. 1, at 194). For industrial service where the connected load is 50 horsepower or more, incidental lighting is allowed (Exh. ES-RDC-6, Sch. 1, at 194). The current monthly customer charge for Rate G-4 is $6.00, the demand charge is $1.99 per kW, and the energy charge is $0.02282 per kWh (Exh. ES-RDC-2, Sch. 12, at 8 (Rev. 3)). The Company proposes a monthly customer charge of $15.00, a demand charge of $2.17 per kW, and an energy charge of $0.02490 per kWh (Exh. ES-RDC-2, Sch. 1, at 1, (Rev. 3)).

(D) Rate G-6 (Closed)

Rate G-6 is also closed to new customers (Exh. ES-RDC-1, at 48). It is available only at existing service locations to customers in the South Shore, Cape Cod, and Martha's Vineyard service area who were taking service as of February 8, 1980, under an all-electric school rate schedule or under a special contract for all-electric school service (Exh. ES-RDC-6, Sch. 1, at 198). This rate is available for annual service in public and private school buildings where electricity supplies the total energy requirements of the premises served (Exh. ES-RDC-6, Sch. 1, at 198).

The current monthly customer charge for Rate G-6 is $30.00, and the energy charge is $0.01867 per kWh. The Company proposes a monthly customer charge of $15.00 and an energy charge of $0.01974 per kWh (Exh. ES-RDC-2, Sch. 1, at 1 (Rev. 3)). No party addressed these issues on brief.

ii. Analysis and Findings

According to the Company's ACOSS, the existing embedded customer charges for proposed Rate G-1 and Rate G-7 is $15.32 per month, and for Rate G-5 is $16.07 per month (Exh. ES-ACOS-2, at 10-11 (Rev. 3)). For proposed Rate G-4, the embedded monthly customer charge is $35.90, and for proposed Rate G-6 the embedded monthly customer charge is $41.33 (Exh. ES-ACOS-2, at 11 (Rev. 3)). Based on a review of embedded costs and the bill impacts on customers, the Department finds that a monthly customer charge of

$15.00 for Rate G-1, Rate G-4, and Rate G-6, as well as $20.00 for Rate G-7 best meet our rate design goals and objectives. Therefore, the Department approves (a) a monthly customer charge of $15.00 for Rate G-1, Rate G-4, and Rate G-6 and (b) a monthly customer charge of $20.00 for Rate G-7. As stated in Section XVII.B.3.b above, the Department approves the Company's proposal to eliminate the seasonal offerings under Rates G-1 and G-7. For Rate G-1, the Department also approves the Company's proposal to eliminate the demand charge as it meets the rate design goal of simplicity. Further, the Department approves the Company's proposed demand charges of $3.81 per kW for Rate G-7 customers and $2.17 per kW for customers taking service under Rate G-4 as they best meet our rate design goals and objectives at this time.

The Company shall recover the remaining distribution revenue requirement for Rate G-1 approved in this Order using a single volumetric rate. For Rate G-7, the Company shall change current peak use and low load use energy charges in proportion with current energy rates to collect the remaining distribution revenue requirement approved in this Order. For Rate G-4 and Rate G-6, the Company shall recover the remaining distribution revenue requirements approved in this Order for each class using a single volumetric rate for each rate class.

e. WMA Service Area

i. Company Proposal

(A) Rate 23 (Closed)

Rate 23 has not been available to new customers since February 1, 2011 (Exh. ES-RDC-6, Sch. 1, at 205). This rate is applicable to the use of electricity for water heating of any customer other than residential in the WMA service territory (Exh. ES-RDC-6, Sch. 1, at 205). This rate is available to residential customers where electricity supplies a portion of, but is not the sole source of, domestic hot water heating (Exh. ES-RDC-6, Sch. 1, at 205). It is also available for centrally supplied water heating in apartment buildings (Exh. ES-RDC-6, Sch. 1, at 205).

The monthly customer charge for Rate 23 is currently $17.00 and the energy charge is $0.03125 per kWh (Exh. ES-RDC-2, Sch. 12, at 9 (Rev. 3)). The Company proposes to increase the monthly customer charge to $20.00 and decrease the energy charge to $0.02356 per kWh (Exh. ES-RDC-2, Sch. 1, at 1 (Rev. 3)).

(B) Rate 24 (Closed)

Rate 24 is applicable to the use of electricity for lighting and incidental power in an edifice set apart exclusively for public worship and only for those customers in the WMA service territory already receiving service on this rate (Exh. ES-RDC-6, Sch. 1, at 208).

The monthly customer charge for Rate 24 is currently $65.00, the demand charge is $4.84 per kW for demand over 2 kW, and the energy charge is $0.00617 per kWh (Exh. ES-RDC-2, Sch. 12, at 9 (Rev. 3)). The Company proposes no change to the customer or demand charges and proposes to increase the energy charge to $0.00902 per kWh (Exh. ES-RDC-2, Sch. 1, at 1 (Rev. 3)).

(C) Rate G-1

In Section XVII.B.3.b above, the Department allowed the Company's consolidation and alignment proposal for Rate G-1 to serve those customers currently taking service under Rate G-0, as well as Rate T-0, Rate T-4, and Rate G-2 customers using less than or equal to 100 kW of demand (Exhs. ES-RDC-1, at 72-73; ES-RDC-6, Sch. 2, at 171). Therefore, we allowed the Company's proposal to rename current Rate G-0 as Rate G-1, and to cancel Rate T-0 (Exh. ES-RDC-1, at 72). This rate is applicable to all uses of electricity at a single location in the WMA service territory that does not exceed a demand of 100 kW (Exh. ES-RDC-6, Sch. 1, at 210). The Company states that demand meters will be installed for all new customers regardless of the elected price option (Exh. ES-RDC-6, Sch. 1, at 210). Further, NSTAR Electric states that all electricity delivered under this rate shall be measured through one metering equipment, except that, where the Company deems it impractical to deliver electricity through one service, or where more than one meter has been installed, then the measurement of the amount of electricity consumed may be by two or more meters (Exh. ES-RDC-6, Sch. 1, at 210). The Company states that all electricity supplied shall be for the exclusive use of the customer and shall not be resold (Exh. ES-RDC-6, Sch. 1, at 210). The Company further states that, with its permission, a customer may furnish electricity to persons or entities who occupy space in the building to which service is supplied hereunder, but on the express condition that the customer shall not resell, make a specific charge for, or re-meter (or sub-meter) or measure or control the use of, any of the electricity furnished (Exh. ES-RDC-6, Sch. 1, at 210). Finally, the Company states that all new customers will be assigned the non-demand price option unless otherwise requested by the customer, and that unmetered customers may not elect the demand price option (Exh. ES-RDC-6, Sch. 1, at 210).

The current monthly customer charge for Rate G-0 is $30.00 for metered customers and $15.00 for unmetered customers (Exh. ES-RDC-2, Sch. 12, at 10 (Rev. 3)). The demand charge for customers with demand more than 2 kW is $10.83 per kW and the energy charge is $0.00213 per kWh (Exh. ES-RDC-2, Sch. 12, at 10 (Rev. 3)). Current Rate T-0 is a TOU rate, with a current monthly customer charge of $30.00, a demand charge of $10.50 per kW for use over 2 kW, a peak period energy charge of $0.00329 per kWh, and an off-peak period energy charge of $0.00088 per kWh (Exh. ES-RDC-2, Sch. 12, at 11 (Rev. 3)). Current Rate T-4 is also a TOU rate,[222] with a monthly customer charge of $353.00, a demand charge for customers using less than or equal to 50 kW of $1.99 per kW, a demand charge of $9.37 per kW for customers using more than 50 kW, a peak energy charge of $0.00315 per kWh, and an off-peak energy charge of $0.00089 per kWh (Exh. ES-RDC-2, Sch. 12, at 12 (Rev. 3)). Current Rate G-2 has a monthly customer charge of $353.00, a demand charge of $1.99 per kW for use equal to or less than 50 kW, a

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[222] For Rate T-4 and all WMA TOU rates, the Company defines the peak period as weekdays from noon to 8 p.m., while all other hours are the off-peak period (Exh. ES-RDC-6, Sch. 2, at 178, 182, 186).

demand charge of $9.37 per kW for use over 50 kW, and an energy change of $0.00210 per kWh (Exh. ES-RDC-2, Sch. 12, at 12 (Rev. 3)).

The Company proposes the new Rate G-1 offerings to have a monthly customer charge of $30.00 for metered customers and $15.00 for unmetered customers (Exh. ES-RDC-2, Sch. 1, at 1 (Rev. 3)). For non-demand Rate G-1 customers, the Company proposes an energy charge of $0.03614 per kWh. For demand Rate G-1 customers, the Company proposes a demand charge for customers using more than two kW of $10.83 per kW and an energy charge of $0.00434 per kWh (Exh. ES-RDC-2, Sch. 1, at 1 (Rev. 3)). No party addressed these issues on brief.

ii. Analysis and Findings

According to the Company's ACOSS, the existing embedded monthly customer charge for proposed Rate 23 is $20.00 and the embedded monthly customer charge for proposed Rate 24 is $50.08 (Exh. ES-ACOS-2, at 11 (Rev. 3)). For proposed Rate G-1, the embedded monthly customer charge is $26.49 per month (Exh. ES-ACOS-2, at 12 (Rev. 3)). Based on a review of embedded costs and the bill impacts on customers, the Department finds that the proposed monthly customer charge of $20.00 for Rate 23 and $65.00 for Rate 24 best meets our rate design goals and objectives and, therefore, are approved. Similarly, monthly customer charges of $30.00 for metered and $15.00 for unmetered Rate G-1 customers best meets our rate design goals and objectives and, therefore, are approved.

The Department also finds that the proposed demand charge of $4.84 per kW for Rate 24 customers using more than two kW meets our rate design goals and objectives and, therefore, is approved. Similarly, for the Rate G-1 demand offering, the Department approves the Company's proposed demand charge of $10.83 per kW for customers using more than two kW as it is equal to the current charge for customers taking service under Rate G-0, and, therefore, meets the Department's goal of continuity. Further, the Company shall set energy rates for Rate 23, Rate 24, and Rate G-1 to recover each class's remaining class distribution revenue requirements approved in this Order.

5. Medium General Service Rates

a. Introduction

As previously mentioned, in Section XVII.B.3.b the Department accepted the Company's proposal to group customers with less than 100 kW of demand annually into a small general service rate group (Exh. ES-RDC-1, at 19). In doing so, the Company moved some customers previously considered to be in the small C&I rate group into the medium C&I rate group (Exh. ES-RDC-1, at 19-20). Therefore, some customers currently served at rates previously defined as small and medium C&I will move to different rate classes to allow for this alignment (Exh. ES-RDC-1, at 19-20). Generally, the definition for the medium C&I rate group is customers with demand greater than 100 kW that are not otherwise served by a large C&I rate class (Exh. ES-RDC-1, at 20). Similar to its approach to small C&I rates, the Department allowed the Company's proposal to eliminate seasonal pricing in the Boston Edison service area and to eliminate most instances of demand block design where used (Exh. ES-RDC-1, at 50).

b. Boston Edison Service Area

i. Company Proposal

(A) Rate G-2

Above, the Department allowed the Company to rename current Rate T-2 as Rate G-2. Rate G-2 is available for all non-residential uses of electricity to all customers in the Boston Edison service area where the service voltage is less than 14,000 volts and the demand is equal to or greater than 100 kW for twelve consecutive months (Exhs. ES-RDC-1, at 20; ES-RDC-6, Sch. 1, at 146). Currently, Rate T-2 has a four-block customer charge ranging from $27.00 to $360.00 per month, a summer period demand charge of $22.21 per kW, and a winter period demand charge of $12.66 per kW (Exh. ES-RDC-2, Sch. 13, at 2 (Rev. 3)). The Company proposes no changes to the monthly customer charges for the first three blocks, and to increase the fourth block from $360.00 per month to $370.00 per month (for customers using more than 1,000 kW) (Exh. ES-RDC-2, Sch. 1, at 2 (Rev. 3)). Further, the Company proposes a single demand charge of $17.31 per kW (Exh. ES-RDC-2, Sch. 1, at 2 (Rev. 3)). No party addressed this issue on brief.

ii. Analysis and Findings

According to the Company's ACOSS, the embedded customer charge for proposed Rate G-2 is $66.07 per month (Exh. ES-ACOS-2, at 9 (Rev. 3)). Based on a review of embedded costs and the bill impacts on customers, the Department finds that the current monthly customer charge structure, $27.00 for customers using up to 150 kW, $110.00 for customers using more than 150 kW but equal to or less than 300 kW, $160.00 for customers using more than 300 kW but less than or equal to 1,000 kW, and $370.00 for customers using more than 1,000 kW, for current Rate T-2 best meets our rate design goals and objectives and, therefore, we approve these customer charges for proposed Rate G-2. The Company shall set a single demand rate for all Rate G-2 customers to recover the remaining class revenue requirement approved in this Order.

c. Cambridge Electric Light Service Area

i. Company Proposal

(A) Rate G-2

Cambridge Electric Light Rate G-2 is available for all uses of electricity to customers in the Cambridge Electric Light service area where the service voltage is less than 13,800 volts and the demand exceeds or is estimated to exceed 100 kW for at least twelve consecutive billing months (Exh. ES-RDC-6, Sch. 1, at 155). The current monthly customer charge for Rate G-2 is $97.00, the demand charge for customers using less than or equal to 100 kVA is $4.63 per kVA, and $5.73 per kVA for customers using more than 100 kVA, and the energy charge is $0.01085 per kWh (Exh. ES-RDC-2, Sch. 13, at 3 (Rev. 3)). The Company proposes to increase the monthly customer charge to $110.00, to broaden the current demand charge of $4.63 per kVA to all customers taking service under this rate, and to increase the energy charge to $0.01479 per kWh (Exh. ES-RDC-2, Sch. 1, at 2 (Rev. 3)). No party addressed this issue on brief.

ii. Analysis and Findings

According to the Company's ACOSS, the existing embedded customer charge for proposed Rate G-2 is $89.69 per month (Exh. ES-ACOS-2, at 10 (Rev. 3)). Based on a review of embedded costs and the bill impacts on customers, the Department finds that the proposed monthly customer charge of $110.00 best meets our rate design goals and objectives and, therefore, is approved. The Company shall set the demand charge to $4.63 per kW, as proposed, as it is equal to the current first block demand charge and therefore meets our goal of continuity. The Company shall further develop a single energy charge to recover the remaining class distribution revenue requirement approved in this Order.

d. Commonwealth Electric Service Area

i. Company Proposal

(A) Rate G-2

Commonwealth Electric Rate G-2 is a TOU rate, available for all uses of electricity to customers in the South Shore, Cape Cod, and Martha's Vineyard service area with demands in excess of 100 kW but not greater than 500 kW for at least twelve consecutive months (Exh. ES-RDC-6, Sch. 1, at 186). The current monthly customer charge for Rate G-2 is $370.00, the demand charge is $1.78 per kW, and the energy charges are $0.02076 per kWh for peak load period, $0.01747 per kWh for low load period A, and $0.01133 per kWh for low load period B[223] (Exh. ES-RDC-2, Sch. 13, at 5 (Rev. 3)). The Company proposes to maintain the current monthly customer charge, set the demand charge to $3.02 per kW, and set the energy charge for all hours to $0.01401 per kWh (Exh. ES-RDC-2, Sch. 1, at 2 (Rev. 3)). No party addressed this issue on brief.

ii. Analysis and Findings

According to the Company's ACOSS, the embedded customer charge for proposed Rate G-2 is $205.68 per month (Exh. ES-ACOS-2, at 10 (Rev. 3)). Based on a review of embedded costs and the bill impacts on customers, the Department finds that the proposed monthly customer charge of $370.00 best meets our rate design goals and objectives and,

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[223] The Company defines the load periods for this rate as follows:

> Peak Load Period: During that portion of the year when eastern daylight savings time is in effect, the period beginning at 9:00 a.m. and ending at 6:00 p.m. on all weekdays, Monday through Friday. During that portion of the year when eastern standard time is in effect, the period beginning at 4:00 p.m. and ending at 9:00 p.m. on all weekdays, Monday through Friday.
>
> Low Load Period: All hours not included in the Peak Load Period. The Low Load Period shall be further divided into 2 separate time periods as follows:
>
> Low Load Period A: All hours not included in the Peak Load Period or Low Load Period B.
>
> Low Load Period B: During both eastern daylight savings time and eastern standard time, the period beginning at 10:00 p.m. and ending at 7:00 a.m. on all weekdays, Monday through Friday, and all hours on Saturday and Sunday.

(Exh. ES-RDC-6, Sch. 2, at 140).

therefore, is approved. The Department also finds that the proposed demand charge of $3.02 per kW meets our rate design goals and objectives and, therefore, is approved. The Company shall develop a single volumetric rate for Rate G-2 to recover the remaining class revenue requirement approved in this Order.

e. WMA Service Area

i. Company Proposal

(A) Rate G-2

WMA Rate G-2 is available only to the entire use of electricity at a single location in the WMA service area with demand use greater than 100 kW, but not in excess of 349 kW (Exh. ES-RDC-6, Sch. 1, at 214). All electricity use is required to be measured through one meter, except that, where the Company deems it impractical to deliver electricity through one service, or where more than one meter has been installed, then the measurement of electricity use may be by two or more meters (Exh. ES-RDC-6, Sch. 1, at 214). All electricity supplied is required to be for the exclusive use of the customer and cannot be resold (Exh. ES-RDC-6, Sch. 1, at 214). With the approval of the Company, the customer may furnish electricity to persons or entities who occupy space in the building to which service is supplied hereunder, but on the express condition that the customer shall not resell, make a specific charge for, or re-meter (or sub-meter) or measure or control the use of, any of the electricity so furnished (Exh. ES-RDC-6, Sch. 1, at 214). Rate 23 may be used in conjunction with this rate and is separately billed (Exh. ES-RDC-6, Sch. 1, at 214).

Rate G-2 is proposed to serve customers using more than 100 kW of demand from current Rate G-0 and Rate G-2 (Exh. ES-RDC-1, at 61, 63).

The current monthly customer charge for Rate G-0 is $30.00 for metered service and $15.00 for unmetered service, the demand charge is $10.83 per kW for customers with demand greater than 2 kW, and the energy charge is $0.00213 per kWh (Exh. ES-RDC-2, Sch. 13, at 5 (Rev. 3)). The current monthly customer charge for Rate G-2 is $353.00, the demand charge is $1.99 per kW for demand less than or equal to 50 kW, $9.37 per kW for demand over 50 kW, and the energy charge is $0.00210 per kWh (Exh. ES-RDC-2, Sch. 13, at 6 (Rev. 3)). For Rate G-2 the Company proposes a monthly customer charge of $110.00, a demand charge of $9.37 per kW, and an energy charge of $0.00417per kWh (Exh. ES-RDC-2, Sch. 1, at 2 (Rev. 3)).

(B) Rate T-4

WMA Rate T-4 is a TOU offering applicable only to the entire use of electricity at a single location in the WMA service area, for demand greater than 100 kW but not to exceed 349 kW (Exh. ES-RDC-6, Sch. 1, at 217). All electricity delivered is required to be measured through one meter (Exh. ES-RDC-6, Sch. 1, at 217). Also, all electricity supplied is required to be for the exclusive use of the customer and shall not be resold (Exh. ES-RDC-6, Sch. 1, at 217). With the approval of the Company, the customer may furnish electricity to persons or concerns who occupy space in the building to which service is supplied hereunder, but on the express condition that the customer shall not resell, make a specific charge for, or re-meter (or sub-meter) or measure, or control the use of, any of the electricity so furnished (Exh. ES-RDC-6, Sch. 1, at 217). Rate T-4 is proposed to serve customers using more than 100 kW of demand from current Rates T-0 and T-4 (Exh. ES-RDC-1, at 63).[224]

The current monthly customer charge for Rate T-0 is \$30.00, the demand charge is \$10.50 per kW for customers with demand greater than 2 kW, the peak energy charge is \$0.00329 per kWh, and the off-peak energy charge is \$0.00088 per kWh (Exh. ES-RDC-2, Sch. 13, at 6 (Rev. 3)). The current monthly customer charge for Rate T-4 is \$353.00, the demand charge is \$1.99 per kW for demand under or equal to 50 kW, and \$9.37 per kW for demand over 50 kW, the peak energy charge is \$0.00315 per kWh, and the off-peak energy charge is \$0.00089 per kWh (Exh. ES-RDC-2, Sch. 13, at 7 (Rev. 3)). For Rate T-4 the Company proposes a monthly customer charge of \$110.00, a demand charge of \$9.37 per kW, a peak energy charge of \$0.00891 per kWh, and an off-peak energy charge of \$0.00252 per kWh (Exh. ES-RDC-2, Sch. 1, at 2 (Rev. 3)). No party addressed these issues on brief.

ii. Analysis and Findings

According to the Company's ACOSS, the embedded customer charge for proposed Rate G-2 and Rate T-4 is \$122.79 per month (Exh. ES-ACOS-2, at 12 (Rev. 3)). Based on a review of embedded costs and the bill impacts on customers, the Department finds that the proposed monthly customer charge of \$110.00 best meets our rate design goals and

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[224] As noted above, the Department approved the cancellation of Rate T-0.

objectives and, therefore, is approved for each rate. The Company shall set the demand charge, as proposed, to $9.37 per kW as this is less than or equal to all current demand charges for most of the relevant customers, and therefore meets our goal of continuity. For Rate G-2 the Company shall set the energy charge to recover the remaining class distribution revenue requirement approved in this Order. For Rate T-4 to recover the remaining class distribution revenue requirement approved in this Order, the Company shall set the peak and off-peak energy charges such that they maintain the same ratio to the current energy charges.

6. Large General Service Rates

a. Introduction

Similar to the medium C&I rate grouping, in Section XVII.B.3.b above, the Department allowed the Company's proposal to eliminate seasonal pricing and eliminate the demand block design where used (Exh. ES-RDC-1, at 53). The rate structure for Boston Edison and Cambridge Electric Light will not change (Exh. ES-RDC-1, at 18).

b. Boston Edison Service Area

i. Company Proposal

(A) Rate G-3

Boston Edison Rate G-3 is available for all use at a single location in the Boston Edison service area on contiguous private property if service is supplied to the customer and metered at 14,000 volts nominal or greater and if the customer furnishes, installs, owns, and maintains at its expense all protective devices, transformers, and other equipment required by the Company (Exh. ES-RDC-6, Sch. 1, at 140). The current monthly customer charge for Rate G-3 is $250.00, the summer period demand charge is $16.60 per kW, and the winter period demand charge is $9.78 per kW (Exh. ES-RDC-2, Sch. 14, at 1 (Rev. 3)). The Company proposes to increase the monthly customer charge to $370.00 and to implement a single demand charge of $15.34 per kW (Exh. ES-RDC-2, Sch. 1, at 2 (Rev. 3)).

(B) Rate WR

Rate WR is available for electricity supplied and delivered in bulk for the purpose of construction and operation of the Deer Island Wastewater Treatment Facility from NSTAR Electric's K Street Transmission Station (Exh. ES-RDC-6, Sch. 1, at 149). The customer charge is currently $150.48 per month and there are no volumetric charges (Exh. ES-RDC-2, Sch. 14, at 1 (Rev. 3)). The Company proposes to increase the customer charge to $157.16 per month (Exh. ES-RDC-2, Sch. 1, at 2 (Rev. 3)). No party addressed these issues on brief.

ii. Analysis and Findings

According to the Company's ACOSS, the existing embedded customer charge for proposed Rate G-3 is $129.72 per month (Exh. ES-ACOS-2, at 9 (Rev. 3)). The existing embedded monthly customer charge for proposed Rate WR is $127.32 (Exh. ES-ACOS-2, at 9 (Rev. 3)). Based on a review of embedded costs and the bill impacts on customers, the Department finds that the proposed monthly customer charge of $370.00 for Rate G-3 best meets our rate design goals and objectives and, therefore, is approved. The Company shall set a single demand rate for Rate G-3 to recover the remaining class distribution revenue requirement for Rate G-3 approved in this Order. Further, the Company shall set a single customer charge for Rate WR to recover the class revenue requirement as approved in this

Order. Such rate design satisfies our simplicity goal, as well as our continuity goal because it produces bill impacts that are moderate and reasonable, considering the size of the increase.

c. Cambridge Electric Light Service Area

i. Company Proposal

(A) Rate G-3

Cambridge Electric Light Rate G-3 is available for all uses of electricity to customers in the Cambridge Electric Light service area whose metered load exceeds or is estimated to exceed 100 kW for at least twelve consecutive billing months and the service voltage is 13,800 volts or higher (Exh. ES-RDC-6, Sch. 1, at 159). The current monthly customer charge for Rate G-3 is $97.00, the demand charge is $4.74 per kVA for customers with load greater than 100 kVA of demand, and the energy charge at $0.00381 per kWh (Exh. ES-RDC-2, Sch. 14, at 2 (Rev. 3)). The Company proposes to increase the monthly customer charge to $370.00, set the demand charge for all levels of use at $5.92 per kW, and to maintain the energy charge at $0.00381 per kWh (Exh. ES-RDC-2, Sch. 1, at 2 (Rev. 3); Sch. 14, at 2 (Rev. 3)).

(B) Rate SB-1/MS-1/SS-1 (Closed)

Rate SB-1 is a closed rate for customers with a written application and execution of an electric service agreement, for those in the Cambridge Electric Light service area with an alternative source of power who requests firm delivery of standby service and for whom the Company has an obligation to serve (Exh. ES-RDC-6, Sch. 1, at 168). The Company must have the ability to meter the alternative source of power (Exh. ES-RDC-6, Sch. 1, at 168). Standby service is intended to deliver to the customer a replacement supply of power when the customer's alternative source of power is either partially or totally unavailable (Exh. ES-RDC-6, Sch. 1, at 168). A customer requesting standby service is required to take service under this rate schedule if the customer's alternative source of power (1) exceeds 100 kW, and (2) supplies at least 20 percent of the customer's total integrated electrical load (Exh. ES-RDC-6, Sch. 1, at 168).

Rate MS-1 is a closed rate for customers with a written application and execution of an electric service agreement, for those in the Cambridge Electric Light service area with an alternative source of power who requests delivery of maintenance service, and for whom the Company has an obligation to serve (Exh. ES-RDC-6, Sch. 1, at 173). The Company must have the ability to meter the alternative source of power. Maintenance service is intended to deliver to the customer electric energy and capacity to replace energy and capacity ordinarily generated by the facilities that make up the customer's alternative source of power when such facilities are withdrawn from service for maintenance scheduled in accordance with defined provisions (Exh. ES-RDC-6, Sch. 1, at 173). A customer requesting maintenance service is required to take service under this rate schedule if the customer's alternative source of power (1) exceeds 100 kW, and (2) supplies at least 20 percent of the customer's total integrated electrical load (Exh. ES-RDC-6, Sch. 1, at 173).

Rate SS-1 is a closed rate for customers with a written application and execution of an electric service agreement, for those in the Cambridge Electric Light service area with an alternative source of power in operation prior to October 31, 2003, and for whom the Company has an obligation to serve (Exh. ES-RDC-6, Sch. 1, at 178). The Company must have the ability to meter the alternative source of power (Exh. ES-RDC-6, Sch. 1, at 178). Supplemental service is intended to deliver power to supplement the output of the customer's alternative source of power where the alternative source of power is less than the customer's maximum electrical load (Exh. ES-RDC-6, Sch. 1, at 178). A customer requesting supplemental service is required to take service under this rate schedule if the customer's alternative source of power (1) exceeds 100 kW, and (2) supplies at least 20 percent of the customer's total integrated electrical load (Exh. ES-RDC-6, Sch. 1, at 173).

Proposed rates Rate SB-1 and Rate MS-1 have a current monthly customer charge of $781.00 (Exh. ES-RDC-2, Sch. 14, at 2 (Rev. 3)). The standby demand charge for these rate classes is $6.48 per kW (Exh. ES-RDC-2, Sch. 14, at 2 (Rev. 3)). The supplemental demand charge for Rate SS-1, for customers with demand greater than 100 kVA, is $4.74 per kVA (Exh. ES-RDC-2, Sch. 14, at 2 (Rev. 3)). The supplemental energy charge for Rate SS-1 is equal to the energy charge for the otherwise applicable rate schedule, or Rate G-3, which is currently $0.00381 per kWh (Exh. ES-RDC-2, Sch. 14, at 2 (Rev. 3)). The Company proposes to increase the standby demand charge for Rates SB-1 and MS-1 to $7.59 per kW and the supplemental demand charge for Rate SS-1 to $5.92 per kVA, assuming the otherwise applicable rate class for the supplemental service customer is Rate G-3, for all demand levels (Exh. ES-RDC-2, Sch. 1, at 2 (Rev. 3)). The Company proposes to maintain the current customer charge and supplemental distribution energy charge (Exh. ES-RDC-2, Sch. 1, at 2 (Rev. 3)). No party addressed these issues on brief.

ii. Analysis and Findings

According to the Company's ACOSS, the existing embedded customer charge for proposed Rate G-3 is $97.10 per month (Exh. ES-ACOS-2, at 10 (Rev. 3)). Based on a review of embedded costs and the bill impacts on customers, the Department finds that the proposed monthly customer charge of $370.00 best meets our rate design goals and objectives and, therefore, is approved. The Company shall set the demand charge as proposed to $5.92 per kW, as this also best meets our rate design goals and objectives at this time. The Company shall develop a single energy rate for Rate G-3 to recover the remaining class revenue requirement for Rate G-3 approved in this Order. The Department further approves the Company's current and proposed monthly customer charge of $781.00 for Rate SB-1 and Rate MS-1. The Company shall set a single demand charge to recover the remaining class revenue requirement approved in this Order for Rate SB-1 and a single demand charge to recover the remaining class revenue requirement approved in this Order for Rate MS-1. Rate SS-1 shall be charged using the rates approved for the otherwise applicable rate, usually Rate G-3.[225]

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[225] The Department notes that the Company's proposed Rate SS-1 tariff appears to incorrectly refer to "Standby Service" in the last sentence of the Availability clause (Exh. ES-RDC-6, Sch. 1, at 178). The Company is directed to make any necessary corrections to this sentence in its compliance filing.

d. Commonwealth Electric Service Area

i. Company Proposal

(A) Rate G-3

Commonwealth Electric Rate G-3 is available for all uses of electricity to customers in the South Shore, Cape Cod, and Martha's Vineyard service area who establish demands in excess of 500 kW for at least twelve consecutive months (Exh. ES-RDC-6, Sch. 1, at 190). The current monthly customer charge for Rate G-3 is $930.00, the demand charge is $1.01 per kVA, the peak load energy charge is $0.01443 per kWh, the low load A period energy charge is $0.01328 per kWh, and the low load B period energy charge is $0.00919 per kWh (Exh. ES-RDC-2, Sch. 12, at 3 (Rev. 3)). The Company proposes to maintain the monthly customer charge at $930.00, increase the demand charge to $3.33 per kW, and implement a single energy charge for all hours of $0.01156 per kWh (Exh. ES-RDC-2, Sch. 1, at 2 (Rev. 3)). No party addressed this issue on brief.

ii. Analysis and Findings

According to the Company's ACOSS, the existing embedded customer charge for proposed Rate G-3 is $494.05 per month (Exh. ES-ACOS-2, at 11 (Rev. 3)). Based on a review of embedded costs and the bill impacts on customers, the Department finds that maintaining the monthly customer charge of $930.00, as proposed, and a demand charge of $3.33 per kW best meet our rate design goals and objectives and, therefore, are approved. Finally, the Company shall develop a single energy rate to recover the remaining class distribution revenue requirement for Rate G-3 approved in this Order.

e. WMA Service Area

i. Company Proposal

(A) Rate G-3

Proposed WMA Rate G-3 is applicable to current customers taking service under Rate T-2 (Exh. ES-RDC-1, at 65). This proposed rate class is only for use of electricity at a single location in the WMA service area. All electricity is required to be measured through a single TOU meter installed by the Company, except that, where the Company deems it impractical to deliver electricity through one service, or where more than one meter has been installed, then the measurement of electricity may be by two or more meters (Exh. ES-RDC-6, Sch. 1, at 220). All electricity supplied shall be for the exclusive use of the customer and shall not be resold (Exh. ES-RDC-6, Sch. 1, at 220). With the approval of the Company, the customer may furnish electricity to persons or concerns who occupy space in the building to which service is supplied, but on the express condition that the customer shall not resell, make a specific charge for, or re-meter (or sub-meter) or measure, or control the use of, any of the electricity so furnished (Exh. ES-RDC-6, Sch. 1, at 220).

The current monthly customer charge for Rate T-2 is a three-block rate, ranging from \$760.00 to \$2,700.00 (Exh. ES-RDC-2, Sch. 14, at 3 (Rev. 3)). The current demand charge is \$7.29 per kW, the current peak energy charge is \$0.00297 per kWh, and the current off-peak energy charge is \$0.00087 per kWh (Exh. ES-RDC-2, Sch. 14, at 3 (Rev. 3)). For Rate G-3, the Company proposes to maintain the existing customer charges and energy charges for current Rate T-2, as well as proposes to increase the distribution demand charge to $10.28 per kW (Exh. ES-RDC-2, Sch. 1, at 2 (Rev. 3)).

(B) Rate T-5

Rate T-5 is only available where the entire use of electricity is at a single location in the WMA service area (Exh. ES-RDC-6, Sch. 1, at 223). All electricity is measured through a single TOU meter installed by the Company, except that, where the Company deems it impractical to deliver electricity through one service, or where more than one meter has been installed, then the measurement of electricity may be by two or more meters (Exh. ES-RDC-6, Sch. 1, at 223). Also, all electricity supplied is required to be for the exclusive use of the customer and shall not be resold (Exh. ES-RDC-6, Sch. 1, at 223). With the approval of the Company, the customer may furnish electricity to persons or concerns who occupy space in the building to which service is supplied hereunder, but on the express condition that the customer shall not resell, make a specific charge for, or re-meter (or sub-meter) or measure or control the use of any of the electricity so furnished (Exh. ES-RDC-6, Sch. 1, at 223).

The current customer charge for Rate T-5 is $3,800.00 per month and the current demand charge is $5.18 per kW (Exh. ES-RDC-2, Sch. 14, at 4 (Rev. 3)). The Company also has a peak energy charge of $0.00296 per kWh and an off-peak energy charge of $0.00087 per kWh (Exh. ES-RDC-2, Sch. 14, at 4 (Rev. 3)). The Company proposes to maintain the current customer charge and off-peak energy charge but increase the demand charge to \$8.08 per kW and to increase the peak energy charge to \$0.00297 per kWh (Exh. ES-RDC-2, Sch. 1, at 2 (Rev. 3)). No party addressed these issues on brief.

ii. Analysis and Findings

According to the Company's ACOSS, the existing embedded customer charge for proposed Rate G-3 (i.e., current Rate T-2) is \$432.36 per month and for proposed Rate T-5 is \$1,910.10 per month (Exh. ES-ACOS-2, at 12 (Rev. 3)). Based on a review of embedded costs and the bill impacts on customers, the Department finds that the proposed monthly customer charges of \$760.00 for use between 350 kW and 1,000 kW, \$1,625.00 for customers using equal to or greater than 1,000 kW but less than 1,500 kW, and \$2,700.00 for customers using equal to or greater than 1,500 kW but less than 2,500 kW for proposed Rate G-3 and \$3,800.00 for Rate T-5 best meet our rate design goals and objectives. Therefore, the Department approves each of these monthly customer charges. The Company shall develop separate demand charges for Rate G-3 and Rate T-5, as well as peak and off-peak energy rates for both Rate G-3 and Rate T-5 together, to recover the remaining class distribution revenue requirements approved in this Order in proportion with the current energy rates.

7. Streetlighting and LED Streetlight Rates

a. Introduction

The Company proposes new rate design for Rates S-1 and S-2; Company and customer-owned streetlights, respectively (Exh. ES-RDC-1, at 65). The Company states that currently, similar to distribution rates for other customers, streetlight rates contain customer and demand components that represent the cost of service to provide them (Exh. ES-RDC-1, at 65-66). In addition, streetlight rates have direct assigned costs that constitute a facilities charge, which differentiates the rates for Company-owned streetlights from customer-owned streetlights (Exh. ES-RDC-1, at 66). The Company proposes to use the total costs for customer, demand, O&M, and facility components for Rate S-1, and the total costs for customer and demand for Rate S-2 (Exh. ES-RDC-1, at 66).

For Rate S-1, the Company proposes to adjust all rates by the percentage needed to reach the target revenue requirement (Exh. ES-RDC-1, at 66). Specifically, for Rate S-1, the Company proposes to increase the rates for each luminaire, pole, and accessory by 19.9 percent to meet the adjusted class target revenue for Rate S-1 (Exhs. ES-RDC-1, at 66; ES-RDC-5, Sch. 1 (Rev. 3)). The class target revenue requirement was adjusted to exclude the proposed revenues from LED lights (Exh. ES-RDC-5, Sch. 2, at 2-4 (Rev. 3)).

As LED light pricing has decreased in recent years, the Company proposes to revise LED streetlight pricing to reflect the total installed cost for each offering (Exhs. ES-RDC-1, at 67; ES-RDC-5, Sch. 3, at 1 (Rev. 3). The Company proposes to then apply a carrying charge to the LED installed cost, to derive the total revenue requirement, which is then divided by twelve to derive a monthly fixed charge (Exh. ES-RDC-1, at 67).

For Rate S-2, the Company proposes to develop a per-kWh charge to meet the target revenue requirement (Exhs. ES-RDC-1, at 66, ES-RDC-5, Sch. 2, at 6 (Rev. 3). Rate S-2 customers in the EMA service area have a customer charge and an energy charge; Rate S-2 customers in the WMA service area are billed based on lamp wattage (Exh. ES-RDC-1, at 68). For both the EMA and WMA service areas the Company proposes to implement a per-kWh energy rate calculated by dividing the class target revenue by the annual kWh sales for the rate class (Exh. ES-RDC-1, at 67-68). No party addressed these issues on brief.

b. Analysis and Findings

The Department has reviewed the Company's proposed changes for calculating streetlighting rates (Exhs. ES-RDC-1, at 65-68; ES-RDC-5 (Rev. 3)). The Department finds that the proposed rate design for both Company-owned and customer-owned streetlights is reasonable and meets our rate design goals and objectives, and therefore, are approved. In addition, the Department approves the revised LED streetlight pricing as proposed. Accordingly, the Department approves the rate design for streetlighting using the method proposed by the Company.

XVIII. TARIFF CHANGES

A. Terms and Conditions – Distribution Service

1. Introduction

The Company proposes four categories of changes to the appendices within its Terms and Conditions – Distribution Service tariff: (1) updates to the Schedule of Fees and Charges in Appendix A; (2) updates to the revenue multiplier in Appendix B used to credit customers for any contribution in aid of construction ("CIAC"); (3) the addition of "clarifying language" to the Appendix B sections that address line extension responsibilities; and (4) updates to the list of cities and towns in Appendix C (Exhs. ES-RDC-1, at 70; ES-RDC-6, Sch. 2, at 20, 25, 26, 34, 35, 39, 44, 46, 48, 50-52). No party addressed these proposed changes on brief.

2. Analysis and Findings

With respect to the Schedule of Fees and Charges in Appendix A, the Company proposes to maintain the Returned Check Fee of $11.00; increase its Account Restoration Charge for meters from $30.00 to $103.00; increase its Account Restoration Charge for poles from $101.00 to $123.00; increase its Account Restoration Charge for manholes from $161.00 to $181.00; increase its Warrant Fee from $98.00 to $240.00; and decrease its Sales Tax Abatement Fee from $52.00 to $32.00 (Exhs. ES-RDC-6, Sch. 2, at 20; ES-RDC-7, WPs 3 through 5 (Rev. 2)).

Fees for ancillary services such as processing returned checks are intended to reimburse a company for actual costs incurred in providing these services. See, e.g., D.P.U. 17-05, at 735; D.P.U. 95-118, at 84; Whitinsville Water Company, D.P.U. 89-67, at 4-5 (1989); D.P.U. 956, at 62. The Department has found that fees for these various services must be based on the costs associated with these functions that the company actually incurred. DPU 17-05, at 735; D.P.U. 08-35, at 58; D.P.U. 89-67, at 4; D.P.U. 956, at 62. While the Department has accepted gradual adjustments to fees, excessive increases in a single step may violate the Department's continuity goal. D.P.U. 17-05, at 735; D.T.E. 05-27, at 354-355.

The Department has reviewed NSTAR Electric's proposed changes to its Schedule of Fees and Charges and the supporting calculations and assumptions, and we find that the changes are reasonable and based on the costs associated with these functions that the Company incurs (Exhs. ES-RDC-6, Sch. 2, at 20; ES-RDC-7, WPs 3 through 5 (Rev. 2); DPU 11-21; DPU 31-12; Tr. 8, at 868-879). Further, the Department finds that the Company has correctly incorporated the additional revenues associated with the fee increases as a revenue credit in its proposed costs of service (Exhs. ES-REVREQ-1, at 50-51; ES-REVREQ-2, Schs. 1, 6 (Rev. 4); ES-REVREQ-3, WP 6 (Rev. 4)). We note, however, that the Company rounded, rather than truncated, the proposed fees and charges identified in Appendix A. To ensure that the proposed fees and charges do not collect more than the costs for providing the particular service, the Department directs the Company to truncate the amounts at whole dollars (Exh. DPU 31-12). Accordingly, the Company's approved Schedule of Fees and Charges are: Returned Check Fee of $10.00;[226] Account Restoration Charge for meters of $102.00; Account Restoration Charge for poles of $123.00; Account Restoration Charge for manholes of $180.00; Warrant Fee of $240.00; and Sales Tax Abatement Fee of $31.00 (Exhs. DPU 31-4 & Att.; ES-RDC-7, WPs 3 through 5 (Rev. 2)). The effect of the approved fees and charges on the Company's revenues are reflected in the Department's Schedule 9 below.

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[226] NSTAR Electric proposed to maintain the current Returned Check Fee of $11.00 based on the Company's proposed ten-year PBR term (Exh. DPU 31-4). The Company concedes, however, that the cost for this service is $10.00 (Exh. DPU 31-4). Moreover, the Department has rejected the Company's proposed ten-year PBR term (<u>see</u> Section IV.D.5.a above).

Next, the Company proposes to update the revenue multiplier in Appendix B used to credit customers for any CIAC (Exhs. ES-RDC-1, at 70; ES-RDC-6, Sch. 2, at 39, 48). NSTAR Electric's current line extension policy provides that if a developer makes a CIAC for a line extension located within a way that is accepted by the municipality as a public way, that developer shall be refunded an amount equal to 3.6 times the annual revenues estimated to be received by the Company associated with the line extension for the development, subject to a maximum refund that is no greater than the contribution itself (Exh. ES-RDC-6, Sch. 2 at 39, 48). The Company proposes to increase this revenue multiplier to 4.1 times the annual revenues that the Company estimates will be received from the line extension (Exhs. ES-RDC-6, Sch. 2 at 39, 48; ES-RDC-7, WP 6, (Rev. 2)). The Department has reviewed the Company's supporting calculations (Exhs. ES-RDC-6, Sch. 2, at 39, 48; ES-RDC-7, WP 6 (Rev. 2); DPU 11-21; Tr. 8, at 880). The Department directs the Company to recalculate the CIAC revenue multiplier using the revenue requirement components as determined in this Order and submit the calculations as part of its compliance filing.

NSTAR Electric also proposes to include in Appendix B language regarding certain responsibilities for costs that arise during maintenance, repair, or restoration work by the Company on customer property (Exhs. ES-RDC-1, at 70; ES-RDC-6, Sch. 2, at 25, 26, 34, 35, 44, 46). The Department has reviewed the proposed language and the supporting record, and we find the proposed language acceptable (Exhs. DPU 29-1; Tr. 8, at 885-894;

RR-AG-21 through RR-AG-24). As such, the Company may include this language in its Terms and Conditions – Distribution Service tariff.

Finally, NSTAR Electric proposes to update the list of cities and towns that the Company serves in its EMA and WMA service areas (Exhs. ES-RDC-1, at 70; ES-RDC-6, Sch. 2, at 50-52). The Department finds this proposal to be reasonable and appropriate and, therefore, we approve the proposed changes to Appendix C.

Based the considerations above, NSTAR Electric is directed to file a revised Terms and Conditions – Distribution Service tariff with its compliance filing, consistent with the findings above.

B. Other Tariff Provisions

The Company proposes changes to its other tariffs to reflect the proposals submitted in this case or to update current tariff language (see generally Exh. ES-RDC-6, Sch. 2). In the various sections of this Order, the Department has addressed Company proposals that implicate a number of the proposed tariff changes (e.g., PBR mechanism proposals, vegetation management proposals, storm fund proposals). The Department directs the Company to make all appropriate tariff changes consistent with the Department's findings in those sections. The Department has reviewed all remaining proposed tariff changes not specifically addressed elsewhere in this Order or not associated with an issue that is specifically addressed in this Order. We find these proposed changes to be reasonable, and, therefore, we approve the changes. The Company shall file revised tariffs, as appropriate, with its compliance filing.

XIX. SCHEDULES

A. Schedule 1 – Revenue Requirements and Calculation of Revenue Increase

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
COST OF SERVICE				
Total O&M Expense	461,098,686	1,264,605	(34,145,265)	428,218,026
Uncollectible O&M due to increase	619,920	27,280	(202,161)	445,039
Depreciation & Amortization	252,847,877	(7,740,625)	(27,087,735)	218,019,517
Taxes Other Than Income Taxes	147,739,020	12,868,998	(5,919,880)	154,688,138
Income Taxes	92,636,063	(4,567,460)	(8,987,989)	79,080,614
Return on Rate Base	311,997,775	(7,753,952)	(26,938,141)	277,305,682
Total Cost of Service	1,266,939,341	(5,901,154)	(103,281,171)	1,157,757,016
OPERATING REVENUES				
Total Distribution Revenues	1,146,568,761	(11,390,573)	(74,004,799)	1,061,173,390
Other Revenues	30,892,717	1,523,794	(88,188)	32,328,323
Total Operating Revenues	1,177,461,478	(9,866,779)	(74,092,987)	1,093,501,713
Total Revenue Deficiency	**89,477,863**	**3,965,625**	**(29,188,185)**	**64,255,303** *

* The Total Revenue Deficiency is adjusted for AMR/legacy CIS & MDMS, Vegetation Management, and SMART Program that are currently recovered or were proposed to be recovered in base rates and will be transferred or remain for recovery through reconciling mechanisms pursuant to the directives in this proceeding.

Numbers may not add due to rounding. Minor discrepancies between these numbers and those in the text are due to rounding.

B. Schedule 2 – Operations and Maintenance Expenses

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
Test Year O&M Expense	410,768,033	(2,150,638)	0	408,617,395
ADJUSTMENTS TO O&M EXPENSE:				
Compensation: Payroll Expense	13,138,206	105	0	13,138,311
Compensation: Variable Compensation	(6,821,176)	0	(3,232,371)	(10,053,547)
Dues and Memberships	0	0	(363,166)	(363,166)
Employee Benefits Costs	7,164,314	955,023	0	8,119,337
Enterprise IT Projects Expense (includes AMI and SMART)	10,869,443	(2,963,414)	(3,657,238)	4,248,791
Insurance Expense And Injuries & Damages	1,462,386	709,186	(500,410)	1,671,162
Work Asset Management Training	0	0	(2,777,920)	(2,777,920)
Postage Expense	100,368	0	0	100,368
Lease Expense	942,762	(303,318)	0	639,444
Regulatory Assessments	0	(1,182,653)	0	(1,182,653)
Rate Case Expense	763,234	(141,596)	0	621,638
Uncollectible Expense	(1,166,264)	(4,238)	0	(1,170,502)
Resiliency Tree Work Program	0	0	(23,200,000)	(23,200,000)
Storm Fund Adjustment	21,000,000	0	0	21,000,000
Storm Cost Adjustment	(4,200,000)	0	0	(4,200,000)
Residual O&M Inflation Adjustment	7,077,380	6,346,148	(414,160)	13,009,368
Total Adjustment to O&M Expense	50,330,653	3,415,243	(34,145,265)	19,600,631
Total O&M Expense	**461,098,686**	**1,264,605**	**(34,145,265)**	**428,218,026**

Numbers may not add due to rounding. Minor discrepancies between these numbers and those in the text are due to rounding.

C. Schedule 2A – Inflation Table

Test Year O&M Expense	$ 408,617,395
	$ 408,617,395
Less: Company Adjustments	
Compensation: Payroll Expense	$ 144,958,863
Compensation: Variable Compensation	$ 16,503,810
Dues and Memberships	$ 802,347
Employee Benefits Costs	$ 15,617,670
Enterprise IT Projects Expense	$ 33,020,432
Insurance Expense and Injuries & Damages	$ 4,035,454
Postage Expense	$ 4,338,141
Lease Expense	$ 7,010,708
Regulatory Assessments	$ 11,804,920
Uncollectibles Expense	$ 15,281,020
Vegetation Management Expense[227]	$ 43,207,619
Storm Fund Adjustment	$ 10,000,000
Storm Cost Adjustment	$ 12,000,000
Total Company O&M Adjustments	$ 318,580,984
Residual O&M Expense Subject to Inflation per Company	$ 90,036,411
Inflation Factor	14.909%
Inflation Allowance per Company	$ 13,423,528
Less: Department Adjustments	
Work Asset Management Training	$ 2,777,920
Department Sub-total	$ 2,777,920
Residual O&M Expense Subject to Inflation per DPU	$ 87,258,491
Inflation Factor	14.909%
Inflation Allowance per DPU	$ 13,009,368

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[227] The Department transferred $23,200,000 from the Company’s test year Vegetation Management expense to a reconciling mechanism in Section XI.C.4.b above. That transfer, however, is not reflected here because it would necessitate a corresponding adjustment to the test year O&M expense of $408,617,395, and thus, would result in no change to the approved inflation allowance.

D. Schedule 3 – Depreciation and Amortization Expenses

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
Depreciation and Amortization Expense	231,820,683	(7,126,708)	(27,087,735)	197,606,240
Amortization of Deferred Assets	21,027,194	(613,917)	0	20,413,277
Total Depreciation and Amortization Expense	**252,847,877**	**(7,740,625)**	**(27,087,735)**	**218,019,517**

Numbers may not add due to rounding. Minor discrepancies between these numbers and those in the text are due to rounding.

E. Schedule 4 – Rate Base and Return on Rate Base

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
Utility Plant in Service	8,158,167,577	(257,233,638)	(328,863,241)	7,572,070,698
LESS:				
Reserve for Depreciation	2,611,720,164	(62,449,509)	(120,017,193)	2,429,253,462
Reserve for Amortization	49,613,183	(2,196,844)	0	47,416,339
Net Utility Plant in Service	5,496,834,230	(192,587,285)	(208,846,048)	5,095,400,897
ADDITIONS TO PLANT:				
Cash Working Capital	53,688,003	1,276,279	(3,616,840)	51,347,443
Materials and Supplies	52,956,389	4,165,283	0	57,121,672
Total Additions to Plant	106,644,392	5,441,562	(3,616,840)	108,469,115
DEDUCTIONS FROM PLANT:				
Reserve for Deferred Income Tax	733,301,500	11,030,397	(47,343,789)	696,988,108
FAS 109 Regulatory Liability (net)	560,994,216	(28,674,651)	0	532,319,565
Customer Deposits	5,032,962	(789,353)	0	4,243,609
Customer Advances	40,487,331	(237,788)	0	40,249,543
Total Deductions from Plant	1,339,816,009	(18,671,395)	(47,343,789)	1,273,800,825
RATE BASE	4,263,662,613	(168,474,328)	(165,119,099)	3,930,069,187
COST OF CAPITAL	7.32%	0.11%	-0.37%	7.06%
RETURN ON RATE BASE	**311,997,775**	**(7,753,952)**	**(26,938,141)**	**277,305,682**

Numbers may not add due to rounding. Minor discrepancies between these numbers and those in the text are due to rounding.

F. Schedule 5 – Cost of Capital

PER COMPANY

	PRINCIPAL	PERCENTAGE	COST	RATE OF RETURN
Long-Term Debt	$4,020,000,000	45.71%	3.60%	1.65%
Preferred Stock	$43,000,000	0.49%	4.56%	0.02%
Common Equity	$4,731,109,220	53.80%	10.50%	5.65%
Total Capital	$8,794,109,220	100.00%		7.32%
Weighted Cost of				
Debt				1.65%
Preferred				0.02%
Equity				5.65%
Cost of Capital				7.32%

ADJUSTED PER COMPANY

	PRINCIPAL	PERCENTAGE	COST	RATE OF RETURN
Long-Term Debt	$4,470,000,000	46.34%	3.93%	1.82%
Preferred Stock	$43,000,000	0.45%	4.56%	0.02%
Common Equity	$5,133,109,220	53.21%	10.50%	5.59%
Total Capital	$9,646,109,220	100.00%		7.43%
Weighted Cost of				
Debt				1.82%
Preferred				0.02%
Equity				5.59%
Cost of Capital				7.43%

PER ORDER

	PRINCIPAL	PERCENTAGE	COST	RETURN
Long-Term Debt	$4,470,000,000	46.34%	3.93%	1.82%
Preferred Stock	$43,000,000	0.45%	4.56%	0.02%
Common Equity	$5,133,109,220	53.21%	9.80%	5.22%
Total Capital	$9,646,109,220	100.00%		7.06%
Weighted Cost of				
Debt				1.82%
Preferred				0.02%
Equity				5.22%
Cost of Capital				**7.06%**

Numbers may not add due to rounding. Minor discrepancies between these numbers and those in the text are due to rounding.

G. Schedule 6 – Cash Working Capital

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
Electric O&M Expenses	461,098,686	1,264,605	(34,145,265)	428,218,026
Less Uncollectible Accounts	14,114,756	(4,238)	0	14,110,518
Taxes Other Than Income	147,739,020	12,868,998	(5,919,880)	154,688,138
Total Costs Applicable to Cash Working Capital	**594,722,950**	**14,137,841**	**(40,065,145)**	**568,795,646**
Cash Working Capital Factor (32.95 Days/365)	9.03%	9.03%	9.03%	9.03%
Cash Working Capital Adjustment	**53,688,003**	**1,276,279**	**(3,616,840)**	**51,347,443**

Numbers may not add due to rounding. Minor discrepancies between these numbers and those in the text are due to rounding.

H. Schedule 7 – Taxes Other Than Income Taxes

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
Property Taxes	134,635,202	12,868,998	(5,919,880)	141,584,320
FICA	9,519,756	0	0	9,519,756
Medicare	2,893,609	0	0	2,893,609
Federal Unemployment	33,112	0	0	33,112
State Unemployment	281,813	0	0	281,813
State Insurance Premium Excise Tax	86,154	0	0	86,154
Universal Health (MA)	34,708	0	0	34,708
State Sales and Use Tax	253,980	0	0	253,980
Paid Family Medical Leave	686	0	0	686
Total Taxes Other Than Income Taxes	**147,739,020**	**12,868,998**	**(5,919,880)**	**154,688,138**

Numbers may not add due to rounding. Minor discrepancies between these numbers and those in the text are due to rounding.

I. Schedule 8 – Income Taxes

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
Rate Base	4,263,662,613	(168,474,328)	(165,119,099)	3,930,069,187
Return on Rate Base	311,997,775	(7,753,952)	(26,938,141)	277,305,682
ADJUSTMENTS				
Flow Through and Permanent Items	4,100,992	0	0	4,100,992
FAS 109 Income Taxes and ITC	147,235	0	0	147,235
Interest Expense	(70,196,941)	(4,396,914)	3,027,295	(71,566,560)
Excess ADIT Amortization	0	0	0	0
Total Deductions	(65,948,714)	(4,396,914)	3,027,295	(67,318,333)
Taxable Income Base	246,049,061	(12,150,866)	(23,910,847)	209,987,349
Gross Up Factor	1.3759	1.3759	1.3759	1.3759
Taxable Income	338,538,904	(16,718,376)	(32,898,934)	288,921,593
Mass Income Tax (8%)	27,083,112	(1,337,470)	(2,631,915)	23,113,727
Federal Taxable Income	311,455,792	(15,380,906)	(30,267,019)	265,807,866
Federal Income Tax (21%)	65,405,716	(3,229,990)	(6,356,074)	55,819,652
Total Income Taxes Calculated	92,488,828	(4,567,460)	(8,987,989)	78,933,379
FAS 109 Income Taxes and ITC	147,235	0	0	147,235
Less: Excess ADIT Amortization	0	0	0	0
Total Income Taxes	**92,636,063**	**(4,567,460)**	**(8,987,989)**	**79,080,614**

Numbers may not add due to rounding. Minor discrepancies between these numbers and those in the text are due to rounding.

J. Schedule 9 – Revenues

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
Distribution Revenue *	973,557,967	0	(48,911,081)	924,646,886
Revenue Decoupling - (Prior Year Billed)	13,545,230	0	0	13,545,230
Revenue Decoupling - Accrual	34,496,381	0	0	34,496,381
Resiliency Tree Work Pilot- RTW	23,200,000	0	(23,200,000)	0
Solar Expansion Revenue	21,700,536	0	0	21,700,536
Solar Program WMA Revenue	33,394	(33,394)	0	(0)
MA Smart Solar Revenue	1,893,718	0	(1,893,718)	0
Grid Mod Tracked Revenue	11,357,179	(11,357,179)	0	0
Additional PBR Revenue	66,784,356	0	0	66,784,356
Total Distribution Revenue	1,146,568,761	(11,390,573)	(74,004,799)	1,061,173,390
Other Revenues				
Sales for Resale	43,330	0	0	43,330
Provision for Rate Refunds	0	0	0	0
Forfeited Accounts	704,134			704,134
Misc. Service Revenues	5,046,344	43,916	(88,188)	5,002,072
Rent from Electric Property	15,197,523	1,479,878	0	16,677,401
Other Electric Revenue	9,901,386	0	0	9,901,386
Revenues from Transmission of Electricity of Others	0	0	0	0
Total Other Revenues	30,892,717	1,523,794	(88,188)	32,328,323
Adjusted Total Operating Revenues	**1,177,461,478**	**(9,866,779)**	**(74,092,987)**	**1,093,501,713**

* The DPU Adjustment is to remove revenue to be collected through the new AMI factor.

Numbers may not add due to rounding. Minor discrepancies between these numbers and those in the text are due to rounding.

K. Schedule 10 – Allocation to Rate Groups and Rate Classes

Schedule 10 – Group – For illustrative purposes only

Rate Group	Total Revenue at Current Rates	Base Distribution Revenue at Current Rates*	Base Rate Transfers	Base Distribution Revenue at EROR	Change in Reconciling Revenue	Base Distribution Revenue Increase at EROR
	(a)	(b)	(c)	(d)	(e)	(f)
Residential	$2,082,953,605	$519,018,176	-$13,403,878	$574,063,620	$35,189,655	$55,045,444
Small General Service	$965,130,376	$223,538,825	-$5,772,991	$217,025,171	$9,717,048	-$6,513,655
Medium General Service	$1,007,330,174	$194,675,611	-$5,027,585	$193,655,596	-$2,844,217	-$1,020,015
Large General Service	$823,018,000	$105,805,745	-$2,732,481	$125,912,174	$3,654,648	$20,106,429
Lighting - Company	$15,029,424	$8,115,357	-$209,583	$10,393,544	$28,617	$2,278,187
Lighting - Customer	$11,316,117	$2,143,829	-$55,365	$2,701,846	-$42,848	$558,017
Total Company	$4,904,777,696	$1,053,297,543	-$27,201,883	$1,123,751,951	$45,702,903	$70,454,408

* The Total Company Base Distribution Revenue at Current Rates shown in column (b) differs from the Total Distribution Revenues shown on Schedule 1 because the total shown above in column (b) was calculated using rates in effect January 1, 2022 and 2021 calendar year billing quantities, while the total distribution revenues shown on Schedule 1 was determined by taking normalized test year distribution revenues and adjusting them for the additional PBR revenues, transfers from reconciling items, and revenue decoupling. The difference in the distribution revenues between the two schedules also results in a difference in the revenue deficiency between these two schedules.

TOTAL REVENUE CAP						
	ITERATION 1					
Rate Group	**10% Total Revenue Cap**	**Total Revenue Increase Greater Than 10%**	**Base Distribution Revenue Allocator**	**Allocation of Revenues Greater Than 10%**	**Total Revenue Increase After Reallocation**	**Total Revenue Increase Greater Than 10%**
	(g)	(h)	(i)	(j)	(k)	(l)
Residential	$208,295,360	$0	$574,063,620	$414,483	$90,649,582	$0
Small General Service	$96,513,038	$0	$217,025,171	$156,695	$3,360,089	$0
Medium General Service	$100,733,017	$0	$193,655,596	$139,822	-$3,724,409	$0
Large General Service	$82,301,800	$0	$125,912,174	$90,910	$23,851,988	$0
Lighting - Company	$1,502,942	$803,861	$0	$0	$1,502,942	$0
Lighting - Customer	$1,131,612	$0	$2,701,846	$1,951	$517,120	$0
Total Company	$490,477,770	$803,861	$1,113,358,407	$803,861	$116,157,311	$0

Schedule 10 – Group continued – For illustrative purposes only

BASE DISTRIBUTION REVENUE CAP						
	ITERATION 1					
Rate Group	**200% Base Distribution Revenue Increase Cap**	**Base Distribution Revenue Increase Greater Than 200%**	**Base Distribution Revenue Allocator**	**Allocation of Base Distribution Revenues Greater Than 200%**	**Base Distribution Revenue Increase After Reallocation**	**Base Distribution Revenue Increase Greater Than 200%**
	(m)	(n)	(o)	(p)	(q)	(r)
Residential	$69,433,597	$0	$574,063,620	$3,908,501	$59,368,428	$0
Small General Service	$29,904,742	$0	$217,025,171	$1,477,612	-$4,879,347	$0
Medium General Service	$26,043,458	$0	$193,655,596	$1,318,500	$438,308	$0
Large General Service	$14,154,559	$6,042,780	$0	$0	$14,154,559	$0
Lighting - Company	$1,085,662	$388,664	$0	$0	$1,085,662	$0
Lighting - Customer	$286,799	$273,169	$0	$0	$286,799	$0
Total Company	$140,908,816	$6,704,613	$984,744,387	$6,704,613	$70,454,408	$0

BASE DISTRIBUTION REVENUE FLOOR					
	ITERATION 1				
Rate Group	**Base Distribution Revenue Decrease**	**Base Distribution Revenue Allocator**	**Allocation of Base Distribution Revenue Decrease**	**Base Distribution Revenue After Reallocation**	**Base Distribution Revenue Decrease**
	(s)	(t)	(u)	(v)	(w)
Residential	$0	$574,063,620	$3,089,195	$56,279,233	$0
Small General Service	$4,879,347	$0	$0	$0	$0
Medium General Service	$0	$193,655,596	$1,042,114	-$603,807	$603,807
Large General Service	$0	$125,912,174	$677,568	$13,476,991	$0
Lighting - Company	$0	$10,393,544	$55,931	$1,029,732	$0
Lighting - Customer	$0	$2,701,846	$14,539	$272,259	$0
Total Company	$4,879,347	$906,726,780	$4,879,347	$70,454,408	$603,807

Schedule 10 – Group continued – For illustrative purposes only

	ITERATION 2			
Rate Group	**Base Distribution Revenue Allocator**	**Allocation of Base Distribution Revenue Decrease**	**Base Distribution Revenue After Reallocation**	**Base Distribution Revenue Decrease**
	(x)	(y)	(z)	(aa)
Residential	$574,063,620	$486,099	$55,793,134	$0
Small General Service	$0	$0	$0	$0
Medium General Service	$0	$0	$0	$0
Large General Service	$125,912,174	$106,619	$13,370,372	$0
Lighting - Company	$10,393,544	$8,801	$1,020,931	$0
Lighting - Customer	$2,701,846	$2,288	$269,971	$0
Total Company	$713,071,184	$603,807	$70,454,408	$0

Rate Group	**Final Base Distribution Revenue Increase**	**Rate Group Base Distribution Revenue Target**	**Total Revenue Increase**	**Rate Group Total Revenue Target**
	(ab)	(ac)	(ad)	(ae)
Residential	$55,793,134	$574,811,310	$90,982,789	$2,173,936,393
Small General Service	$0	$223,538,825	$9,717,048	$974,847,424
Medium General Service	$0	$194,675,611	-$2,844,217	$1,004,485,957
Large General Service	$13,370,372	$119,176,117	$17,025,020	$840,043,021
Lighting - Company	$1,020,931	$9,136,287	$1,049,547	$16,078,972
Lighting - Customer	$269,971	$2,413,800	$227,124	$11,543,240
Total Company	$70,454,408	$1,123,751,951	$116,157,311	$5,020,935,007

Rate Group	**Percent Increase in Distribution Revenue**	**Percent Increase in Total Revenue**	**Unit Distribution Demand Cost at EROR (per kWh or kW)**
	(af)	(ag)	(ah)
Residential	10.75	4.37	$0.07051
Small General Service	-	1.01	$0.04961
Medium General Service	-	(0.28)	$15.10
Large General Service	12.64	2.07	$11.27
Lighting - Company	12.58	6.98	$0.17967
Lighting - Customer	12.59	2.01	$0.67188
Total Company	6.69	2.37	

Column definitions:
(a): Exh. ES-RDC-2, Sch 5, (Rev. 3)
(b): Exh. ES-RDC-2, Sch 5, (Rev. 3)
(c): Exh. ES-RDC-2, Sch 4, (Rev. 3) adjusted for allowed transfers and RAAF adjustment per low-income discount increase
(d): Exh. ES-ACOS-2, (Rev. 3) adjusted per Order
(e): Exh. ES-RDC-2, Sch 5 (Rev. 3) adjusted for allowed transfers and RAAF adjustment per low-income discount increase
(f): (d) – (b)
Total Revenue Cap:
(g): 10% of (a)
(h): if (e) + (f) > (g), then (e) + (f); else 0
(i): if (h) = 0, (d); else 0
(j): [total (h)] * {(i) / [total (i)]}
(k): (e) + (f) - (h) + (j)
(l): if (k) > (g), then (k) - (g); else 0
Base Distribution Revenue Cap:
(m): 200% of (b) * {[total (k)] – [total (e)]} / [total (b)]
(n): if [(k) - (e)] > (m), then [(k) - (e)] – (m); else 0
(o): if (n) = 0, then (d); else 0
(p): if (o) > 0, then [total (n)]*{p / [total (p)]}; else 0
(q): (k) – (e) - (n) + (p)
(r): if [(q) > m], then [(q) – (m)]; else 0
Base Distribution Revenue Floor:
(s): if (q) > 0, then 0; else -(q)
(t): if (s) = 0, then (d); else 0
(u): if (t) > 0, then [total (s)] * (t) / [(total (t)]
(v): (q) + (s) – (u)
(w): if (v) > 0, then 0; else -(v)
(x): if (w) = 0 AND (s) = 0, then (d); else 0
(y): if (x) > 0, then [total (w)] * (x) / [(total (x)]
(z): (v) + (w) – (y)
(aa): if (z) < 0, (z); else 0
Per Order:
(ab): (z)
(ac): (b) + (z)
(ad): (e) + (ab)
(ae): (a) + (ad)
(af): [(ab) / (b)] * 100
(ag): [(ad) / (a)] * 100
(ah): (ac) / test year kWh (residential, small C&I, streetlighting) or kW (medium C&I and large C&I)

Schedule 10 – Residential – For illustrative purposes only

Rate Class	Total Revenue at Current Rates	Base Distribution Revenue at Current Rates	Base Rate Transfers	Unit Distribution Demand Cost at EROR (per kWh)
R-1/R-2 Residential	$1,860,455,924	$468,373,502	$(12,099,808)	$0.07051
R-3/R-4 Residential Heating	$222,497,681	$50,644,673	$(1,308,338)	$0.07051
Total Residential	$2,082,953,605	$519,018,176	$(13,408,146)	

Rate Class	Base Distribution Revenue at Group Unit Cost	Change in Reconciling Revenue	Base Distribution Revenue Increase at Group Unit Cost
R-1/R-2 Residential	$1,860,455,924	$27,470,018	$40,277,922
R-3/R-4 Residential Heating	$222,497,681	$7,719,637	$15,515,257
Total Residential	$1,860,455,924	$35,189,655	$55,793,179

TOTAL REVENUE CAP						
	ITERATION 1					
Rate Class	**10% Total Revenue Cap**	**Total Revenue Increase Greater Than 10%**	**Base Distribution Revenue Allocator**	**Allocation of Revenues Greater Than 10%**	**Total Revenue Increase After Reallocation**	**Total Revenue Increase Greater Than 10%**
R-1/R-2 Residential	$186,045,592	$-	$508,651,424	$985,127	$68,733,066	$0
R-3/R-4 Residential Heating	$22,249,768	$985,127	$-	$-	$22,249,768	$0
Total Residential	$208,295,360	$985,127	$508,651,424	$985,127	$90,982,834	$0

BASE DISTRIBUTION REVENUE CAP						
	ITERATION 1					
Rate Class	**200% Base Distribution Revenue Increase Cap**	**Base Distribution Revenue Increase Greater Than 200%**	**Base Distribution Revenue Allocator**	**Allocation of Base Distribution Revenues Greater Than 200%**	**Base Distribution Revenue Increase After Reallocation**	**Base Distribution Revenue Increase Greater Than 200%**
R-1/R-2 Residential	$62,658,470	$-	$508,651,424	$7,754,944	$49,017,993	$-
R-3/R-4 Residential Heating	$6,775,186	$7,754,944	$-	$-	$6,775,186	$-
Total Residential		$7,754,944	$508,651,424	$7,754,944	$55,793,179	$-

BASE DISTRIBUTION REVENUE FLOOR					
Rate Group	**Base Distribution Revenue Decrease**	**Final Base Distribution Revenue Increase**	**Rate Group Base Distribution Revenue Target**	**Total Revenue Increase**	**Rate Group Total Revenue Target**
R-1/R-2 Residential	$-	$49,017,993	$517,391,495	$76,488,010	$1,936,943,934
R-3/R-4 Residential Heating	$-	$6,775,186	$57,419,860	$14,494,824	$236,992,505
Total Residential	$-	$55,793,179	$574,811,355	$90,982,834	$2,173,936,439

Rate Group	Percent Increase in Distribution Revenue	Percent Increase in Total Revenue
R-1/R-2 Residential	10.47	4.11
R-3/R-4 Residential Heating	13.38	6.51
Total Residential	10.75	4.37

Schedule 10 – Small C&I – For illustrative purposes only

Rate Class	Total Revenue at Current Rates	Base Distribution Revenue at Current Rates	Base Rate Transfers	Unit Distribution Demand Cost at EROR (per kWh)
G-1/T-1 (<=100 kW) (Boston Edison)	$597,554,938	$145,618,566	$(3,761,863)	$0.04961
G-1/G-6 (<=100 kW) (Cambridge Electric Light)	$45,370,801	$8,374,859	$(216,353)	$0.04961
G-5 Comm. Space Heat (Cambridge Electric Light)	$864,930	$118,103	$(3,051)	$0.04961
G-1 Gen. Serv. (Commonwealth Electric)	$189,569,184	$38,532,022	$(995,424)	$0.04961
G-7 Optional TOU (Commonwealth Electric)	$12,137,989	$2,119,466	$(54,754)	$0.04961
G-4 General Power (Commonwealth Electric)	$453,460	$83,949	$(2,169)	$0.04961
G-5 Comm. Space Heat (Commonwealth Electric)	$1,976,099	$411,198	$(10,623)	$0.04961
G-6 All Electric School (Commonwealth Electric)	$861,601	$94,725	$(2,447)	$0.04961
23 Optional Water Heating (WMA)	$12,952	$5,247	$(136)	$0.04961
24 Optional Church (WMA)	$1,004,634	$303,975	$(7,853)	$0.04961
G-1 (<=100 kW) (WMA)	$115,323,788	$27,876,714	$(720,158)	$0.04961
Total Small C&I	$965,130,376	$223,538,825	$(5,774,829)	

Rate Class	Base Distribution Revenue at Group Unit Cost	Change in Reconciling Revenue	Base Distribution Revenue Increase at Group Unit Cost
G-1/T-1 (<=100 kW) (Boston Edison)	$133,224,258	$3,058,335	$(12,394,308)
G-1/G-6 (<=100 kW) (Cambridge Electric Light)	$11,513,911	$1,326,544	$3,139,051
G-5 Comm. Space Heat (Cambridge Electric Light)	$229,098	$23,567	$110,995
G-1 Gen. Serv. (Commonwealth Electric)	$45,429,184	$3,235,565	$6,897,161
G-7 Optional TOU (Commonwealth Electric)	$3,161,495	$225,169	$1,042,029
G-4 General Power (Commonwealth Electric)	$118,265	$13,716	$34,317
G-5 Comm. Space Heat (Commonwealth Electric)	$447,650	($27,494)	$36,452
G-6 All Electric School (Commonwealth Electric)	$245,741	$59,460	$151,016
23 Optional Water Heating (WMA)	$2,605	$115	$(2,642)
24 Optional Church (WMA)	$234,306	$10,312	$(69,670)
G-1 (<=100 kW) (WMA)	$28,932,312	$1,791,760	$1,055,598
Total Small C&I	$223,538,825	$9,717,048	$0

TOTAL REVENUE CAP						
	ITERATION 1					
Rate Class	**10% Total Revenue Cap**	**Total Revenue Increase Greater Than 10%**	**Base Distribution Revenue Allocator**	**Allocation of Revenues Greater Than 10%**	**Total Revenue Increase After Reallocation**	**Total Revenue Increase Greater Than 10%**
G-1/T-1 (<=100 kW) (Boston Edison)	$59,755,494	$-	$133,224,258	$138,489	$(9,197,484)	$-
G-1/G-6 (<=100 kW) (Cambridge Electric Light)	$4,537,080	$-	$11,513,911	$11,969	$4,477,564	$-
G-5 Comm. Space Heat (Cambridge Electric Light)	$86,493	$48,070	$-	$-	$86,493	$-
G-1 Gen. Serv. (Commonwealth Electric)	$18,956,918	$-	$45,429,184	$47,225	$10,179,951	$-
G-7 Optional TOU (Commonwealth Electric)	$1,213,799	$53,398	$-	$-	$1,213,799	$-
G-4 General Power (Commonwealth Electric)	$45,346	$2,686	$-	$-	$45,346	$-
G-5 Comm. Space Heat (Commonwealth Electric)	$197,610	$-	$447,650	$465	$9,424	$-

G-6 All Electric School (Commonwealth Electric)	$86,160	$124,316	$-	$-	$86,160	$-
23 Optional Water Heating (WMA)	$1,295	$-	$2,605	$3	$(2,525)	$-
24 Optional Church (WMA)	$100,463	$-	$234,306	$244	$(59,114)	$-
G-1 (< =100 kW) (WMA)	$11,532,379	$-	$28,932,312	$30,076	$2,877,434	$-
Total Small C&I	$96,513,038	$228,470	$219,784,225	$228,470	$9,717,048	$-
BASE DISTRIBUTION REVENUE CAP						
	ITERATION 1					
Rate Class	**200% Base Distribution Revenue Increase Cap**	**Base Distribution Revenue Increase Greater Than 200%**	**Base Distribution Revenue Allocator**	**Allocation of Base Distribution Revenues Greater Than 200%**	**Base Distribution Revenue Increase After Reallocation**	**Base Distribution Revenue Increase Greater Than 200%**
G-1/T-1 (< =100 kW) (Boston Edison)	$19,480,685	$-	$133,224,258	$3,769,018	$(8,486,801)	$-
G-1/G-6 (< =100 kW) (Cambridge Electric Light)	$1,120,379	$2,030,641	$-	$-	$1,120,379	$-
G-5 Comm. Space Heat (Cambridge Electric Light)	$15,800	$47,126	$-	$-	$15,800	$-
G-1 Gen. Serv. (Commonwealth Electric)	$5,154,770	$1,789,616	$-	$-	$5,154,770	$-
G-7 Optional TOU (Commonwealth Electric)	$283,540	$705,091	$-	$-	$283,540	$-
G-4 General Power (Commonwealth Electric)	$11,231	$20,400	$-	$-	$11,231	$-
G-5 Comm. Space Heat (Commonwealth Electric)	$55,010	$-	$447,650	$12,664	$49,582	$-
G-6 All Electric School (Commonwealth Electric)	$12,672	$14,028	$-	$-	$12,672	$-
23 Optional Water Heating (WMA)	$702	$-	$2,605	$74	$(2,566)	$-
24 Optional Church (WMA)	$40,665	$-	$234,306	$6,629	$(62,797)	$-
G-1 (< =100 kW) (WMA)	$3,729,315	$-	$28,932,312	$818,518	$1,904,192	$-
Total Small C&I	$29,904,767	$4,606,902	$162,841,131	$4,606,902	$0	$-

BASE DISTRIBUTION REVENUE FLOOR		
Rate Group	**Base Distribution Revenue Decrease**	Since there is no change to the current distribution revenue for the entire group, revenue floor iterations would continue until each rate class received no change in base distribution revenues.
G-1/T-1 (<=100 kW) (Boston Edison)	$-	
G-1/G-6 (<=100 kW) (Cambridge Electric Light)	$-	
G-5 Comm. Space Heat (Cambridge Electric Light)	$-	
G-1 Gen. Serv. (Commonwealth Electric)	$-	
G-7 Optional TOU (Commonwealth Electric)	$-	
G-4 General Power (Commonwealth Electric)	$-	
G-5 Comm. Space Heat (Commonwealth Electric)	$-	
G-6 All Electric School (Commonwealth Electric)	$(43,619)	
23 Optional Water Heating (WMA)	$-	
24 Optional Church (WMA)	$-	
G-1 (<=100 kW) (WMA)	$-	
Total Small C&I	$(43,619)	

Rate Group	Final Base Distribution Revenue Increase	Rate Group Base Distribution Revenue Target	Total Revenue Increase	Rate Group Total Revenue Target	Percent Increase in Distribution Revenue	Percent Increase in Total Revenue
G-1/T-1 (<=100 kW) (Boston Edison)	$-	$145,618,566	$3,058,335	$600,613,273	-	0.51
G-1/G-6 (<=100 kW) (Cambridge Electric Light)	$-	$8,374,859	$1,326,544	$46,697,344	-	2.92
G-5 Comm. Space Heat (Cambridge Electric Light)	$-	$118,103	$23,567	$888,498	-	2.72
G-1 Gen. Serv. (Commonwealth Electric)	$-	$38,532,022	$3,235,565	$192,804,749	-	1.71
G-7 Optional TOU (Commonwealth Electric)	$-	$2,119,466	$225,169	$12,363,158	-	1.86
G-4 General Power (Commonwealth Electric)	$-	$83,949	$13,716	$467,176	-	3.02
G-5 Comm. Space Heat (Commonwealth Electric)	$-	$411,198	$(27,494)	$1,948,605	-	(1.39)
G-6 All Electric School (Commonwealth Electric)	$-	$94,725	$59,460	$921,061	-	6.90
23 Optional Water Heating (WMA)	$-	$5,247	$115	$13,066	-	0.89

24 Optional Church (WMA)	$-	$303,975	$10,312	$1,014,945	-	1.03
G-1 (< =100 kW) (WMA)	$-	$27,876,714	$1,791,760	$117,115,549	-	1.55
Total Small C&I	$-	$223,538,825	$9,717,048	$974,847,424	-	1.01

Schedule 10 – Medium C&I – For illustrative purposes only

Rate Class	Total Revenue at Current Rates	Base Distribution Revenue at Current Rates	Base Rate Transfers	Unit Distribution Demand Cost at EROR (per kW)
G-2 TOU (Boston Edison)	$773,206,844	$160,011,887	$(4,133,695)	$15.10
G-2 TOU (Cambridge Electric Light)	$99,209,689	$13,658,395	$(352,847)	$15.10
G-2 TOU (Commonwealth Electric)	$72,882,017	$10,357,394	$(267,570)	$15.10
G-2/T4 (WMA)	$62,031,623	$10,647,936	$(275,075)	$15.10
Total Medium C&I	$1,007,330,174	$194,675,611	$(5,029,186)	

Rate Class	Base Distribution Revenue at Group Unit Cost	Change in Reconciling Revenue	Base Distribution Revenue Increase at Group Unit Cost
G-2 TOU (Boston Edison)	$142,147,912	($7,471,813)	$(17,863,975)
G-2 TOU (Cambridge Electric Light)	$20,131,914	$2,745,488	$6,473,519
G-2 TOU (Commonwealth Electric)	$17,171,062	$1,669,464	$6,813,668
G-2/T4 (WMA)	$15,224,724	$212,644	$4,576,788
Total Medium C&I	$194,675,611	$(2,844,217)	$0

TOTAL REVENUE CAP						
	ITERATION 1					
Rate Class	**10% Total Revenue Cap**	**Total Revenue Increase Greater Than 10%**	**Base Distribution Revenue Allocator**	**Allocation of Revenues Greater Than 10%**	**Total Revenue Increase After Reallocation**	**Total Revenue Increase Greater Than 10%**
G-2 TOU (Boston Edison)	$77,320,684	$-	$142,147,912	$956,916	$(24,378,872)	$-
G-2 TOU (Cambridge Electric Light)	$9,920,969	$-	$20,131,914	$135,525	$9,354,532	$-
G-2 TOU (Commonwealth Electric)	$7,288,202	$1,194,931	$-	$-	$7,288,202	$-
G-2/T4 (WMA)	$6,203,162	$-	$15,224,724	$102,490	$4,891,922	$-

Total Medium C&I	$100,733,017	$1,194,931	$177,504,550	$1,194,931	$(2,844,217)	$-

BASE DISTRIBUTION REVENUE CAP						
	ITERATION 1					
Rate Class	**200% Base Distribution Revenue Increase Cap**	**Base Distribution Revenue Increase Greater Than 200%**	**Base Distribution Revenue Allocator**	**Allocation of Base Distribution Revenues Greater Than 200%**	**Base Distribution Revenue Increase After Reallocation**	**Base Distribution Revenue Increase Greater Than 200%**
G-2 TOU (Boston Edison)	$21,406,207	$-	$142,147,912	$12,269,786	$(4,637,273)	$-
G-2 TOU (Cambridge Electric Light)	$1,827,204	$4,781,840	$-	$-	$1,827,204	$-
G-2 TOU (Commonwealth Electric)	$1,385,600	$4,233,137	$-	$-	$1,385,600	$-
G-2/T4 (WMA)	$1,424,469	$3,254,810	$-	$-	$1,424,469	$-
Total Medium C&I	$26,043,480	$12,269,786	$142,147,912	$12,269,786	$0	$-

BASE DISTRIBUTION REVENUE FLOOR		
Rate Group	**Base Distribution Revenue Decrease**	Since there is no change to the current distribution revenue for the entire group, revenue floor iterations would continue until each rate class received no change in base distribution revenues.
G-2 TOU (Boston Edison)	$(4,637,273)	
G-2 TOU (Cambridge Electric Light)	$-	
G-2 TOU (Commonwealth Electric)	$-	
G-2/T4 (WMA)	$-	
Total Medium C&I	$(4,637,273)	

Rate Group	**Final Base Distribution Revenue Increase**	**Rate Group Base Distribution Revenue Target**	**Total Revenue Increase**	**Rate Group Total Revenue Target**	**Percent Increase in Distribution Revenue**	**Percent Increase in Total Revenue**
G-2 TOU (Boston Edison)	$-	$160,011,887	$(7,471,813)	$765,735,032	-	(0.97)
G-2 TOU (Cambridge Electric Light)	$-	$13,658,395	$2,745,488	$101,955,177	-	2.77

G-2 TOU (Commonwealth Electric)	$-	$10,357,394	$1,669,464	$74,551,481	-	2.29
G-2/T4 (WMA)	$-	$10,647,936	$212,644	$62,244,267	-	0.34
Total Medium C&I	$-	$194,675,611	$(2,844,217)	$1,004,485,957	-	(0.28)

Schedule 10 – Large C&I – For illustrative purposes only

Rate Class	**Total Revenue at Current Rates**	**Base Distribution Revenue at Current Rates**	**Base Rate Transfers**	**Unit Distribution Demand Cost at EROR (per kW)**
Rate G-3 TOU (Boston Edison)	$476,406,008	$70,293,999	$(1,815,952)	$11.27
Rate WR (Boston Edison)	$15,594,462	$1,806	$(47)	
Rate G-3/SB1/MS1/SS1 (Cambridge Electric Light)	$97,910,318	$8,201,486	$(211,875)	$11.27
Rate G-3 TOU (Commonwealth Electric)	$69,184,332	$6,863,136	$(177,300)	$11.27
Rate G-3 TOU (WMA)	$105,722,954	$14,976,652	$(386,902)	$11.27
Rate T-5 TOU (WMA)	$58,199,925	$5,468,667	$(141,276)	$11.27
Total Large C&I	$823,018,000	$105,805,745	$(2,733,351)	

Rate Class	**Base Distribution Revenue at Group Unit Cost**	**Change in Reconciling Revenue**	**Base Distribution Revenue Increase at Group Unit Cost**
Rate G-3 TOU (Boston Edison)	$65,326,833	-$2,036,435	-$4,968,971
Rate WR (Boston Edison)		-$83,047	
Rate G-3/SB1/MS1/SS1 (Cambridge Electric Light)	$15,639,075	$2,146,030	$7,437,589
Rate G-3 TOU (Commonwealth Electric)	$12,013,668	$1,411,501	$5,150,532
Rate G-3 TOU (WMA)	$17,368,563	$387,012	$2,391,912
Rate T-5 TOU (WMA)	$8,827,991	$1,829,587	$3,359,324
Total Large C&I	$119,176,130	$3,654,648	$13,370,386

TOTAL REVENUE CAP						
	ITERATION 1					
Rate Class	**10% Total Revenue Cap**	**Total Revenue Increase Greater Than 10%**	**Base Distribution Revenue Allocator**	**Allocation of Revenues Greater Than 10%**	**Total Revenue Increase After Reallocation**	**Total Revenue Increase Greater Than 10%**
Rate G-3 TOU (Boston Edison)	$47,640,601	$0	$65,326,833	$0	-$7,005,406	$0
Rate WR (Boston Edison)	$1,559,446	$0	$0	$0	-$83,047	$0

Rate G-3/SB1/MS1/SS1 (Cambridge Electric Light)	$9,791,032	$0	$15,639,075	$0	$9,583,619	$0
Rate G-3 TOU (Commonwealth Electric)	$6,918,433	$0	$12,013,668	$0	$6,562,033	$0
Rate G-3 TOU (WMA)	$10,572,295	$0	$17,368,563	$0	$2,778,923	$0
Rate T-5 TOU (WMA)	$5,819,992	$0	$8,827,991	$0	$5,188,912	$0
Total Large C&I	$82,301,800	$0	$119,176,130	$0	$17,025,034	$0

BASE DISTRIBUTION REVENUE CAP						
	ITERATION 1					
Rate Class	**200% Base Distribution Revenue Increase Cap**	**Base Distribution Revenue Increase Greater Than 200%**	**Base Distribution Revenue Allocator**	**Allocation of Base Distribution Revenues Greater Than 200%**	**Base Distribution Revenue Increase After Reallocation**	**Base Distribution Revenue Increase Greater Than 200%**
Rate G-3 TOU (Boston Edison)	$9,403,850	$0	$65,326,833	$13,588,878	$8,619,906	$0
Rate WR (Boston Edison)	$242	$0	$0	$0	$0	$0
Rate G-3/SB1/MS1/SS1 (Cambridge Electric Light)	$1,097,185	$6,340,404	$0	$0	$1,097,185	$0
Rate G-3 TOU (Commonwealth Electric)	$918,142	$4,232,390	$0	$0	$918,142	$0
Rate G-3 TOU (WMA)	$2,003,559	$388,352	$0	$0	$2,003,559	$0
Rate T-5 TOU (WMA)	$731,592	$2,627,732	$0	$0	$731,592	$0
Total Large C&I	$14,154,571	$13,588,878	$65,326,833	$13,588,878	$13,370,386	$0

BASE DISTRIBUTION REVENUE FLOOR					
Rate Group	**Base Distribution Revenue Decrease**	**Final Base Distribution Revenue Increase**	**Rate Group Base Distribution Revenue Target**	**Total Revenue Increase**	**Rate Group Total Revenue Target**
Rate G-3 TOU (Boston Edison)	$0	$8,619,906	$78,913,905	$6,583,472	$482,989,480
Rate WR (Boston Edison)	$0	$0	$1,806	-$83,047	$15,511,416
Rate G-3/SB1/MS1/SS1 (Cambridge Electric Light)	$0	$1,097,185	$9,298,671	$3,243,215	$101,153,534
Rate G-3 TOU (Commonwealth Electric)	$0	$918,142	$7,781,279	$2,329,643	$71,513,975
Rate G-3 TOU (WMA)	$0	$2,003,559	$16,980,211	$2,390,571	$108,113,526
Rate T-5 TOU (WMA)	$0	$731,592	$6,200,259	$2,561,179	$60,761,104
Total Large C&I	$0	$13,370,386	$119,176,130	$17,025,034	$840,043,034

Rate Group	Percent Increase in Distribution Revenue	Percent Increase in Total Revenue
Rate G-3 TOU (Boston Edison)	12.26	1.38
Rate WR (Boston Edison)	-	(0.53)
Rate G-3/SB1/MS1/SS1 (Cambridge Electric Light)	13.38	3.31
Rate G-3 TOU (Commonwealth Electric)	13.38	3.37
Rate G-3 TOU (WMA)	13.38	2.26
Rate T-5 TOU (WMA)	13.38	4.40
Total Large C&I	12.64	2.07

XX. ORDER

Accordingly, after due notice, hearing, opportunity for comment, and consideration, it is

ORDERED: That the tariffs filed by NSTAR Electric Company on January 14, 2022, to become effective February 1, 2022, are DISALLOWED; and it is

FURTHER ORDERED: That NSTAR Electric Company shall file new schedules of rates and charges designed to collect the cost of service as set forth in the Schedules above; and it is

FURTHER ORDERED: That NSTAR Electric Company shall file all rates and charges required by this Order and shall design all rates in compliance with this Order; and it is

FURTHER ORDERED: That NSTAR Electric Company shall comply with all other directives contained in this Order; and it is

FURTHER ORDERED: That the new rates shall apply to electricity consumed on or after January 1, 2023, but, unless otherwise ordered by the Department, shall not become effective earlier than seven days after the rates are filed with supporting data demonstrating that such rates comply with this Order.

By Order of the Department,

/s/

Matthew H. Nelson, Chair

/s/

Robert E. Hayden, Commissioner

/s/

Cecile M. Fraser, Commissioner

An appeal as to matters of law from any final decision, order or ruling of the Commission may be taken to the Supreme Judicial Court by an aggrieved party in interest by the filing of a written petition praying that the Order of the Commission be modified or set aside in whole or in part. Such petition for appeal shall be filed with the Secretary of the Commission within twenty days after the date of service of the decision, order or ruling of the Commission, or within such further time as the Commission may allow upon request filed prior to the expiration of the twenty days after the date of service of said decision, order or ruling. Within ten days after such petition has been filed, the appealing party shall enter the appeal in the Supreme Judicial Court sitting in Suffolk County by filing a copy thereof with the Clerk of said Court. G.L. c. 25, § 5.

Powell Reaffirms Fed Is Waiting to Cut Interest Rates in Testimony on Capitol Hill

The central bank chairman says inflation remains above the Fed’s target and that the economy is humming along.

By Tim Smart | March 6, 2024 |

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Federal Reserve Chairman Jerome Powell stuck to his script that it is not yet time to begin cutting interest rates on Wednesday in the first of two appearances this week on Capitol Hill.

▸▸ **READ:** ADP: Solid Job, Pay Gains in February

The Fed has taken interest levels to their highest in decades in a battle to bring inflation down to the central bank's 2% annual target. Although significant progress has been made – consumer prices peaked around 9% annually in the summer of 2022 – prices remain sticky, especially for items like housing and groceries.

A stronger-than-expected economy to start 2024 has delayed the likely start of cuts to interest rates that were once thought to be on the table for this month but now seem more likely in May or June.

View All 192 Images

“The Committee does not expect that it will be appropriate to reduce the target range until it has gained greater confidence that inflation is moving sustainably toward 2 percent,” Powell said in his opening remarks to the House Committee on Financial Services. The hearing is one of two Powell will attend as part of a mandated, six-month update on monetary policy.

“We remain committed to bringing inflation back down to our 2% goal and to keeping longer-term inflation expectations well anchored,” Powell added. “Restoring price stability is essential to set the stage for achieving maximum employment and stable prices over the longer run.”

⏩ **READ:** This Week: Jobs Data, Powell on the Hill

One component of the Fed’s equation is the resilience of the labor market. January saw 353,000 new jobs created and markets are looking to Friday's monthly report on February jobs from the Labor Department. On Wednesday, private payroll firm ADP reported that 140,000 jobs were added last month with most of the gains coming in the services sector of the economy.

“The labor market remains relatively tight, but supply and demand conditions have continued to come into better balance,” Powell said. “Since the middle of last year, payroll job gains have averaged 239,000 jobs per month, and the unemployment rate has remained near historical lows, at 3.7 percent. Strong job creation has been accompanied by an increase in the supply of workers, particularly among individuals aged 25 to 54, and a continued strong pace of immigration. Job vacancies have declined, and nominal wage growth has been easing.”

▶▶ **READ:** Consumers Sanguine About Econ Outlook

Powell and other Fed officials have repeatedly said they will judge whether to begin lowering interest rates on the state of incoming economic data. Officials are fearful of cutting rates too soon. Meanwhile, the economy and financial markets are performing strongly, undercutting the argument that the Fed’s interest rate policy is too restrictive.

Indeed, the Federal Reserve Bank of Atlanta’s GDPNow forecast has first-quarter growth in gross domestic product at 2.1%, a number that is consistent with a growing economy.

“The Fed will likely find some comfort in the cooler pace of job growth and more benign wage reading,” said Lydia Boussour, EY senior economist. “While we maintain our view that the first Fed rate cut will come in May, we acknowledge the risk that the recent strength in inflation data could provide hawkish Fed officials with the necessary justification to delay the onset of the easing cycle until mid-year.”

▶▶ **READ:** Key Fed Inflation Measure Rose in January

The growing economy and resilient labor market is accompanied by a stock market that is trading near record highs, although it did sell off sharply on Tuesday. In particular, the rally since late last year is concentrated on big-name tech stocks that are believed to be beneficiaries of fueled increase in productivity.

In his testimony, Powell did acknowledge that interest rates are “likely” at their peak for this economic cycle.

“We think Powell has got it right,” said Chris Rupkey, chief economist at FWDBONDS. “While policymakers struggle with the timing of the rate cuts they forecast for this year, interest rates at current levels are balanced between being behind the curve on the downside risks to the economy and growth, and not being high enough to keep inflation in check. The ADP jobs report in February shows companies continue to hire so the outlook for the economy cannot be all that bad and the labor market remains tight.”

Join the Conversation

See Comments

Tags: Federal Reserve, Jerome Powell, interest rates, economy

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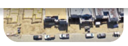
Gas and Housing Prices Drive Inflation Higher in February

The Labor Market Keeps Rolling as 275K Jobs Added in February, Beating Expectations



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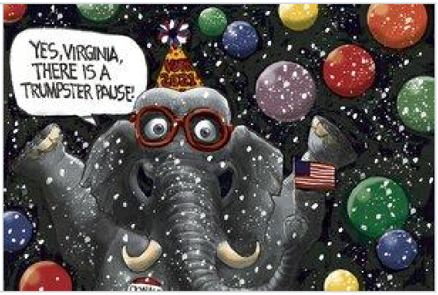

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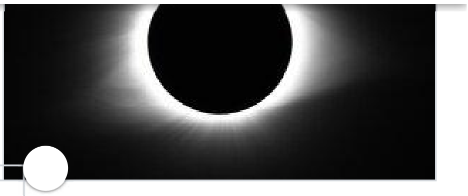
Cecelia Smith-Schoenwalder March 27, 2024



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Before Commissioners:

T.W. Patch, Chairman
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In the Matter of the Revenue Requirement and Cost of Service Study Designated as TA381-1 Filed by ALASKA ELECTRIC LIGHT AND POWER COMPANY)

U-10-29

ORDER NO. 15

ORDER ACCEPTING PARTIAL STIPULATION, DETERMINING REVENUE REQUIREMENT AND RATE DESIGN ISSUES, APPROVING PERMANENT RATES, AND APPROVING TARIFF SHEETS

BY THE COMMISSION:

Summary

We accept the unopposed partial stipulation filed in this matter. We determine the revenue requirement and rate design issues for Alaska Electric Light and Power Company (AEL&P).

Background

AEL&P filed TA381-1, requesting a 24 percent permanent across-the-board rate increase to base demand and energy charges.[1] This request was based upon a proposed revenue requirement of $43,135,748 and projected revenue deficiency of $15,827,289.[2] AEL&P asserted that this revenue deficiency justified a 59 percent increase in the base rates charged firm customers.[3] AEL&P proposed to mitigate this

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[1] *Tariff Advice Letter No. 381-1*, filed May 3, 2010 (TA381-1), at 4.

[2] TA381-1 at 3; Revenue Requirement Study, Schedule 5.

[3] TA381-1 at 3.

increase by moving recognition of $3,461,863 of interruptible energy sales revenue from its cost of power adjustment (COPA) mechanism into base rate calculations; by including $3,191,898 of projected future interruptible energy sales revenue in base rate calculations; and by forgoing recovery of approximately $3,300,000 of its revenue requirement.[4] With these adjustments, AEL&P projected a total revenue deficiency of 22.1 percent,[5] or $5,873,528.[6] AEL&P has proposed recovering this revenue deficiency through the requested 24 percent increase in energy and demand charges, with no change to its customer charges.[7]

AEL&P requested an interim and refundable across-the-board demand and energy charge rate increase of 20 percent, effective for billings rendered after June 18, 2010, in the event that we suspend TA381-1 for further investigation.[8] TA381-1 included a cost-of-service study,[9] a revenue requirement study,[10] and proposed tariff sheets. AEL&P also submitted prefiled direct testimony of Timothy D. McLeod,[11] Constance S. Hulbert,[12] Thomas M. Zepp,[13] and David A. Gray.[14]

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[4] TA381-1 at 3-4.

[5] TA381-1 at 3.

[6] $15,827,289 - $3,461,863 - $3,191,898 - $3,300,000 = $5,873,528.

[7] *See* TA381-1 at 4.

[8] TA381-1 at 4.

[9] *Alaska Electric Light and Power Company Cost of Service Study*, filed May 3, 2010 (COSS).

[10] *Alaska Electric Light and Power Company Revenue Requirement Study*, filed May 3, 2010 (RRS).

[11] *Prefiled Direct Testimony of Timothy D. McLeod*, admitted May 10, 2011 (T-5 McLeod Direct).

[12] *Prefiled Direct Testimony of Constance S. Hulbert*, admitted May 11, 2011 (T-7 Hulbert Direct).

[13] *Prefiled Direct Testimony of Thomas M. Zepp*, admitted May 11, 2011 (T-9 Zepp Direct).

[14] *Prefiled Direct Testimony of David A. Gray*, admitted May 9, 2011 (T-1 Gray Direct).

We issued public notice of the request.[15] We received a multitude of comments regarding this requested rate increase or requesting that a public hearing on this increase be held in Juneau before a decision on AEL&P's request was reached.[16] We held a consumer input hearing in Juneau on June 15, 2010, at which approximately fifty oral and written comments regarding AEL&P's proposed rate increase were received**.**[17]

We suspended TA381-1 into this docket and denied AEL&P's request for an interim rate increase.[18] We scheduled a hearing on AEL&P's request for an interim rate increase.[19] AEL&P submitted a brief on interim rate increase issues,[20] and an errata to TA381-1.[21] AEL&P employees Kenneth S. Willis, Hulbert, and McLeod testified at the interim rate increase public hearing.[22] With these witnesses, AEL&P introduced twenty-one exhibits into the record.[23]

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[15] *Notice of Utility Tariff Filing,* dated May 5, 2010.

[16] *See* Public comments, filed in TA381-1.

[17] *The transcript of this hearing can be viewed by following the link to our website and clicking on the "Documents" Tab:* http://rca.alaska.gov/RCAWeb/Dockets/DocketDetails.aspx?id=dfb6efef-bbb4-42a7-951d-6e1209b20ee0

[18] Order U-10-29(1), *Order Suspending TA381-1, Denying Request for Interim Rates, Scheduling a Hearing on Interim Rates, Scheduling a Prehearing Conference, Inviting Petitions for Intervention and Participation by the Attorney General, Addressing Timeline for Decision, Designating Commission Panel, and Appointing Administrative Law Judge*, dated June 17, 2010 (Order U-10-29(1)), at 2-6.

[19] Order U-10-29(1) at 6.

[20] *Alaska Electric Light and Power Company Interim Rate Relief Request Prehearing Brief*, filed July 6, 2010.

[21] *Errata to Tariff Advice No. 381-1*, filed July 6, 2010.

[22] Public Hearing, July 6, 2010. Tr. 30-87.

[23] Exhibits H-1 through H-21, admitted July 6, 2010. Tr. 24.

We granted AEL&P a 20 percent interim and refundable rate increase, effective July 16, 2010.[24] The Attorney General (AG) elected to participate in this proceeding.[25] The Juneau Peoples' Power Project (J3P) petitioned to intervene in this proceeding.[26] AEL&P submitted corrections to TA381-1 and the prefiled testimony of Gray.[27] We granted J3P party status in this proceeding.[28]

J3P submitted prefiled testimony of Randall A. Sutak.[29] The AG submitted prefiled testimony of Janet K. Fairchild[30] and David C. Parcell.[31] The City and Borough of Juneau requested that we hold the hearing for this proceeding in Juneau.[32] We ordered that the hearing in this proceeding be held in Juneau.[33] AEL&P

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[24] Order U-10-29(2), *Order Granting Interim and Refundable Rate Increase, Approving Tariff Sheets and Requiring Filing*, dated July 16, 2010, as corrected by *Errata Notice to Order U-10-29(2)* (Order U-10-29(2)).

[25] *Notice of Election to Participate*, filed July 19, 2010.

[26] *Juneau Peoples' Power Project, Bill Burk, Vincent Hayden, John and Carolyn Martin, Randy Sutak, and Cheryl K. Moralez Joint Petition to Intervene*, filed July 19, 2010.

[27] *AELP's Errata to Tariff Advice No. 381-1*, filed August 13, 2010 (Second Errata). This errata also refers to changes to T-1 Gray.

[28] Order U-10-29(4), *Order Granting Petition to Intervene in Part, Requiring Filings, and Scheduling Prehearing Conference*, dated September 27, 2010.

[29] *Prefiled Direct Testimony of Randall A. Sutak*, admitted May 12, 2011 (T-13 Sutak Direct).

[30] *Prefiled Testimony of Janet K. Fairchild*, admitted May 12, 2011 (T-11 Fairchild Direct).

[31] *Prefiled Direct Testimony of David C. Parcell on Behalf of the Attorney General*: admitted May 12, 2011; Notice of Filing Errata to Prefiled Testimony of David Parcell admitted May 12, 2011(T-12 Parcell Direct). Both documents are admitted as one exhibit.

[32] Correspondence from L. Sica, Municipal Clerk, City and Borough of Juneau, filed February 3, 2011.

[33] Order U-10-29(9), *Order Modifying Procedural Schedule*, dated March 3, 2011.

submitted prefiled reply testimony of McLeod,[34] Hulbert,[35] Zepp,[36] Gray,[37] Willis,[38] and Joseph Perkins.[39]

AEL&P submitted revised prefiled reply testimony of Willis[40] and Perkins.[41] AEL&P and the AG filed a stipulation between themselves resolving some of the issues raised in the testimony of Fairchild and Hulbert.[42] J3P did not oppose our acceptance of this stipulation.[43] The AG submitted corrections to the prefiled testimony of Parcell and Fairchild.[44] J3P submitted a correction to the prefiled testimony of Sutak.[45] The parties filed statements of issues.[46] J3P requested subpoenas for two additional witnesses.[47] On an expedited basis, we denied J3P's request for

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[34] *Reply Testimony of Timothy D. McLeod*, admitted May 10, 2011 (T-6 McLeod Reply).

[35] *Prefiled Reply Testimony of Constance S. Hulbert*, admitted May 11, 2011 (T-8 Hulbert Reply).

[36] *Reply Testimony of Thomas M. Zepp*, admitted May 11, 2011 (T-10 Zepp Reply).

[37] *Prefiled Reply Testimony of David A. Gray*, admitted May 9, 2011 (T-2 Gray Reply).

[38] *Prefiled Reply Testimony of K. Scott Willis*, filed March 4, 2011 (withdrawn on April 13, 2011).

[39] *Prefiled Reply Testimony of Joseph Perkins*, filed March 4, 2011 (withdrawn on April 13, 2011).

[40] *Prefiled Reply Testimony of K. Scott Willis (Revised 4/13/11)*, admitted May 9, 2011 (T-3 Willis Revised Reply).

[41] *Prefiled Reply Testimony of Joseph Perkins (Revised 4/13/11)*, admitted May 10, 2011 (T-4 Perkins Revised Reply).

[42] *Unopposed Partial Stipulation*, filed April 28, 2011 (Stipulation).

[43] *Settlement Report*, filed April 28, 2011 (Settlement Report), at 2.

[44] *Notice of Filing Errata to Prefiled Testimony of David A. Parcell*, filed May 2, 2011; *Notice of Filing Errata to* [Fairchild] *Prefiled Testimony*, filed May 2, 2011.

[45] *Errata of Randall A. Sutak's Testimony*, filed May 3, 2011.

[46] *Attorney General's Statement of Issues*, filed May 2, 2011; *AELP's Statement of Issues*, filed May 2, 2011; *Juneau Peoples' Power Project's Statement of Issues*, filed May 3, 2011.

[47] *Juneau Peoples' Power Project's Witness List and Request for Subpeona* [*sic*] *of Additional Witnesses*, filed May 3, 2011.

subpoenas.[48] The public hearing in this proceeding was held in the City and Borough of Juneau Assembly Chambers on May 9 through 13, 2011. Additional oral public comment was received on the morning of May 10, 2011.[49] We also received additional written public comments.[50] With the consent of the parties, we extended the statutory deadline for issuance of a final order in this proceeding.[51]

Discussion

Acceptance of Stipulation Reducing Revenue Requirement

Before the hearing, AEL&P and the AG stipulated to a decrease in AEL&P's pro forma test year revenue requirement.[52] The stipulation proposed a reduction of both AEL&P's operating expenses and rate base. The reductions were based on proposed adjustments presented in AG witness Fairchild's testimony. Stipulated decreases to AEL&P's amortization expense, property tax allowance, bad debt expense, and miscellaneous expense result in a $292,259 reduction to operating expenses. Stipulated decreases associated with prepayments, deferred debt debit, and cash working capital allowance result in a $1,810,265 reduction to AEL&P's pro forma rate base. J3P, while not a signatory, does not object to the stipulation between AEL&P and the AG.[53]

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[48] Order U-10-29(12), *Order Accepting Late-Filed Documents, Denying Request for Subpoena of Additional Witnesses, and Granting Request for Expedited Consideration*, dated May 6, 2011.

[49] Tr. 381-394.

[50] Correspondence from B. Donnelly, filed May 2, 2011; Correspondence from H. Zimmerman, filed May 12, 2011.

[51] Order U-10-29(13), *Order Extending Statutory Timeline with Consent of Parties and Extending Tariff Suspension*, dated July 27, 2011. Order U-10-29(14), *Order Extending Statutory Timeline with Consent of Parties and Extending Tariff Suspension,* dated August 26, 2011.

[52] Stipulation.

[53] *Settlement Report*, filed April 28, 2011, at 2.

Parties may stipulate among themselves to the resolution of issues outstanding in a proceeding.[54] If we accept the stipulation, the parties are bound by its terms. The stipulation between AEL&P and the AG proposed to reduce AEL&P's operating expenses and rate base. Further, the stipulation reduced the number of issues to be addressed at hearing and helped to conserve the parties' and the commission's time and resources. The prefiled testimony and exhibits relied on in the stipulation were admitted as evidence in this proceeding[55] and no party of record opposes our acceptance of the stipulation. Accordingly, we accept the stipulation, subject to the express condition that no issue shall be considered to have been finally determined or adjudicated by virtue of our acceptance of the stipulation. A copy of the stipulation is attached to this order as Appendix A.

Lake Dorothy Hydroelectric Project Prudence

One of the two main drivers behind AEL&P's requested rate increase is the increase in its hydroelectric costs due to the Lake Dorothy Hydroelectric Project (Lake Dorothy) project going into service.[56] J3P presented allegations asserting that AEL&P's decision to construct Lake Dorothy was not prudent.[57] The AG, who participates in our proceedings as a public advocate when he determines that participation is in the public interest,[58] presented no argument or evidence challenging

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[54] 3 AAC 48.166.

[55] Public hearings held July 6, 2010; May 9, 2011, through May 13, 2011 (admission of Exhibits H-1 through H-39, H-41 through H-43, H-45 through H-90, and T-1 through T-13).

[56] TA381-1 at 2.

[57] *See, e.g., Juneau People's Power Project's Statement of Issues*, filed May 3, 2011, at 1.

[58] AS 44.23.020(e).

the prudence of AEL&P's decision to build Lake Dorothy. AEL&P responded with argument and evidence supporting the prudence of its decisions.[59]

The Federal Energy Regulatory Commission (FERC) has developed an approach for addressing challenges to the prudence of costs incurred by a utility. Under that approach, a utility's costs are presumed to be prudently incurred. It is up to the party challenging prudence to make a substantial showing that the challenged costs were imprudently incurred.

The approach taken by the FERC is consistent with prior decisions from the Alaska Public Utilities Commission (APUC), our predecessor agency. In addressing a challenge to expenses incurred by Kenai Pipe Line Company the APUC stated, "It is an extraordinary measure for a regulatory agency to entirely disallow costs that were actually and necessarily incurred to provide service. A disallowance of such costs would normally be made when the costs are imprudently incurred by the carrier."[60]

Based on this guidance, we will review the arguments and evidence presented by J3P to determine whether they have created a serious doubt as to the prudence of AEL&P's decision to construct Lake Dorothy (and therefore incur expenditures). A management decision is imprudent if a reasonable manager would not have made that decision.[61] Only if J3P has created a serious doubt will we then proceed to determine whether AEL&P has dispelled this doubt and proven the decision prudent.

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[59] T-3 Willis Revised Reply; T-4 Perkins Revised Reply; T-6 McLeod Reply at 2-6; T-8 Hulbert Reply at 2-10.

[60] Order P-91-2(11)/P-85-1(19), *Order Prescribing Rate Base Methodology; Resolving Other Disputed Issues; Directing Kenai Pipe Line Company to File Revised Revenue Requirement and Rates for Period Beginning June 1, 1991; Striking DR&R Testimony; Establishing Schedule for Phase II of this Proceeding; and Extending Suspension Period*, dated December 1, 1992 (Order P-91-2(1)), at 47.

[61] Order P-91-2(11) at 47.

Evidence Regarding Prudence

J3P provided testimony that Hecla Greens Creek Mining Company (Greens Creek) was purchasing more interruptible, or excess, energy per year than Lake Dorothy was budgeted to produce.[62] J3P asserts that this is evidence that Lake Dorothy is not used and useful for AEL&P's firm customers, and thus Lake Dorothy costs should not be recoverable through rates charged firm customers.[63]

AEL&P presented evidence that its decision to develop Lake Dorothy was prudent. One of the exhibits presented by AEL&P was the *Juneau 20 Year Power Supply Plan*, dated December 1984.[64] This power supply plan discussed load growth projections and power supply options available for the Juneau area. The plan found that construction of Lake Dorothy had several advantages over other potential generation resource additions.[65] AEL&P also introduced the 1990 *Juneau 20-Year Power Supply Plan Update*.[66] This update identified Lake Dorothy as the lowest-cost generation option over its life rotation.[67] The 1990 update recommended proceeding with the FERC process for licensing Lake Dorothy.[68] AEL&P received a FERC preliminary permit for Lake Dorothy in 1996.[69] AEL&P received a FERC license authorizing construction of Lake Dorothy in 2003.[70]

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[62] T-13 Sutak Direct at 5.

[63] T-13 Sutak Direct at 5.

[64] Exhibit H-3.

[65] Exhibit H-3, Section 6 at 2-4.

[66] Exhibit H-4.

[67] Exhibit H-4, Section ES at 3-4.

[68] Exhibit H-4, Section VI at 3-4.

[69] Tr. 43; Exhibit H-2; T-3 Willis Revised Reply at 7, KSW-5.

[70] Tr. 43; Exhibit H-2; T-3 Willis Revised Reply at 7, KSW-5.

AEL&P introduced a 2006 consulting engineer's report prepared by CH2MHill for AEL&P and the Alaska Industrial Development and Export Authority (AIDEA).[71] The report reviewed AEL&P's load forecast and existing generation resources.[72] Further, the engineer's report investigated the Lake Dorothy design, output projections, economic projections, and risks.[73] CH2MHill found that the Lake Dorothy design and projections were reasonable and that the risks were prudently accounted for.[74]

AEL&P projects that production by Lake Dorothy will reduce the scheduled use of diesel generation by 77 hours, from 113 hours to 36 hours, in an average water year.[75] AEL&P estimates that this reduced use of diesel generation will result in annual savings of approximately $8,504 on diesel generator overhaul costs.[76] AEL&P estimated that Lake Dorothy would, on average, reduce the amount of annual diesel generation by 3,318,405 kWh.[77] AEL&P estimates that, at the March 3, 2011, price of $3.54/gallon of diesel, this would reduce the amount of annual diesel purchases by $903,627.[78] Total Lake Dorothy output was estimated to be 74,500,000 kWh during an average water year, and 62,800,000 kWh during a dry year.[79]

After reviewing the assertions presented by J3P, we are unable to find that J3P presented a showing of inefficiency or improvidence sufficient to raise a serious

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[71] Exhibit H-5.

[72] Exhibit H-5 at 3-18.

[73] Exhibit H-5 at 18-39.

[74] Exhibit H-5 at 40.

[75] Exhibit H-47; H-62 at 1.

[76] Exhibit H-62 at 1.

[77] T-8 Hulbert Reply, CSH-4.

[78] T-8 Hulbert Reply at 3.

[79] Exhibit H-5 at 20.

doubt as to AEL&P's prudence in developing Lake Dorothy. Further, AEL&P has made a sufficient showing that its decision to construct Lake Dorothy was prudent.

Lake Dorothy Construction Management Prudence

The estimated construction cost for Lake Dorothy was $53.5 million.[80] The final cost was $78.5 million.[81] J3P alleges that AEL&P's construction management of Lake Dorothy was inconsistent with prudent utility practice, resulting in the final costs exceeding the original budget by $20 million.[82] The AG presented no argument or evidence challenging the prudence of AEL&P's construction management.

Challenges to cost overruns incurred on a construction project are reviewed based on a similar standard to the prudence standard articulated above. The APUC addressed construction cost overruns in Order U-83-53(32).[83] In that decision the APUC addressed alleged imprudent or unnecessary costs incurred on a construction project. The alleged imprudent or unnecessary costs were tied to a design error. The APUC stated that recovery for imprudent or unnecessary costs should be disallowed.[84] However, they denied the prudence challenge and allowed the recovery of costs based on a finding that the amount of the cost overrun attributable to the design error was difficult to quantify and that the record was insufficient to support a finding of imprudence.[85] The APUC's approach is consistent with the FERC prudence standard identified above. Therefore, we conduct our review of the challenge to the prudence of AEL&P's construction management using the same standard articulated above.

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[80] Exhibit H-5 at 30.

[81] T-4 Perkins Revised Reply at 5.

[82] T-13 Sutak Direct at 2.

[83] Order U-83-53(32), *Order Deciding Substantive Revenue Requirement Issues and Requiring Permanent Rate and Applicable Refund Determinations*, dated December 4, 1986 (Order U-83-53(32)), at 13-16.

[84] Order U-83-53(32) at 15.

[85] Order U-83-53(32) at 15-16.

J3P asserts that the cost overrun for Lake Dorothy was due to imprudent construction management practices.[86] J3P specifically alleges that cost overruns resulted from AEL&P converting a low bid contract to a cost plus contract,[87] AEL&P's failure to prorate the materials portion of equipment repairs,[88] AEL&P's use of a project manager who was not a licensed engineer,[89] AEL&P's use of plans that had not been stamped by a professional engineer,[90] AEL&P's payment for conjugal visits for the benefit of contractor employees,[91] and AEL&P's failure to order steel for the project before prices increased.[92]

AEL&P disputed these assertions with the testimony of Joseph Perkins.[93] Perkins found that five specific components of the project accounted for $23.8 million of the $25 million cost overrun.[94] With the exception of the change from gasketed steel penstock to welded steel penstock and the increase in steel prices,[95] the site conditions resulting in these cost overruns were identified as known risks in the pre-construction consulting engineer's report.[96] Perkins testified that some of the design changes related to changed site conditions were required by the FERC Board of Consultants and the resulting additional costs could not be avoided.[97] Unanticipated increases in the

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[86] T-13 Sutak Direct at 9-12.

[87] T-13 Sutak Direct at 9-10.

[88] T-13 Sutak Direct at 9.

[89] T-13 Sutak Direct at 10.

[90] T-13 Sutak Direct at 10-11.

[91] T-13 SutakDirect at 11.

[92] T-13 SutakDirect at 12.

[93] T-4 Perkins Revised Reply, Tr. 451-479.

[94] T-4 Perkins Revised Replyat 5.

[95] T-4 Perkins Revised Reply at 7.

[96] Exhibit H-5 at 29-30.

[97] Tr. 475-476.

price of steel for transmission towers and the cost of transportation apparently caused some portion of the remaining cost overrun.[98]

Perkins testified that the lack of detailed field investigation of site conditions before construction contributed to the low estimate, but did not significantly contribute to increased construction costs.[99] Specifically, he testified that if a detailed geotechnical investigation had been conducted, the project design and corresponding cost estimate would have been revised to reflect substantially what was actually constructed.[100] He also testified that conducting the additional geotechnical investigation at Lake Dorothy would have been extremely expensive.[101] Perkins concluded that, based upon the substantial geotechnical information available regarding the Lake Dorothy project, it was prudent for AEL&P to proceed with project construction without incurring the expense of conducting further geotechnical investigation.[102] He also testified that AEL&P's conversion of fixed price contracts to cost-plus contracts was prudent due to the changed conditions encountered during the construction of Lake Dorothy.[103]

In response to J3P's specific allegations of mismanagement, Perkins testified that it was not unusual for competent project managers to not be professional engineers and offered his professional opinion that Lake Dorothy was a well managed project.[104] Perkins testified that it would be unusual for project owners such as AEL&P

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[98] Tr. 109-111.

[99] T-4 Perkins Revised Reply at 9-11.

[100] T-4 Perkins Revised Reply at 9.

[101] T-4 Perkins Revised Reply at 9.

[102] T-4 Perkins Revised Reply at 9-13.

[103] T-4 Perkins Revised Reply at 17-20.

[104] T-4 Perkins Revised Reply at 20-21; Tr. 478.

to purchase raw steel in advance of a construction project.[105] Perkins also testified AEL&P's use of unstamped plans did not cause any construction problems.[106] AEL&P witness Willis testified that AEL&P did not pay for conjugal visits to contractor employees.[107]

J3P extensively cross-examined AEL&P witnesses Willis and Perkins.[108] After reviewing the assertions presented by J3P regarding AEL&P's construction management and the responses of Willis and Perkins on cross-examination, we are unable to find that J3P presented a showing of imprudence sufficient to raise a serious doubt as to AEL&P's construction management. Further, AEL&P has made a sufficient showing that its construction management practices were prudent.

Price Charged Greens Creek for Interruptible Energy

AEL&P entered into an interruptible power sale agreement with Greens Creek in October 2005.[109] We approved the Greens Creek PSA in October, 2005.[110] J3P asserts that the Period 1 rate discount provided to Greens Creek pursuant to the Greens Creek PSA was unreasonably preferential to Greens Creek.[111] The Period I rates were implemented when interruptible energy sales to Greens Creek began in September 2006[112] and expired pursuant to the terms of the Greens Creek PSA two

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[105] T-4 Perkins Revised Reply at 21-22.

[106] T-4 Perkins Revised Reply at 23-24.

[107] T-3 Willis Revised Reply at 20.

[108] Tr. at 325-437 (Willis), 451-468 (Perkins).

[109] T-11 Fairchild Direct, JKF-11, *Agreement for the Sale and Purchase of Interruptible Energy Between Alaska Electric Light and Power Company and Kennecott Greens Creek Mining Company*, effective October 3, 2005 (Greens Creek PSA).

[110] Letter Order No. L0500581, dated October 4, 2005 (L0500581), in TA334-1.

[111] T-13 Sutak Direct at 7-8; Greens Creek PSA at 5, 10, Exhibit D.

[112] TA347-1, Exhibit 3.

months later.[113] Pursuant to the prohibition on retroactive rate making, there appears to be no action that we could take regarding the Period I rates charged Greens Creek, even if we agreed with J3P's assertion.[114]

J3P also asserts that the price charged under the Greens Creek PSA for Period 3 interruptible energy is unreasonably low.[115] The AG evaluated the price for interruptible power charged by AEL&P to Greens Creek and compared it with the interruptible rate offered by another electric utility, Municipality of Anchorage d/b/a Municipal Light & Power (ML&P).[116] According to the AG, both utilities offer interruptible service at a discount from their rate for firm service. The AG determined that AEL&P offers less of a discount for interruptible service, on a percentage basis, than ML&P. Therefore, the AG determined that the Period 3 rate charged to Greens Creek is reasonable.

Based upon our examination of the Greens Creek PSA, we find that the cost of Lake Dorothy energy was intended to serve as a proxy price for all Period 3 energy sold to Greens Creek.[117] This proxy price was capped at $0.10/kWh for the first seven years of Lake Dorothy commercial operation.[118] For interruptible energy, our standard has been that prices must cover all incremental costs of generating the energy, plus a margin.[119] The estimated total annual cost of Lake Dorothy included

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[113] T-3 Willis Revised Reply at 9.

[114] *Matanuska Electric Ass'n, Inc. v. Chugach Electric Ass'n, Inc.*, 53 P.3d 578, 583-587 (Alaska 2002).

[115] T-13 Sutak Direct at 7-8; Greens Creek PSA at 5, 11, Exhibit D.

[116] T-11 Fairchild Direct at 41-42.

[117] Greens Creek PSA at 37-38

[118] Greens Creek PSA at 34-35.

[119] *See* Order U-93-94(2), *Order Approving Contract and Closing Docket*, dated May 9, 1994 (Order U-93-94(2)), Appendix at 10 (discussing typical pricing for interruptible energy contracts).

approximately $400,000 in operating and maintenance costs[120] that do not appear fixed, and thus could be considered variable.[121] At a projected average annual output of 74,500,000 kWh,[122] Lake Dorothy variable costs would be less than $0.01/kWh.[123] The $0.10/kWh Greens Creek is paying AEL&P for interruptible energy substantially exceeds Lake Dorothy average variable costs. Therefore, we find that the Period 3 rate AEL&P charges Greens Creek for interruptible power is reasonable.

Lake Dorothy Allowance For Funds Used During Construction (AFUDC)

The reply testimony of AEL&P witness Hulbert summarizes the forty-year history of the regulatory use of an "Allowance For Funds Used During Construction" (AFUDC).[124] AFUDC came into use in jurisdictions such as ours, which do not permit a utility engaged in a multi-year construction project to include those costs in rates incrementally each year. Instead, those costs are reflected in rates after the completion of the project. AFUDC was therefore developed as an annual estimate of the utility's finance costs related to an ongoing construction project.[125] Upon project completion those annual AFUDC amounts are added to the other costs of the project for inclusion in the utility's rate base and then recovered through rates.[126]

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[120] Exhibit H-5 at 30-31 ($374,063 in 2009 with 3 percent inflation factor).

[121] *See* Order U-93-94(2), Appendix at 10.

[122] Exhibit H-5 at 20 (expressed as 74.5 gWh).

[123] $400,000 per year divided by 74,500,000 kWh per year = $0.0054/kwh.

[124] T-8 (Hulbert Reply) at 39 – 43.

[125] Construction of Phase I of the Lake Dorothy Hydro Project began in May 2006 and the project was not declared operational until August 2009. T-3 (Willis Reply), KSW-5 at 2.

[126] "When utilities are not allowed to earn a return to cover their construction financing costs during the construction period, they are allowed to capitalize the financing costs for future recovery through an allowance for funds used during construction (AFUDC)." T-8 (Hulbert Reply) at 41-42 *citing* Hahne, Accounting for Public Utilities at 4.04[4].

Our regulations provide for the calculation of AFUDC by reference to the rules of the Federal Energy Regulatory Commission (FERC). Specifically, our regulations refer to the FERC uniform system of accounts in effect as of January 1, 1982.[127] The AFUDC-relevant part of that uniform system of accounts is found in 18 C.F.R. Part 101, Electric Plant Instructions. Paragraph 3 of the FERC uniform system of accounts states in part:

> (17) *Allowance for funds used during construction* (Major and Nonmajor Utilities) includes the net cost for the period of construction of borrowed funds used for construction purposes and a reasonable rate on other funds when so used, *not to exceed*, without prior approval of the Commission, allowances computed in accordance with the formula prescribed in paragraph (a) of this subparagraph. No allowance for funds used during construction charges shall be included in these accounts upon expenditures for construction projects which have been abandoned.[128] (Emphasis added.)

Subparagraph (a) of Paragraph 3(17) sets out the general formula for calculating AFUDC. Subparagraph (b) of Paragraph 3(17) requires annual updating. The FERC adopted Order No. 561 in 1977, further explaining its interpretation of this regulation.[129]

AEL&P's proposed 2009 test year revenue requirement included a proposed return of $11,685,832 on an average rate base of $112,471,918.[130] This rate base included a total AFUDC of $9,365,205 for the Lake Dorothy Hydro project.[131] Hulbert testified AEL&P precisely followed the prescribed formula for calculating AFUDC. She believed the formula is intended to be a practical, standardized methodology for calculating AFUDC. Each of AEL&P's annual AFUDC calculations was

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[127] 3 AAC 48.277(a)(10).

[128] 18 C.F.R. Part 101, Electric Plant Instructions, at ¶3(17).

[129] Exhibit H-63.

[130] RRS, Schedule 5.

[131] T-11 (Fairchild Direct) at 26, JKF-6, JKF-9.

reviewed by accounting firm KPMG and then included in AEL&P's audited financial statements.[132]

Fairchild acknowledged that Paragraph 3(17) applied to AEL&P's AFUDC calculations and did not assert that AEL&P had incorrectly calculated the AFUDC for the Lake Dorothy hydro project when using the formula under the FERC uniform system of accounts.[133] Nonetheless, the AG disputed the manner in which AEL&P had calculated AFUDC. The AG asserted that the "not to exceed" language in the instruction quoted above indicates we have discretion to reduce the amount of AFUDC (for a specific project) below that which would otherwise be calculated using the general formula of the FERC uniform system of accounts.[134] The AG further asserted that use of our discretion would be appropriate here because certain bond funds used to finance the project were readily distinguishable. Using the general formula under the FERC uniform system of accounts to calculate the AFUDC amounts, the AG argued, overstated the Lake Dorothy construction financing costs actually incurred.[135]

Fairchild therefore recommended an alternative calculation methodology that would reduce the total AFUDC for the Lake Dorothy hydro project to $5,850,106.[136] The AG proposed that the AFUDC should be re-calculated using first the amount and lower interest rate[137] of the AIDEA conduit bonds[138] AEL&P had used to partially finance the project. Only after project spending exceeded the full amount of those funds

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[132] T-8 (Hulbert Reply) at 39 – 40.

[133] T-11 (Fairchild) at 27-28, JKF-7.

[134] T-11 (Fairchild) at 27-29.

[135] T-11 (Fairchild) at 28.

[136] T-11 (Fairchild) at 28-29, JKF-9.

[137] $46,655,000 at 5.05 percent interest rate. T-11 (Fairchild Direct) at 28.

[138] AIDEA agreed to lend AEL&P up to $60 million for construction of Lake Dorothy by issuing tax exempt conduit revenue bonds. Exhibit H-36 at 2-3, Exhibit H-37 at 2-3.

should subsequent AFUDC calculations have been calculated taking into account the higher costs[139] of other sources of funds used including AEL&P's equity contributions.[140]

Hulbert testified that FERC Order No. 561[141] provides the FERC-approved guidance for calculating AFUDC under the uniform system of accounts.[142] Hulbert also testified that as recently as 2007 the FERC has rejected requests (similar to the AG's current proposal) seeking to calculate AFUDC based upon the actual finance costs of the specific funds used to construct a particular project rather than using the general formula under FERC Order No. 561.[143] Hulbert also testified that AEL&P's calculations actually understated the AFUDC slightly since AEL&P had used the correct average interest rate paid on the AIDEA bonds (5.046 percent) but failed to include an amortization of the issuance premiums also paid on the AIDEA bonds.[144]

Through our regulations we have adopted a FERC methodology for calculating AFUDC prescribing the use of a specific formula. It is undisputed that the FERC instructions describe the formula AFUDC amount as a ceiling that a utility may not exceed "without prior approval" of the FERC. The implications of that prior approval requirement need to be addressed before any consideration of the AG's argument that

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[139] It is undisputed that the general AFUDC formula uses the average cost of all debt and the last authorized return on equity. It was also undisputed that in AEL&P's case average cost of debt was 5.30 percent and return on equity was 13 percent.

[140] T-11 (Fairchild) at 28; Tr. 287-288.

[141] Exhibit H-63 (copy of FERC Order No. 561).

[142] Tr. 716-718.

[143] Tr. 717-723.

[144] Tr. 641-644, 734-735.

the discretion to permit AFUDC exceeding the formula[145] amount implies the discretion to order an amount less than that calculated under the formula.

As previously noted AFUDC is calculated annually as an estimate of the costs incurred to finance a multi-year construction project. It is necessarily calculated by the utility outside of the rate setting context in jurisdictions such as ours that do not permit rate recovery of costs before a project is completed and becomes “used and useful” in providing utility service. Having a “pre-approved” method of calculation that a utility is generally bound to use therefore makes sense. Because the calculated AFUDC amounts need to be reviewed and included in annual audited financial statements, it also makes sense that any departure from that generally applicable “pre-approved” method of calculation would need to be approved in advance by the regulator. Otherwise the utility, its auditor, and investors relying upon those audited financial statements could not be certain that the calculations were acceptable to the regulator rather than simply “arithmetically correct.”

The AG’s current proposal raises similar concerns in reverse. Accepting the proposition that we may recalculate AFUDC amounts years later, that possibility would unavoidably reduce the audit process to a math review and introduce an additional degree of regulatory uncertainty. While we received no evidence on the possibility that the utility’s financial statements might need to be re-stated, the imposition of additional regulatory uncertainty in the absence of compelling reasons is not a result we prefer. The AG did not comment upon this aspect of the proposal or why it would be preferable to requiring both the utility (if it seeks a higher than standard

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[145] Since we have adopted their rule the FERC’s interpretations of it are certainly worthy of our consideration though we might not necessarily consider ourselves bound to reach an identical result. Consequently, we appreciated AEL&P’s testimony and submission of orders demonstrating the FERC’s apparent unwillingness to grant requests for approval of AFUDC amounts exceeding those calculated using the formula.

AFUDC amount) and any challenger such as the AG (if it seeks a lower than standard AFUDC amount) to obtain prior approval. For this reason we decline to order recalculation of the otherwise correct AFUDC amounts and reject the AG's proposed AFUDC adjustment to the 2009 revenue requirement study filed by AEL&P. We will include the entire AFUDC amount calculated by AEL&P in its current rate base.[146]

Adjustments for Addition of Lake Dorothy

AEL&P asserts that Lake Dorothy went into commercial service on August 31, 2009.[147] AEL&P is requesting a rate increase based upon its proposed 2009 test year revenue requirement of $43,135,748.[148] This amount includes proposed normalizing adjustments proposed by AEL&P to reflect a full year of Lake Dorothy operations.[149] This also includes an AEL&P proposed normalizing adjustment to rate base so as to account for Lake Dorothy being classified as plant in service for the entire year.[150] AEL&P asserted that these normalization adjustments were justified under the

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[146] Even if we were to review the AFUDC calculations now we would have doubts about the reasonability of the AG's proposal. AEL&P made a $6,771,451 equity investment in the Lake Dorothy project as a pre-condition for obtaining the AIDEA funds. Tr. 178-179; RRS at 3. It had also accumulated an additional $9 million in pre-loan cash to spend on the project in addition to its planned expenditure of $8 million from retained earnings. Exhibit H-36 at 3. The AG's proposed Lake Dorothy AFUDC calculation methodology would seemingly prevent AEL&P from earning a reasonable return on its equity investment in Lake Dorothy during the construction period.

[147] T-5 McLeod Direct at 10; T-7 Hulbert Direct at 7-8; Tr. 55, 91.

[148] RRS at 8.

[149] *See* T-7 Hulbert Direct at 7-8.

[150] RRS at 21 (proposing $41,594,583 increase to 13 month average plant in service).

Commission's decisions in Orders U-01-108(26)[151] and U-08-157(1),[152] because Lake Dorothy would be in operation during the time the rates established in this docket will be in effect.[153]

AEL&P witness Willis testified that energy production from Lake Dorothy was temporarily halted on March 8, 2010, so as to drain Bart Lake and resolve a seepage problem.[154] Energy production was expected to resume on or about July 20, 2010.[155] We authorized an interim and refundable rate increase for AEL&P, effective July 16, 2010.[156]

The AG opposed the Lake Dorothy normalization adjustments, primarily based on an asserted lack of synchronization between these adjustments and the remainder of AEL&P's revenue requirement.[157] In arguing against AEL&P's Lake Dorothy normalization adjustments, the AG distinguished Lake Dorothy from the plant additions at issue in Orders U-01-108(26) and U-08-157(10).[158] The AG particularly

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[151] Order U-01-108(26), *Order Determining Revenue Requirement and Rate Design Issues and Requiring Filings*, dated January 31, 2003 (Order U-01-108(26)).

[152] Order U-08-157(1)/U-08-158(1), *Order Consolidating Dockets, Suspending Tariff Filings, Granting Interim and Refundable Rates, Approving Tariff Sheets, Establishing Interest Rate on Refunds, Requiring Filing, Inviting Participation by the Attorney General, and Intervention, Addressing Timeline for Decision, Scheduling Prehearing Conference, Designating Commission Panel, and Appointing Administrative Law Judge*, dated December 29, 2008. Based upon the context in which this citation is placed, it appears that AEL&P meant to cite to Order U-08-157(10)/U-08-158(10), *Order Resolving Revenue Requirement Issues*, dated February 11, 2010, (Order U-08-157(10)) at 26-28.

[153] T-7 Hulbert Direct at 8.

[154] T-4 Willis Revised Reply at 12; *See* Tr. 91-97.

[155] Tr. 97-98.

[156] Order U-10-29(2) at 11.

[157] *See* T-11 Fairchild Direct at 28-32.

[158] T-11 Fairchild Direct at 30-31.

found significant that Lake Dorothy had been taken out of service from March to July of 2010.[159] The AG also objected on the ground that AEL&P had not removed from its rate base any plant that had been retired during or after the test year.[160] The AG recommended elimination of the proposed Lake Dorothy normalizations, reducing AEL&P's revenue requirement by $5,916,589 and projected revenue by $3,191,898.[161]

AEL&P disputed the AG's interpretation of Orders U-01-108(26) and U-08-157(10).[162] AEL&P witness Willis testified that even with Lake Dorothy power production being off-line for the March to July period, total production for the first twelve-months of operation was 95 percent of the predicted annual output.[163] AEL&P and the AG subsequently stipulated to inclusion of AEL&P's proposed Lake Dorothy operator expense normalization in AEL&P's revenue requirement.[164]

A revenue requirement is supposed to include test year operating revenues and expenses, adjusted to represent a normalized test year.[165] The term "normalized test-year" is defined as: "a historical test-year adjusted to reflect the effect of known and measureable changes and to delete or average the effect of unusual or nonrecurring events, for the purpose of determining a test year which is representative of normal operations in the immediate future."[166]

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[159] T-11 Fairchild direct at 29-31.

[160] T-11 Fairchild Direct at 30, 32.

[161] T-11 Fairchild Direct at 32, JKF-2.

[162] T-8 Hulbert Reply at 19-23.

[163] T-3 Willis Revised Reply at 13.

[164] Stipulation at 3.

[165] 3 AAC 48.275(a)(5), (6), (7), (8).

[166] 3 AAC 48.820(42).

Normalization adjustments have been made to utility revenue requirements in Alaska since at least 1967.[167] Our predecessor, the APUC found in 1980 that:

> The Commission may not, however, confine its analysis simply to the results for 1979. An essential element in establishing permanent rates is the determination of appropriate "normalization adjustments" for "known and measurable changes" which should be made to the results of operations for the test year selected by the Commission, *See, e.g., Re United Gas Pipeline Company*, 54 PUR 3d 285, 291 (FPC 1964).[168]

Regarding new plant in service, ML&P conducted pre-commercial operation testing of its new waste steam generator during the 1983 coincident peak gas usage period on the ENSTAR Natural Gas Company, a Division of SEMCO Energy, Inc. (ENSTAR) system, substantially skewing ENSTAR's cost-of-service study.[169] ENSTAR proposed treating the steam unit as if it were not functional during the test year.[170] The APUC found this proposal to be unreasonable, but also found treating the steam unit as if it had been functional all year was unreasonable.[171] Based upon the evidence available, the APUC ordered a normalization adjustment to ENSTAR's load data to reflect the steam unit being functional 50 percent of the year.[172]

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[167] Order U-66-8(2), *Order Adopting in Part and Modifying in Part the Decision of the Hearing Officer*, dated June 23, 1967, at 3-7.

[168] Order U-80-27(1), *Order Affirming Bench Order*, dated May 9, 1980, at 8.

[169] Order U-83-38(6), *Order Approving Tariff Revision, in Part; Requiring Revisions of Cost of Service Study and Rate Redesign; Approving Sequence of Interruptions; and Establishing Methodology for Allocating Costs Resulting from Interruptions of Service*, dated February 14, 1984 (Order U-83-38(6)), at 7-8.

[170] *See* Order U-83-38(6) at 8-9.

[171] Order U-83-38(6) at 9.

[172] Order U-83-38(6) at 9-10.

In considering normalization adjustments for plant brought into service during or after the revenue requirement test year, we have been concerned about ensuring that adjustments reflecting both the costs and the benefits of the new plant are accounted for, i.e., that the adjustments are synchronized. Synchronization has been defined as:

> The proper matching or balancing of operating expenses (including depreciation and taxes), rate base, and revenue (in this case, revenue is expressed through demand units). The expectation is that the relationships from the test period will hold reasonably constant during the period that rates will be in effect. Any change in those relationships could result in the under-recovery or over-recovery of an approved revenue requirement.[173]

For example, during calendar year 2003 Golden Valley Electric Association, Inc. (GVEA) completed construction of the Northern Intertie Transmission Project from Healy to Fairbanks, and the Battery Energy Storage System (BESS).[174] GVEA filed a revenue requirement study based on a 2003 calendar year test year,[175] and requested a normalization adjustment to annualize depreciation expense for this new plant.[176]

We rejected GVEA's requested normalization adjustment because it was not synchronized with other adjustments that would have been required for the revenue requirement to truly reflect full year operation of the plant.[177] Specifically, GVEA's

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[173] Order U-91-32(1), *Order Opening Dockets; Affirming Hearing and Filing Schedules; and Appointing Hearing Officer*, dated June 24, 1991, Appendix, at 14.

[174] *See* Order U-04-33(10), *Order Granting GVEA Authority to Implement Simplified Rate Filing Procedures; Granting GVEA's Request to Adjust Rates, in Part; Requiring Filing; and Affirming Electronic Rulings*, dated May 31, 2005 (Order U-04-33(10)), at 6-7.

[175] *See* Order U-04-33(10) at 5.

[176] Order U-04-33(10) at 6-7.

[177] Order U-04-33(10) at 7.

proposed adjustment was rejected because it was not synchronized with adjustments for the operations and maintenance expense of the new plant and with adjustments reflecting the benefits of this new plant.[178] A significant reason for rejecting GVEA's proposed depreciation expense normalization adjustment was that GVEA was in the SRF program, and would be filing a new simplified revenue requirement in just six-months that could be based upon actual costs and benefits related to this new plant.[179]

However, in Order U-01-108(26), to which both AEL&P and the AG cited, we allowed normalization adjustments to Chugach's 2000 test year revenue requirement for the Beluga 6 and 7 repowering projects that were not completed until October, 2001.[180] In doing so, we noted that those projects would be operational during the time rates established in that proceeding would be in effect and would result in improved fuel efficiency that would benefit consumers immediately through Chugach's cost of power adjustment (COPA) mechanism.[181] We also noted that the Beluga 6 and 7 normalization adjustments were "exhaustively" reviewed during the rate case litigation,[182] and concluded:

> To reject these adjustments exclusively because they are out-of-period adjustments now would require Chugach to file for rate relief immediately. A lengthy and costly rate proceeding would surely ensue, but the evidentiary record would likely mirror the one just developed in this proceeding.

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[178] Order U-04-33(10) at 7 (Although not specifically identified in the Commission's decision, the Northern Intertie relieved a transmission constraint between Healy and Fairbanks, allowing GVEA to purchase an additional 25 MW of lower cost power from Chugach Electric Association, Inc. (Chugach) or ML&P. BESS allowed GVEA to reduce its spinning reserve requirements by 27 MW. In combination, these two plant additions should have substantially decreased GVEA's fuel cost, but increased purchase power expense, operations expense, and maintenance expense.).

[179] Order U-04-33(10) at 6-7.

[180] Order U-01-108(26) at 59-64.

[181] Order U-01-108(26) at 60.

[182] Order U-01-108(26) at 63-64.

. . . .

> We must balance the difficulty in synchronizing the revenue requirement for Chugach's adjustments for activity beyond the test period with the costs associated (and ultimately borne by ratepayers) with a new revenue requirement filing. In this case, the scales tip in favor of allowing Chugach the out-of-period adjustments.[183]

In Order U-08-157(10), to which both AEL&P and the AG also cite, we allowed AWWU to include a normalization adjustment to its 2007 test year revenue requirement based upon new plant placed into service in October 2007.[184] That normalization was allowed based upon a finding that the plant costs were known and measureable, the plant would be in service during the period of time rates determined in that proceeding would be in effect, and there were no synchronization problems with the benefits of the plant.[185]

Lake Dorothy apparently went into permanent service on or about July 20, 2010, and the interim rate increase authorized in this proceeding could have gone into effect no earlier than July 16, 2010. Thus, for all practical purposes, Lake Dorothy will be in service during the period of time rates established in this proceeding have been or will be in effect. The capital costs of Lake Dorothy are known and measureable and were litigated extensively in this proceeding. The primary operation cost related to Lake Dorothy appears to be labor cost related to the project operator, and the AG has already stipulated to include an annualized normalization adjustment to AEL&P's revenue requirement for this expense. AEL&P is proposing a normalization adjustment to revenue reflecting a full year's worth of anticipated revenue from sales of Lake Dorothy energy to Greens Creek. The other anticipated benefit of Lake Dorothy would be a

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[183] Order U-01-108(26) at 64.

[184] Order U-08-157(10) at 4, 26-28.

[185] Order U-08-157(10) at 28.

reduction in diesel fuel consumption, which will be returned to consumers through AEL&P's COPA mechanism.

There appears to be no material synchronization problem with accepting AEL&P's proposed Lake Dorothy normalization adjustments in this docket. If those adjustments are rejected for being out of time, AEL&P would probably immediately file a new revenue requirement study given the magnitude of the proposed Lake Dorothy adjustments compared to AEL&P's revenue requirement. The public interest would not be served if we were to force AEL&P to immediately file a new rate case. For the reasons stated in Order U-01-108(26) quoted above, we accept AEL&P's proposed Lake Dorothy normalization adjustments. This produces a rate base of $110,661,653 for AEL&P.[186]

Cost of Power Adjustment (COPA)

AEL&P projects selling an average of 66,525,705 kWh of interruptible power per year to Hecla Greens Creek Mining Co. (Greens Creek) pursuant to the Greens Creek Power Sales Agreement (PSA) based on Greens Creek average consumption over the past three years.[187] The current price Greens Creek pays for interruptible power under this special contract is $0.10 per kWh plus a $99.24 per month customer charge.[188] As part of its revenue requirement proposal under consideration here AEL&P has reduced the revenues to be paid by its firm customers by including in base rate calculations an estimated annual revenue from interruptible power sales to

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[186] This figure is arrived by reducing the $112,471,918 pro forma rate base with Lake Dorothy adjustment (H-20, Revenue Requirement Study at 47) by the stipulated rate base adjustment of $1,810,265 (Stipulation at 3-4).

[187] T-7 Hulbert Direct at 5.

[188] T-7 Hulbert Direct at 5.

Greens Creek in the amount of $6,653,761, calculated as [(66,525,705 kWh X $0.10 per kWh) + ($99.24 per month X 12 months)].[189]

However, AEL&P also seeks to protect itself from downward variations in sales to Greens Creek and provide its customers with the benefit of upward variations in sales to Greens Creek.[190] Specifically, AEL&P proposes to adjust its COPA balancing account on a monthly basis by the amount that revenue from sales to Greens Creek are greater or less than $554,480 for that month.[191] This monthly amount is calculated by dividing $6,653,761 by 12.[192] The details of AEL&P's proposal are set forth in the proposed revised Tariff Sheet Nos. 168, 169, 170, and 171, attached to TA381-1 under the heading "Permanent Rates".

The AG has agreed with this proposed treatment of Greens Creek sales revenues.[193] J3P disagrees with this proposal claiming it unreasonably shifts the risk of downward sales variations from AEL&P's owners to AEL&P's firm customers.[194]

The Greens Creek PSA was submitted for our approval in 2005 as TA334-1. It was approved in letter order L0500581. The rate charged for energy delivered to Greens Creek after the Lake Dorothy Project began commercial operation was set at the fully allocated cost of Lake Dorothy Project energy, or $0.10/kWh, whichever was lower.[195] In 2005, AEL&P estimated average sales to Greens Creek would be 60,000,000 kWh/year.[196]

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[189] T-7 Hulbert Direct at 5.

[190] T-7 Hulbert Direct at 5-6.

[191] T-7 Hulbert Direct at 6.

[192] *See* T-7 Hulbert Direct at 6.

[193] T-11 Fairchild Direct at 42-43.

[194] T-13 Sutak Direct at 12-13.

[195] Greens Creek PSA at 34-35.

[196] TA334-1, filed July 5, 2005, at 4.

Pursuant to AEL&P's proposal to adjust its COPA balancing account on a monthly basis, firm ratepayers will make up the difference in months when sales to Greens Creek do not equal the estimated $554,480. Firm ratepayers will enjoy a reduction in rates for months when sales to Greens Creek exceed $554,480.

If we were to reject AEL&P's proposed use of the COPA mechanism, we would also have to remove the normalized Greens Creek revenue from AEL&P's proposed base rates.[197] Removing this normalized revenue would effectively increase the base rates that would be charged to AEL&P's firm customers by increasing AEL&P's revenue deficiency.[198] This increase in base rates would be partially offset if we continued to include a Greens Creek revenue credit in AEL&P's COPA mechanism.

We find that, on an annual basis, AEL&P's proposal results in 100 percent of the Greens Creek revenue being allocated to the benefit of firm customers, and that there is no net shifting of risks. Therefore, we approve inclusion of the Greens Creek revenue element proposed by AEL&P in AEL&P's COPA mechanism.

Return on Equity

AEL&P requested a return on rate base of 10.39 percent.[199] The requested return was based on a capital structure containing 46.2 percent debt and 53.8 percent equity (AEL&P's actual capital structure) and on AEL&P's actual average cost of debt of 5.3 percent. AEL&P proposed a return on equity (ROE) of 14.75 percent based on the testimony of its ROE expert, Zepp.[200] J3P did not address cost of capital issues in its testimony.[201] The AG accepted AEL&P's capital structure and 5.3 percent

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[197] Order U-91-32(1), Appendix at 14.

[198] H-20, Revenue Requirement Study, Schedules 5, 6.

[199] RRS at 8, Schedule 5, Line 5.

[200] RRS at 53, Schedule 12.

[201] T-13 (Sutak).

debt cost as appropriate for setting rates in this proceeding.[202] However, the AG disagreed with AEL&P's requested 14.75 percent ROE and proposed an 11 percent ROE based on the testimony of its expert, Parcell. [203]

Expert Testimony

To determine cost of equity, Zepp used a proxy group of 31 electric utilities. His proxy group is comprised of all utilities listed by AUS Utility Reports in the categories "Electric Companies" and "Combination Electric and Gas Companies" that pay dividends, have investment grade bonds, have at least 51 percent of revenues derived from regulated electric revenues, are not transmission and distribution companies, and have complete and reliable data.[204] The average market capitalization of Zepp's proxy group is $8.5 billion, with the smallest having a capitalization of $700 million and the largest $25 billion.[205]

Parcell chose a proxy group consisting of five publicly-traded electric utilities that have market capitalizations of less than $1 billion and that are engaged in operations similar to AEL&P. Three of the utilities in Parcell's proxy group are part of Zepp's proxy group; two are not.[206] While Parcell's group is comprised of smaller utilities than the average of the Zepp group, the smallest utility in Parcell's sample is still 10 times larger than AEL&P, based on revenues.[207] Parcell performed his ROE analyses on Zepp's proxy group as well as on his own.[208]

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[202] T-12 (Parcell) at 6-7.

[203] T-12 (Parcell) at 36-54.

[204] T-9 (Zepp Direct) at 10-11, TMZ-2 at 1.

[205] T-9 (Zepp Direct), TMZ-2 at 1.

[206] T-12 (Parcell), DCP-2, Schedule 6 at 1.

[207] Tr. 900 (Parcell).

[208] T-12 (Parcell) at 8.

Zepp's recommended ROE of 14.75 percent was based on his estimate of the cost of equity for electric utilities in his proxy group plus a premium to recognize increased risks faced by AEL&P.[209] Zepp found that the cost of equity for his group of publicly-traded electric utilities ranged from 10.8 percent to 11.9 percent based on three discounted cash flow (DCF) analyses and four risk premium analyses, including a capital asset pricing model (CAPM). The results of Zepp's studies were:

Constant Growth DCF Method	11.4%
FERC DCF Method	11.4%
Three-Stage DCF Method	11.1%
First Risk Premium Method	
Five-Year Average	11.5%
Ten-Year Average	11.1%
Second Risk Premium Method	
Original	11.8%
Updated	10.8%
Third Risk Premium Method	11.0%
CAPM	11.0%

Zepp testified that the average result of his DCF analyses, 11.3 percent, provides a reasonable top to his recommended range of equity cost for publicly-traded electric utilities while the average result of his risk premium estimates, 11.2 percent, was a reasonable bottom to the range.[210]

Zepp determined that AEL&P's cost of equity was at least 350 basis points above the cost of common equity of a typical publicly-traded electric utility. He recommended that an average base cost of equity of 11.25 percent (the average of his average DCF estimates and his average risk premium and CAPM estimates) be increased by 3.5 percent to 14.75 percent to recognize AEL&P's greater risks.[211]

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[209] T-9 (Zepp Direct) at 4.

[210] T-9 (Zepp Direct) at 8-9, 27, 30-31; TMZ-2 at 7, 9-10, 12-14.

[211] T-9 (Zepp Direct) at 21-22.

Zepp testified that AEL&P was riskier than the proxy group companies, in part because of its small size. He observed that AEL&P is smaller than any of the utilities in his proxy group and is less than 1 percent as large as the average of the group.[212] He further asserted that AEL&P was more risky than proxy utilities because of its take-or-pay contract for Snettisham power, its lack of interconnection with other electric utilities, its requirement for significant amounts of new capital, its liquidity risk, its limited financing flexibility, its exposure to losses due to avalanches and mud slides, and a perception by investors that Alaska utilities have greater business risks.[213]

The AG, through Parcell, disputed Zepp's analysis. Parcell believed Zepp's explicit risk adjustment of 350 basis points was unwarranted. Further, he testified that each of Zepp's DCF and risk premium methodologies and inputs suffered from defects that had the effect over over-estimating the base cost of equity.[214] In particular, he criticized Zepp for using analysts' forecasts of earnings per share exclusively in his DCF analysis. Parcell believed it improper to use a single measure of growth, especially when it reflected only projected data.[215] Parcell relied on the highest growth rate for his DCF-based ROE recommendation. He explained that, if the highest growth rate had been historical earning per share he would have relied on that. In this case he relied on analysts' forecasts because they were highest but that he would not always propose relying on them.[216]

Parcell criticized Zepp's FERC DCF method as combining two separate DCF types used by the FERC. He recalculated Zepp's FERC DCF using what he

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[212] T-9 (Zepp Direct) at 13.

[213] T-9 (Zepp Direct) at 13-22.

[214] T-12 (Parcell) at 37.

[215] T-12 (Parcell) at 38.

[216] Tr. 901-902 (Parcell).

believes is the DCF model FERC applies to electric utilities. His recalculation results in an estimated cost of equity of 10.1 percent.[217] Parcell also criticized various aspects of Zepp's risk premium analyses.[218] He concluded by asserting that Zepp's ROE estimates significantly exceed recent returns authorized by state regulatory agencies which he claims averaged 10.48 percent in 2009 and 10.34 percent in 2010.[219]

Parcell submitted his own cost of equity analyses—a constant growth DCF (one of the three DCF models used by Zepp), a CAPM analysis, and a comparable earnings analysis (CEM). Each method was applied both to his own five-company proxy group of small publicly traded utilities and to Zepp's 31-company proxy group.[220] Parcell summarized his results[221] in terms of ranges which are:

Proxy Group	DCF	CAPM	CEM
Parcell Group	10.6% to 11.2%	7.7%	Mean 8.5% to 9.9% Median 8.0% to 9.8%
Zepp Group	10.2% to 10.4%	7.7% to 7.8%	Mean 10.4% to 10.9% Median 9.5% to 10.5%

The DCF percentages contained in the chart are based on Parcell's "high" DCF results. He recommended use of his high DCF results in order to recognize the small size of AEL&P.[222] In his constant growth DCF model Parcell used five indicators of growth, including both projected and historical data.[223]

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[217] T-12 (Parcell) at 46.

[218] T-12 (Parcell) at 46-50.

[219] T-12 (Parcell) at 50-51.

[220] T-12 (Parcell) at 8.

[221] T-12 (Parcell) at 25, 29, 31-32.

[222] T-12 (Parcell) at 25.

[223] T-12 (Parcell) at 23-24.

Parcell found an appropriate ROE to be between 10.3 and 11.0 percent based on his constant growth DCF model, between 7.7 and 7.8 based on his CAPM and between 10 and 11 percent based on his CEM. He recommended the high end of those ranges, 11 percent, as the appropriate ROE for AEL&P.[224]

Parcell disagreed with Zepp about the riskiness of AEL&P compared to the electric utilities in Zepp's proxy group. He did not believe AEL&P was riskier because of its take-or-pay Snettisham contract or because of its liquidity risk and limited financing flexibility, as Zepp claimed.[225] Parcell did, however, consider AEL&P somewhat riskier than the proxy companies. He did not choose to recognize that risk by adding an explicit basis-point adjustment to the cost of equity. His ROE recommendation contained an implicit risk adjustment, he testified, because he used the highest growth rates in his DCF analysis and because he recommended the high end (11 percent) of his equity range.[226] Pacell also noted that AEL&P's equity ratio, 53.8 percent, was higher than the equity ratios of the Electric Companies and the Electric and Gas Companies listed by AUS Utility Reports, which ranged from 44 to 48 percent equity in the 2005 to 2009 period.[227]

On reply, Zepp disagreed with many aspects of Parcell's analysis and concluded that Parcell significantly understated the cost of equity of the proxy groups and AEL&P's cost of equity.[228] Zepp contended that Parcell's models should have taken into account our decision in Order U-08-157(10)/U-08-158(10). In particular, Zepp criticized Parcell's constant growth DCF analysis because Parcell included

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[224] T-12 (Parcell) at 35.

[225] T-12 (Parcell) at 51-54.

[226] T-12 (Parcell) at 6, 54.

[227] T-12 (Parcell) at 9-10, 36-54.

[228] T-10 (Zepp Reply) at 4.

historical growth rates in his five indicators of growth rather than relying exclusively on analysts' forecasts.[229] Zepp restated Parcell's results based on his view of the guidance contained in Order U-08-157(10)/U-08-158(10).[230]

Zepp's restatement of Parcell's DCF model estimates a cost of equity of between 11.5 and 11.7 percent for the Parcell proxy group and between 11.2 and 11.4 percent for the Zepp proxy group. When Zepp restated Parcell's CAPM estimate, taking the findings of Order U-08-157(10)/U-08-158(10) into account, the CAPM cost of equity became 9.9 percent for the Parcell proxy group and 10 percent for the Zepp proxy group. Zepp did not attempt to restate Parcell's CEM analysis[231]

Parcell testified that CAPM results have been lower than DCF results in recent years because of current low yields on treasury bonds and the 2008-2009 decline in stock prices. He believes that while the CAPM estimates are lower, DCF results may be somewhat higher due to higher yields attributable to the decline in stock prices. Parcell believes it would be a mistake to entirely ignore CAPM analyses.[232] Zepp testified that, although both he and Parcell reported CAPM results, they gave them minimal weight. When Zepp restated Parcell's DCF and CAPM he weighted the constant growth DCF results 85 percent and the CAPM results 15 percent.[233]

Commission Decision

Although we consider all ROE analyses submitted to us by expert witnesses, in recent cases we have relied most heavily on the constant growth variant of the DCF model and have indicated our preferred ways of calculating it. We continue

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[229] T-10 (Zepp Reply) at 13-24.

[230] T-10 (Zepp Reply) at 4-5.

[231] T-10 (Zepp Reply) at 4-5.

[232] T-12 (Parcell) at 36.

[233] T-10 (Zepp Reply) at 5.

to give the most weight to constant growth DCF analyses in this case. We believe that weighting is appropriate under current economic conditions.

The biggest difference between the two expert witnesses in this case is not the cost of equity they calculate for the proxy companies but the magnitude of the adjustment, whether implicit or explicit, necessary to account for the difference in risk between the proxy groups and AEL&P. Parcell believes AEL&P is somewhat riskier than the utilities in the proxy groups while Zepp believes that AEL&P's risks are greatly (350 basis points) in excess of proxy utilities.

Based on our review of the experts' testimony and all the other evidence in the record concerning the finances and operations of AEL&P, we conclude that AEL&P is riskier than the proxy utilities. However, we decline to accept that recognizing that risk requires an adjustment of 350 basis points. Conversely, we do not believe that adopting the upper end of the range of ROE analyses in this case, without an explicit adjustment, would adequately compensate AEL&P for its greater risk.

Considering all the testimony on the cost of equity for the proxy groups, plus the special risk and risk mitigation factors applicable to AEL&P, we find that an ROE of 12.875 percent most reasonably represents AEL&P's cost of equity. Applying a 12.875 percent ROE to the 53.8 percent equity and combining that result with the application of the undisputed cost of debt of 5.3 percent to the 46.2 percent debt results in an overall weighted cost of capital for AEL&P of 9.375 percent.[234]

Rate Design

After investigation we are required to ensure that rates charged by a utility are just, reasonable and neither unduly discriminatory nor preferential.[235] To aid those

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[234] (12.875% ROE X .538 equity) + (5.3% cost of debt X .462 debt) = 9.375% weighted cost of capital.

[235] AS 42.05.431(a).

determinations we have adopted regulations[236] requiring preparation and submission of a cost-of-service study (COSS) under certain circumstances. Smaller utilities are generally required to submit a COSS only when actively proposing new rate designs. However, in order to more rigorously scrutinize larger electric utilities we require them to submit a COSS in every rate case. AEL&P complied with that requirement (by submitting its COSS and consultant Gray's testimony), though it intended to leave its existing rate design unchanged by implementing its proposed rate increases on an across-the-board basis.[237]

AEL&P's COSS incorporates its proposed rate increases and then compares the revenues expected to be paid by each rate class to the revenues required from each to cover its allocated costs.[238] Two rate classes would pay less than their allocated costs: Residential Rate 10 revenues were estimated to be 2.8 percent less, and Manufacturing Rate 41 revenues were estimated to be 66.5 percent less. Three rate classes would pay more than their allocated costs: Small Commercial Rate 20 revenues were estimated to be 5.7 percent more, Large Commercial Rate 24 revenues were estimated to be 1.7 percent more and Street Light Rate 46 revenues were estimated to be 1.8 percent more.[239] Gray testified that, except for Manufacturing Rate 41 revenues, these results show the proposed across-the-board rate increases yield revenues reasonably equal to the cost of providing service.[240]

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[236] 3 AAC 48.500 – 3 AAC 48.560. The regulation establishes costs as the "fundamental basis" for establishing rates and recognizes the precept that a "cost causer" be "the cost payer" as one primary objective. 3 AAC 48.510(a)(1); 3AAC 48.520.

[237] TA381-1 at 7; T-1 Gray Direct at 9.

[238] The AG agreed that the COSS complied with our regulations. T-11 Fairchild Direct at 37, 40.

[239] COSS at 16; T-1 (Gray Direct) at 11; AEL&P Second Errata, TA381-1 COSS, Page 16, Revised 8-10-2010.

[240] T-1 Gray Direct at 12-13.

Gray testifies that AEL&P currently provides service to only one customer under Manufacturing Rate 41.[241] He further states that AEL&P proposes to resolve this conflict by immediately closing Manufacturing Rate 41 to new customers and (in order to give the customer reasonable notice) terminating this rate class effective January 1, 2012.[242] On that date the customer would begin receiving service under the Large Commercial Rate 24 classification.[243] The change would be implemented through a separate tariff filing.[244]

Fairchild in her testimony on behalf of the AG[245] agrees with AEL&P's proposal to terminate the Manufacturing Rate 41 classification and serve the one customer now receiving service under that rate through the Large Commercial Rate 24 classification.[246] However, the AG makes two additional recommendations. Fairchild recommends we establish a specific 5 percent variance trigger for further evaluating the need for a rate redesign. Fairchild also recommends that we require AEL&P to re-run its COSS to reflect the modified revenue requirement approved in this proceeding and the elimination of the Manufacturing Rate 41 classification.[247] Then, If the re-run COSS indicates a greater than 5 percent deviation between the cost of serving any customer class and the revenues generated by that class, she recommends AEL&P be required to either redesign rates or explain in detail why such difference is just and reasonable.[248]

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[241] T-1 Gray Direct at 8-9.

[242] T-1 Gray Direct at 13.

[243] T-1 Gray Direct at 12.

[244] T-1 Gray Direct at 12.

[245] J3P had no position on these issues.

[246] T-11 Fairchild Direct at 40.

[247] T-11 Fairchild Direct at 40.

[248] T-11 Fairchild Direct) at 41.

In reply Gray agrees generally that AEL&P should always be prepared to explain that its proposed rates are fair and reasonable.[249] However, he disagrees with the proposition that some specific percentage variance should be adopted here to trigger further scrutiny of AEL&P's rate design or any other utility's future rate design. He also disagrees with Fairchild's recommendation of a 5 percent variance trigger stating that a 10 percent variance would be more reasonable.[250]

The variance between the cost of providing service under Manufacturing Rate 41 and its expected revenues appears too great to comply with the requirements of our statute and regulations. However, we do not consider the matter further as AEL&P has proposed to close the class, plans to terminate it in the near future, and the AG agrees with the proposal to provide service through another class with a small variance.

That resolution leaves only one class (Small Commercial Rate 20) with a variance (5.7 percent) exceeding the 5 percent trigger supported by the AG. Neither Gray nor Fairchild referred to any published variance standards for use in determining the propriety of rates. In response to Commissioner questioning at hearing Gray stated he did not know of any such standards.[251] Gray also stated that making changes in rate design is more appropriately done in the context of smaller rate increases rather than the larger rate increases in question here.[252]

In addition both Fairchild and Gray testified that the processes involved in preparing a COSS necessarily involve a degree of imprecision. Fairchild testified that each rate class should produce revenues "reasonably close" to its allocated cost of

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[249] T-2 Gray Reply at 2.

[250] Tr. 309-316.

[251] Tr. 314.

[252] *Id.* at 317-318.

service but requiring an exact match would "inappropriately imply a level of precision that does not exist in the COSS."[253] On cross examination Gray similarly defended his positions by using the example of the "load research" portion of a COSS. He stated a 10 percent variance is accepted in determining that "key factor" in the COSS process.[254]

We begin our analysis by noting that the COSS-related disputes here were quite limited and consequently only a small part of our proceedings. We are therefore not convinced that this docket requires us to adopt a new analytical standard broadly applicable to any future COSS or that the understandably limited record available in this case adequately prepares us to establish a variance standard. This is particularly so in the absence of references to any commonly-accepted standard. While that absence might suggest our record here is incomplete, it might also indicate that other regulators have noted problems with that approach and have declined to adopt a variance standard. We conclude that we should move slowly in considering the adoption of any such standard. We do not adopt the standard proposed by the AG at this time.

Instead, we first conclude that we should approve the termination of Manufacturing Rate 41. At that point only one remaining class (Small Commercial Rate 20) has a variance (seven tenths of a percent) and that variance only slightly exceeds the stringent standard proposed by the AG. We find all the remaining variances demonstrated in the COSS, including Small Commercial Rate 20, demonstrate the reasonably close relationship between allocated costs and expected revenues described by Fairchild. We therefore conclude that AEL&P's proposed rates,

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[253] T-11 Fairchild Direct at 39-40.

[254] Tr. 310 – 312.

implemented by across-the-board rate increases based upon the existing rate design, are just, reasonable, and neither unduly discriminatory nor preferential.

Rates

Based upon our determinations above, we find that AEL&P has a revenue deficiency of $6,727,383.[255] This deficiency could be recovered through a 27.24 percent across-the-board increase to energy and demand charges.[256] However, AEL&P has proposed to forego that portion of its revenue deficiency in excess of the amount that could be recovered through a 24 percent across-the-board increase to energy and demand charges.[257] We approve this proposal and grant AEL&P its requested permanent 24 percent across the board increase to energy and demand charges. We had previously granted AEL&P a 20 percent interim and refundable across the board increase to energy and demand charges in this proceeding.[258] No refund is required, and AEL&P is relieved of the obligation under Order U-10-29(2) to retain funds in an escrow account.

Other Matters

AEL&P filed a copy of its currently applicable credit card processing contract for our approval.[259] We received no comments or testimony objecting to this credit card processing contract. We accept AEL&P's credit card processing contract with Speedpay, Inc., signed March 24, 2004, as amended November 2, 2009, as fulfilling AEL&P's obligations under paragraph 13 of the stipulation approved in Order U-05-90(7).[260]

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[255] *See* Appendix B, attached.

[256] Appendix B.

[257] TA381-1 at 3-4.

[258] Order U-10-29(2) at 11.

[259] TA381-1 at 7, Exhibit 4.

[260] Order U-05-90(7), Appendix at 6.

AEL&P was originally authorized in 1974 to implement a COPA with quarterly rate revisions.[261] Although the record is not entirely clear, it appears that AEL&P was authorized to make COPA rate revisions on a biannual basis as part of the COPA revisions authorized in 1987.[262] In this proceeding, AEL&P requested permission to file quarterly COPA revisions.[263] No party objected to this change, and we approve it.

Tariff Sheets

We approve revised Tariff Sheet Nos. 104, 105, 113, 114, 119, 128, 131, 132, 135, 136, 168, 169, 170, and 171, filed May 3, 2010, with TA381-1 under the cover sheet entitled Permanent Rates, effective the date of this order. Validated copies of the approved tariff sheets will be returned under separate cover.

Final Order

This order constitutes the final decision in this proceeding. This decision may be appealed within thirty days of the date of this order in accordance with AS 22.10.020(d) and the Alaska Rules of Court, Rules of Appellate Procedure (Alaska R. App. P. 602(a)(2)). In addition to the appellate rights afforded by AS 22.10.020(d), a party may file a petition for reconsideration as permitted by 3 AAC 48.105. If such a petition is filed, the time period for filing an appeal is then calculated under Alaska R. App. P. 602(a)(2).

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[261] Order U-74-58(1), *Order Allowing Tariff Revision to go Into Effect Temporarily Pending Investigation and Possible Hearing*, dated June 21, 1974.

[262] *See* Order U-87-57(1), *Order Suspending Permanent Operation of Tariff Filing, Approving Tariff Filing on an Interim Basis, and Requiring Reports*, dated August 5, 1987 (since that date, AEL&P has filed COPA revisions in May and October of each year).

[263] TA381-1 at 9-11.

ORDER

THE COMMISSION FURTHER ORDERS:

1. The *Unopposed Partial Stipulation*, filed April 28, 2011, by Alaska Electric Light and Power Company and the Attorney General is accepted, subject to the express condition that no issue should be considered to have been finally determined or adjudicated by virtue of the stipulation.

2. The request filed by Alaska Electric Light and Power Company in TA381-1 for a 24 percent across-the-board permanent rate increase on energy and demand charges, is approved.

3. The interim and refundable rates established in this docket are made permanent.

4. Tariff Sheet Nos. 104, 105, 113, 114, 119, 128, 131, 132, 135, 136, 168, 169, 170, and 171, filed May 3, 2010, with TA381-1 under the cover sheet titled Permanent Rates, are approved effective the date of this order.

DATED AND EFFECTIVE at Anchorage, Alaska, this 2nd day of September, 2011.

BY DIRECTION OF THE COMMISSION
(Commissioners Kate Giard and Robert M. Pickett,
not participating.)

STATE OF ALASKA

THE REGULATORY COMMISSION OF ALASKA

Before Commissioners:

Stephen McAlpine, Chairman
Rebecca L. Pauli
Robert M. Pickett
Norman Rokeberg
Janis W. Wilson

In the Matter of the Tariff Revision Designated as TA285-4 Filed by ENSTAR NATURAL GAS COMPANY, A DIVISION OF SEMCO ENERGY, INC.	)	U-16-066 ORDER NO. 19

ORDER RESOLVING REVENUE REQUIREMENT AND COST-OF-SERVICE ISSUES AND REQUIRING FILINGS

Table of Contents

BY THE COMMISSION:

Summary

We resolve all revenue requirement and cost-of-service issues raised in TA285-4, filed by ENSTAR Natural Gas Company, a Division of SEMCO Energy, Inc. (ENSTAR). We require ENSTAR to file a revised revenue requirement with supporting schedules, cost-of-service study (COSS), and revised tariff sheets consistent with our decisions in this order as a compliance filing. We allow the other parties the opportunity to file comment on ENSTAR's compliance filing. We require ENSTAR to file a rate case, including a lead-lag study, based on a calendar-year 2020 test year by June 1, 2021.

Background

ENSTAR filed a 2015 test-year rate case as TA285-4.[1] Included with the filing were a revenue requirement study, a COSS, and a lead-lag study. ENSTAR requested a 5.82% interim and refundable across-the-board increase to base rates, effective August 1, 2016, and a permanent rate increase based on the outcome of the COSS and proposed rate design study. ENSTAR proposed a change to its gas cost adjustment (GCA) methodology by adding a line item to the GCA calculation to recover the costs associated with reservation and capacity fees related to stored gas. ENSTAR requested that we approve the new GCA methodology effective October 1, 2016. ENSTAR included tariff sheets reflecting the requested interim and refundable rate increase and the permanent rate increase, and the prefiled direct testimony from Jared B. Green, Robert B. Hevert, John D. Sims, Mark A. Moses, Jillian Fan, Joshua C. Nowak,

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[1] H-1 (TA285-4), filed June 1, 2016.

Daniel M. Dieckgraeff, and Bruce H. Fairchild in support of the tariff filing. We issued public notice of the tariff filing. We received six comments.[2]

We suspended TA285-4 for further investigation, granted the request for an interim and refundable rate increase, approved tariff sheets, invited participation by the Attorney General (AG), and invited petitions for intervention.[3] The AG elected to participate.[4] Titan Alaska LNG, LLC (Titan); Matanuska Electric Association, Inc. (MEA); Homer Electric Association, Inc. and Alaska Electric and Energy Cooperative, Inc. (HEA); Chugach Electric Association, Inc. (Chugach); the Municipality of Anchorage d/b/a Municipal Light & Power Department (ML&P); and JL Properties, Inc. (JL Properties) filed petitions to intervene.[5] We granted the petitions to intervene.[6]

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[2] Comments from J. Pastro, filed June 21, 2016; Comments from B. Richardson, filed June 23, 2016; *Comments of Matanuska Electric Association, Inc. Regarding TA285-4,* filed June 27, 2016; *Tariff Advice No. 285-4; Chugach Electric Association, Inc. Comments on ENSTAR Natural Gas Company / Alaska Pipeline Company General Rate Case Filing,* filed July 5, 2016; *Comments of Homer Electric Association, Inc. and Alaska Electric Energy Cooperative, Inc.,* filed July 5, 2016; *Comments of Municipal Light and Power,* filed July 5, 2016.

[3] Order U-16-066(1), *Order Suspending TA285-4, Granting Request for Interim and Refundable Rate Increase, Establishing Interest Rate on Refunds, Requiring Filing, Approving Tariff Sheets, Scheduling Prehearing Conference, Addressing Timeline for Decision, Inviting Participation by the Attorney General and Intervention, Designating Commission Panel, and Appointing Administrative Law Judge,* dated July 18, 2016.

[4] *Notice of Election to Participate,* filed July 27, 2016.

[5] *Petition to Intervene by Titan Alaska LNG,* filed July 25, 2016; *MEA's Petition to Intervene,* filed July 26, 2016; *Petition for Permission to Intervene of Homer Electric Association, Inc. and Alaska Electric and Energy Cooperative, Inc.,* filed July 27, 2016; *Chugach Electric Association, Inc.'s Petition to Intervene,* filed July 29, 2016; *Municipal Light and Power's Petition to Intervene,* filed August 1, 2016; *Petition to Intervene of JL Properties, Inc.,* filed August 1, 2016.

[6] Order U-16-066(3), *Order Granting Petitions to Intervene,* dated August 12, 2016.

We set a procedural schedule for this docket that included dates to address ENSTAR's request to include gas storage reservation and capacity fees in its GCA.[7] The AG was the only party that filed a response to ENSTAR's request.[8] ENSTAR filed a reply.[9] After further review, the AG filed a non-opposition to ENSTAR's request.[10] We vacated the hearing date set for September 29, 2016, to address ENSTAR's GCA request.[11] We granted ENSTAR's request to include the natural gas storage reservation and capacity fees paid to Cook Inlet Natural Gas Storage Alaska, LLC (CINGSA) as a specific component and cost element of its GCA and weighted average unit cost of gas (WACOG) calculations.[12]

ENSTAR filed a petition for alternative dispute resolution (ADR) procedures including the appointment of a settlement judge.[13] The AG filed an opposition.[14] Chugach

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[7] Order U-16-066(4), *Order Adopting Procedural Schedule, Extending Statutory Timeline with Consent of Parties, and Extending Tariff Suspension Period*, dated August 30, 2016.

[8] *Office of the Attorney General's Response to ENSTAR's Request for Approval of New Methodology for Allocating Certain CINGSA Storage Fees to Its Gas Sales Customers,* filed August 31, 2016.

[9] *ENSTAR Natural Gas Company's Reply to Attorney General's Response to ENSTAR's Request for Approval of New Methodology for Allocating Certain CINGSA Storage Fees to Its Gas Sales Customers,* filed September 7, 2016, and exhibits filed September 8, 2016.

[10] *Office of the Attorney General's Non-opposition to ENSTAR's Request for Approval of New Methodology for Allocating Certain CINGSA Storage Fees to Its Gas Sales Customers,* filed September 19, 2016.

[11] Order U-16-066(5), *Order Vacating September 29 Hearing*, dated September 20, 2016.

[12] Order U-16-066(6), *Order Granting Request for Approval of the Inclusion of Gas Storage Fees in Gas Cost Adjustment*, dated September 27, 2016.

[13] *Petition of ENSTAR Natural Gas Company for Alternative Dispute Resolution Procedures, Including the Appointment of a Settlement Judge,* filed August 12, 2016.

[14] *Opposition to ENSTAR's Petition for Alternative Dispute Resolution Procedures, Including Appointment of Settlement Judge,* filed August 22, 2016.

and ML&P filed non-oppositions.[15] ENSTAR filed a reply.[16] We denied the petition for ADR.[17]

The AG filed a motion for partial summary disposition seeking to remove costs related to Bullet Line development from ENSTAR's revenue requirement.[18] ENSTAR filed an opposition to the AG's motion.[19] JL Properties and HEA each filed a statement in support of the AG's motion.[20] The AG filed a reply.[21] We granted the AG's motion for partial summary disposition and required ENSTAR to remove $465,786 in Bullet Line development amortization expenses from its revenue requirement.[22]

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[15] *Chugach Electric Association, Inc.'s Non-opposition to Petition of ENSTAR for Alternative Dispute Resolution,* filed August 22, 2016; *Municipal Light and Power's Nonopposition to Petition for Alternative Dispute Resolution Procedures,* filed August 22, 2016.

[16] *ENSTAR Natural Gas Company's Reply to AG-RAPA's Opposition to Petition for Alternative Dispute Resolution Procedures, Including Appointment of a Settlement Judge,* filed August 25, 2016.

[17] Order U-16-066(9), *Order Granting Motion to Strike and Denying Petition for Alternative Dispute Resolution*, dated November 4, 2016.

[18] *Office of the Attorney General's Motion for Partial Summary Disposition Re: Bullet Line Costs*, filed April 7, 2017.

[19] *ENSTAR's Opposition to the Attorney General's Motion for Partial Summary Disposition Re: Bullet Line Costs*, filed April 17, 2017.

[20] *JL Properties, Inc.'s Statement in Support of the Office of the Attorney General's Motion for Partial Summary Disposition Re: Bullet Line Costs*, filed April 21, 2017; *Homer Electric Association Inc. and Alaska Electric Energy Cooperative Inc.'s Statement in Support of RAPA's Motion for Partial Summary Disposition Re: Bullet Line Costs*, filed April 24, 2017.

[21] *Office of the Attorney General's Reply to ENSTAR's Opposition to Motion for Partial Summary Disposition Re: Bullet Line Costs*, filed April 20, 2017.

[22] Order U-16-066(15), *Order Granting Motion for Partial Summary Disposition*, dated May 31, 2017.

HEA filed a motion to strike portions of ENSTAR's reply testimony.[23] MEA joined HEA's motion.[24] ENSTAR filed a response to HEA's motion to strike.[25] MEA filed a reply to ENSTAR's response.[26] We denied the motion to strike.[27]

We held a public hearing that began on June 2, 2017, and continued through June 23, 2017.[28] ENSTAR,[29] the AG,[30] Titan,[31] MEA,[32] HEA,[33] Chugach,[34] ML&P,[35] and JL Properties[36] filed post-hearing briefs.

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[23] *Homer Electric Association Inc. and Alaska Electric Energy Cooperative Inc.'s Motion to Strike ENSTAR Natural Gas Company Testimony,* filed April 24, 2017.

[24] *Matanuska Electric Association, Inc.'s Joinder in Homer Electric Association Inc.'s Motion to Strike ENSTAR Natural Gas Company's Testimony,* filed April 28, 2017.

[25] *ENSTAR Natural Gas Company's Response to Homer Electric Association Inc.'s and Alaska Electric and Energy Cooperative Inc.'s Motion to Strike,* filed May 8, 2017.

[26] *Matanuska Electric Association, Inc.'s Reply to ENSTAR Natural Gas Company's Response* [sic] *to Homer Electric Association Inc.'s Motion to Strike,* filed May 11, 2017.

[27] Tr. 46.

[28] Tr. 38-3320.

[29] *ENSTAR Natural Gas Company's and Alaska Pipeline Company's Post-Hearing Brief,* filed July 21, 2017 (ENSTAR Post-hearing Brief).

[30] *Office of the Attorney General's Post-Hearing Brief,* filed July 21, 2017; *Errata to Post-Hearing Brief of Chugach Electric Association, Inc.,* filed August 1, 2017; *Corrected Post-Hearing Brief of Chugach Electric Association, Inc.,* filed August 1, 2017 (AG Post-Hearing Brief).

[31] *Titan's Post-Hearing Brief,* filed July 21, 2017 (Titan Post-Hearing Brief).

[32] *Matanuska Electric Association, Inc.'s Closing Brief,* filed July 21, 2017 (MEA Closing Brief).

[33] *Homer Electric Association, Inc. and Alaska Electric Energy Cooperative, Inc.'s Post Hearing Brief,* filed July 21, 2017 (HEA Post-Hearing Brief).

[34] *Post-Hearing Brief of Chugach Electric Association, Inc.,* filed July 21, 2017, as corrected by *Errata to Post-Hearing Brief of Chugach Electric Association, Inc.,* filed August 1, 2017 (Chugach Post-Hearing Brief).

[35] *Municipal Light and Power's Post-Hearing Brief,* filed July 21, 2017 (ML&P Post-Hearing Brief).

[36] *Post-Hearing Brief of JL Properties, Inc.,* filed July 21, 2017, as corrected by *JL Properties, Inc.'s Errata to Its Post-hearing Brief,* filed July 27, 2017 (JL Properties Post-Hearing Brief).

Discussion

ENSTAR is a natural gas distribution utility and holds Certificate of Public Convenience and Necessity No. 4 issued by this commission. Alaska Pipeline Company (APLC) is a natural gas transmission utility and holds Certificate of Public Convenience and Necessity No. 141. The two entities are affiliates. ENSTAR is a division of SEMCO Energy, Inc. (SEMCO), while APLC is a subsidiary of SEMCO. The rates and terms of service for both utilities are found in a common tariff issued in ENSTAR's name. "ENSTAR" as used in this order refers to both entities, unless explicitly stated or the context clearly indicates otherwise. ENSTAR is an integrated, hybrid system, with both natural gas transmission and distribution assets.[37]

Approximately 99% of ENSTAR's customer base (by customer count) consists of residential and small commercial customers. The remainder of ENSTAR's customer base consists of commercial and industrial customers. ENSTAR's transportation customers include other public utilities, such as intervenors MEA, HEA, Chugach, and ML&P. ENSTAR purchases approximately 33 billion cubic feet of natural gas annually from various Cook Inlet producers for delivery through its transmission and distribution systems to residential, commercial, and industrial customers.[38]

ENSTAR's transmission assets transport gas, some of which has been procured by ENSTAR for resale and some by third parties for their own consumption, from supply areas to large customers, such as power generation facilities, and to the ENSTAR distribution system. The transmission system is made up of approximately 284 miles of 12-inch to 20-inch diameter pipeline and approximately 107 miles of smaller diameter pipeline. The transmission system consists primarily of two pipeline systems that extend from natural gas fields on both sides of Cook Inlet into the Anchorage area.

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[37] T-1, *Prefiled Direct Testimony of Jared B. Green* at 12.

[38] T-14, *Prefiled Testimony of Janet K. Fairchild-Hamilton* at 8.

The Kenai Pipeline System serves the east side of Cook Inlet and enters Anchorage from the south through the Potter Gate Station. The Beluga Pipeline System serves the west side of Cook Inlet and enters Anchorage from the north near ML&P Plant 2. The two systems are interconnected in Anchorage, allowing the distribution system to serve customers using gas supplied through either system. The origination points of the two pipeline systems are interconnected by a producer-owned pipeline, creating a full loop of the transmission system.[39] Transmission plant is approximately 40% of ENSTAR's total plant.[40] On a percentage use basis, third-party transportation accounts for nearly half of ENSTAR system volumes.[41]

Distribution assets deliver gas to smaller end-users such as homes, schools, and hospitals.[42] ENSTAR distributes natural gas through a network of approximately 3,000 miles of distribution pipeline, with 126,000 service lines connecting to approximately 141,000 residential, commercial, and industrial customers in the Cook Inlet area.[43] The cities and areas served include Anchorage, Anchor Point, Big Lake, Bird Creek, Butte, Eagle River, Girdwood, Homer, Houston, Indian, Kasilof, Kenai, Knik, Palmer, Nikiski, Nikolaevsk, Soldotna, Wasilla, and Whittier.[44]

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[39] T-1 (Green Direct) at 12.

[40] T-12, *Prefiled Direct Testimony of Robert B. Hevert* at 10; T-13, *Prefiled Reply Testimony of Robert B. Hevert* at 23 n.39; T-2, *Prefiled Reply Testimony of Jared B. Green* at 25.

[41] *See, e.g.* H-67.

[42] T-1 (Green Direct) at 12.

[43] T-1 (Green Direct) at 15; T-14 (Fairchild-Hamilton) at 8.

[44] T-1 (Green Direct) at 15.

During this proceeding it was undisputed that ENSTAR operates a safe and reliable utility whose cost to distribute gas to its customers is well below the average cost nationwide.[45]

Statutory Requirement to Ensure Just and Reasonable Rates

We are charged by statute to ensure that the rates charged by ENSTAR are just and reasonable.[46] To determine just and reasonable rates we review a utility's proposed total annual required earnings, known as the revenue requirement. At a high level, the revenue requirement is the sum of the utility's legitimate expenses, plus annual depreciation, plus a fair return on investment.[47] To determine the revenue requirement we utilize a normalized test year defined as a "historical test-year adjusted to reflect the effect of known and measurable changes and to delete or average the effect of unusual or nonrecurring events, for the purpose of determining a test year which is representative of normal operations in the immediate future."[48] "[T]he ratemaking process is not designed to ensure that a utility recover a specific expense which it has incurred."[49] Rather, "the process is designed to allow the utility an opportunity to recover costs which the utility can be expected to incur in the future, and the test year [is] examined to determine what that level of costs is likely to be."[50] In the current proceeding, ENSTAR

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[45] *See* T-1 (Green Direct) at 16-18.

[46] AS 42.05.381(a).

[47] *See* Order U-81-032(3), *Order Granting Rate Increase and Approving Rate Redesign,* dated November 20, 1981, at 3.

[48] 3 AAC 48.820(42).

[49] Order U-87-084(8), *Order Deciding Revenue Requirement Issues and Requiring Filings,* dated September 7, 1988, at 13.

[50] Order U-87-084(8) at 13-14.

utilized a 2015 test year with proposed adjustments intended to represent the rate-effective period.[51]

Once the revenue requirement has been determined, we review the COSS which allocates the revenue requirement among customer classes. The results of the COSS are used as the basis to develop rates for the customer classes.[52]

Decisions are Based on the Record as a Whole

Our decisions in this docket are based on the record as a whole. In the interests of administrative efficiency, we have chosen not to directly address every argument raised in this matter. Arguments not affirmatively addressed are to be considered denied based on the totality of the record. Proposals in TA285-4 that were not disputed or otherwise addressed in this order are approved.[53]

Hearing Testimony

ENSTAR

ENSTAR presented testimony from Jared Green, Mark Moses, Jillian Fan, Timothy Lyons, John Sims, Bruce Fairchild, Daniel Dieckgraeff, and Robert Hevert.

Jared Green

Green was the President of ENSTAR at the time he presented testimony and during the 2015 test year. Green presented a general overview of the rate filing and was presented as the lead policy witness for ENSTAR.[54]

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[51] H-1 (TA285-4) at 5.

[52] *See* Order U-81-044(5), *Order Affirming Bench Order Granting Permanent Rate Increase and Further Extending Suspension Period Concerning Rate Redesign,* dated August 2, 1982, as corrected by *Errata Notice*, dated August 9, 1982, at 3.

[53] *E.g.*, Non-disputed SEMCO and AltaGas Ltd. allocated costs; depreciation rates.

[54] T-1 (Green Direct); T-2 (Green Reply). Green transferred as President to AltaGas Canadian Utilities in August 2017.

Mark Moses

Moses is the Vice President, Chief Financial Officer, and Treasurer of SEMCO. Moses presented testimony describing: the legal structure of SEMCO and its relationship to ENSTAR; shared services and charges for those services provided by SEMCO to ENSTAR; the methodology for allocating costs from AltaGas Ltd. (AltaGas)[55] and its intermediate holding company to SEMCO for services provided for ENSTAR; and the treatment for ratemaking purposes of net deferred tax assets and liabilities that resulted from the acquisition of ENSTAR by SEMCO in 1999.[56]

Jillian Fan

Fan is the Director, Regulatory Policy for AltaGas. Fan addressed the relationship between AltaGas and ENSTAR, described corporate support services provided by AltaGas to ENSTAR, and explained how ENSTAR is charged for these services.[57]

Timothy Lyons

Lyons is a partner at the consulting firm of ScottMadden, Inc. Lyons presented the lead-lag study that forms the basis for the cash working capital allowance included in ENSTAR's rate base.[58]

John Sims

Sims was the Vice President of Corporate Resources and Business Development of ENSTAR and CINGSA at the time he presented testimony and during the test year. Sims described the necessity of the services that ENSTAR receives from

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[55] ENSTAR's indirect parent company.

[56] T-3, *Prefiled Direct Testimony of Mark A. Moses*.

[57] T-4, *Prefiled Direct Testimony of Jillian Fan.*

[58] T-5, *Prefiled Direct Testimony of Joshua C. Nowak as Adopted by Timothy S. Lyons*.

SEMCO and AltaGas in its day-to-day operations and the benefits to customers of those services. Sims also addressed ENSTAR's compensation and credit card processing expenses, and some SEMCO allocated costs to ENSTAR.[59]

Bruce Fairchild

Fairchild is a principal in the consulting firm Financial Concepts and Applications, Inc. Fairchild presented the schedules that make up ENSTAR's revenue requirement and sponsored adjustments to test year data. Fairchild also presented ENSTAR's COSS and developed rates for ENSTAR's proposed customer classes.[60]

Daniel Dieckgraeff

Dieckgraeff is the Director of Rates and Regulatory Affairs for ENSTAR. Dieckgraeff sponsored various schedules supporting the revenue requirement and described several adjustments to test year data. Dieckgraeff also addressed aspects of the COSS and rate design. Dieckgraeff presented the change to ENSTAR's GCA provision related to stored gas costs which we approved in Order U-16-066(6).[61]

Robert Hevert

Hevert is Managing Partner of Sussex Economic Advisors, LLC. Hevert addressed the proposed return on equity (ROE), capital structure, and cost of debt for ENSTAR.[62]

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[59] T-6, *Prefiled Direct Testimony of John D. Sims*; T-7, *Prefiled Reply Testimony of John D. Sims*. Sims was promoted to President of ENSTAR in August 2017.

[60] T-8, *Prefiled Direct Testimony of Bruce H. Fairchild*; T-9, *Prefiled Reply Testimony of Bruce H. Fairchild*.

[61] T-10, *Prefiled Direct Testimony of Daniel M. Dieckgraeff*; T-11, *Prefiled Reply Testimony of Daniel M. Dieckgraeff*.

[62] T-12 (Hevert Direct); T-13 (Hevert Reply).

AG

The AG presented testimony from Janet Fairchild-Hamilton, Ralph Smith, and David Parcell.

Janet Fairchild-Hamilton

Fairchild-Hamilton is a Public Advocate Utility Analyst for the AG. Fairchild-Hamilton addressed the revenue requirement proposed by ENSTAR and proposed numerous modifications.[63]

Ralph Smith

Smith is a Senior Regulatory Consultant at Larkin & Associates, PLLC. Smith addressed ENSTAR's proposed revenue requirement, COSS, and rate design.[64]

David Parcell

Parcell is Principal and Senior Economist of Technical Associates, Inc. Parcell addressed the current cost of capital for ENSTAR.[65]

Titan

Titan presented testimony from Dan Britton and Ronald Cliff.

Dan Britton

Britton is the President of Titan. Britton addressed the service provided to Titan, alleged misallocations in ENSTAR's COSS, and several rate calculation issues.[66]

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[63] T-14 (Fairchild-Hamilton).

[64] T-15, *Prefiled Testimony of Ralph C. Smith*.

[65] T-16, *Prefiled Testimony of David C. Parcell*.

[66] T-17, *Prefiled Testimony of Dan Britton*.

Ronald Cliff

Cliff is the President of Highcliff Energy Services Ltd. Cliff addressed the allocations by ENSTAR to Titan's cost-of-service and the rate proposed for Titan. Cliff proposed a Titan specific cost allocation and rate.[67]

MEA

MEA presented testimony from Anthony Izzo, James Wilson, and Daniel Lawton.

Anthony Izzo

Izzo is the General Manager for MEA. Izzo testified as the MEA company witness in this docket. Izzo addressed: a description of MEA; MEA's Eklutna Generation Station (EGS) dual fuel generation capability; MEA's Very Large Firm Transportation (VLFT) service agreement with ENSTAR; MEA's gas supply agreements with Hilcorp Alaska, LLC (Hilcorp); MEA as a VLFT customer; transport service quality and firmness of MEA's transport service; power and fuel pooling, and the proposed Anchorage Pool Firm Transportation (APFT) service tariff; and separation of ENSTAR's transportation, distribution and gas supply or storage services.[68]

James Wilson

Wilson is an economist and independent consultant doing business as Wilson Energy Economics. Wilson addressed the transportation services and rates available to MEA as proposed by ENSTAR and presented alternative recommendations.[69]

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[67] T-18, *Prefiled Testimony of Ronald Cliff*.

[68] T-19, *Testimony of Anthony M. Izzo*.

[69] T-20, *Testimony of James F. Wilson*.

Daniel Lawton

Lawton is a consultant and presented testimony as an economist. Lawton addressed ENSTAR's overall rate increase request, proposed revenue requirement, cost allocation, and rate design.[70]

HEA

HEA presented testimony from Mikel Salzetti.

Mikel Salzetti

Salzetti is the Manager of Fuel Supply and Renewable Energy Development at HEA. Salzetti provided a brief overview of HEA's power generation portfolio and the services HEA receives from ENSTAR under its tariff. Salzetti presented testimony advocating that we: disallow recovery of the costs of the CINGSA Bypass Lateral or establish a means of recovering those costs outside of ENSTAR's postage stamp rate; require ENSTAR to allocate all costs of the South Peninsula Pipeline and all costs of the Credit Card Program to ENSTAR's distribution customers; require ENSTAR to calculate the Titan/HEA Meter Weight Factor in the same manner as all other Meter Weight Factors; require ENSTAR to include volumes for economy energy sales gas in its revenue adjustments; eliminate the use of gradualism in this rate case and instead require ENSTAR to use its actual cost of service study results to determine its rates; and give particular scrutiny to ENSTAR's proposed ROE of 12.55%.[71]

Chugach

Chugach presented testimony from Carl Peterson and Arthur Miller.

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[70] T-21, *Testimony of Daniel J. Lawton*.

[71] T-22, *Prefiled Testimony of Mikel Salzetti*.

Carl Peterson

Peterson is an Academic Affiliate of NERA Economic Consulting and a faculty member at the University of Illinois Springfield. Peterson presented testimony advocating against ENSTAR's use of the Seaboard method to allocate transmission mains and expenses and in favor of the peak-day allocation factor.[72]

Arthur Miller

Miller is the Executive Manager, Regulatory and External Affairs for Chugach. Miller addressed ENSTAR's COSS and the use of the Seaboard method to allocate transmission-related expenses. Miller presented testimony supporting ENSTAR's use of postage stamp rates and development of the APFT rate schedule.[73]

ML&P

ML&P presented testimony from James Daniel.

James Daniel

Daniel is a Vice President at the firm GDS associates, Inc. Daniel addressed ENSTAR's COSS, ML&P's inclusion in the VLFT rate schedule, and the proposed APFT rate schedule.[74]

JL Properties

JL Properties did not present a witness. JL Properties engaged in cross-examination of the other parties' witnesses.

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[72] T-23, *Prefiled Responsive Testimony of Carl R. Peterson, PhD on Behalf of Chugach Electric Association, Inc*.

[73] T-24, *Prefiled Responsive Testimony of Arthur W. Miller on Behalf of Chugach Electric Association, Inc.*

[74] T-25, *Prefiled Responsive Testimony of James W. Daniel*.

Revenue Requirement Issues

We address the disputed revenue requirement issues as follows.

Rate Base

13-Month Average vs. Year-End Rate Base

Our regulations require a utility to file its computation of rate base using a 13-month average. Thirteen-month average is "the arithmetic sum of the beginning of each month net balance for the 12-month test period, plus the balance at the end of the twelfth month of the test period, divided by 13." A utility is also allowed to propose, and file, using "any other rate-base theory" that it considers appropriate and supportable.[75]

In this proceeding, ENSTAR proposes the use of test year-end rate base.[76] ENSTAR argues that use of a 13-month average understates the current value of plant in service while test year-end rate base represents "the actual capital invested by ENSTAR to serve customers at the end of 2015."[77] ENSTAR acknowledges that we have the authority to set rates using either the proposed year-end rate base or 13-month average rate base.[78]

ENSTAR argued that we have allowed the use of year-end rate base in other proceedings after considering "all relevant factors."[79] ENSTAR asserted that test year-end rate base is more representative of the future period for which rates are being

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[75] 3 AAC 48.275(a)(9).

[76] H-1 (TA285-4) at 8; T-10 (Dieckgraeff Direct) at 14-22; T-11 (Dieckgraeff Reply) at 6-19; T-1 (Green Direct) at 29-31; T-2 (Green Reply) at 6-10; T-9 (Fairchild Reply) at 4-16.

[77] H-1 (TA285-4) at 8.

[78] ENSTAR Post-Hearing Brief at 11.

[79] T-11 (Dieckgraeff Reply) at 9-11 (citing Order U-05-043(15)/U-05-044(15), *Order Establishing Revenue Requirement, Ordering Refunds, and Requiring Filings,* dated January 8, 2007 (Order U-05-043(15)/U-05-044(15)), at 38).

set, particularly when the utility has made significant capital expenditures as has ENSTAR.[80] ENSTAR argued that its $40.7 million test year investment in plant during the test year: represented a significant plant investment, among the highest in ENSTAR's history; represented an abnormal amount and type of investment, the vast majority of which is non-revenue-producing; updated and maintained aging infrastructure and involved major system repairs; was made during challenging economic conditions; and came amid declining customer usage. ENSTAR claimed that these are relevant factors that support its request for test year-end rate base.[81]

ENSTAR presented testimony that it had $40.7 million in capital expenditures in 2015, all of which was used and useful in providing service during the test year. ENSTAR stated that $34.6 million of the expenditures were for non-income producing plant.[82]

ENSTAR asserted that significant capital expenditures were required to comply with federally mandated transmission pipeline integrity management, distribution pipeline integrity management, and pipeline maximum allowable operating pressure testing programs. ENSTAR stated that $3.2 million in investment to install facilities necessary to "pig" its two Turnagain Arm crossings ($2.3 million at Potter Gate Station and $.9 million at Burnt Island) were a part of the programs.[83] The facilities at Potter Gate and Burnt Island allow the lines to be internally inspected for corrosion, degradation of wall thickness, or other potential risks via inline smart pipeline inspection gauges, or

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[80] T-10 (Dieckgraeff Direct) at 15.

[81] ENSTAR Post-Hearing Brief at 13.

[82] T-10 (Dieckgraeff Direct) at 17.

[83] T-10 (Dieckgraeff Direct) at 18.

"pigs."[84] ENSTAR states that the 13-month average rate base calculation will result in the inclusion of only $246,000 of the $3.2 million investment in rate base.[85] This results in non-recovery of operating and capital costs on the difference of $2.952 million.[86]

During the test year, ENSTAR engaged in a $2.5 million emergency replacement of part of the 20-inch Beluga-to-Anchorage pipeline at the Beluga River crossing after the river bank receded and exposed the original line.[87] ENSTAR also spent $4.7 million to replace over 50,000 Encoder Receiver Transmitters (ERTs), a packet radio protocol used for automatic meter reading that had reached the end of their 15-year battery design lives. The ERTs allow ENSTAR to use vehicle-mounted equipment to read meters by driving through neighborhoods and receiving signals from the meters without the need to physically visit and visually read each meter, ultimately lowering costs.[88]

In its request for year-end rate base, ENSTAR continued to use 13-month average rate base for Materials and Supplies, Prepayments, and Gas Stored Underground.[89]

The AG argued in favor of using a 13-month average rate base, rather than ENSTAR's proposed year-end rate base.[90] The AG states that the proposal to use year-end rate base operates to increase ENSTAR's revenue requirement by $2.9 million.[91]

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[84] T-1 (Green Direct) at 22.

[85] T-2 (Green Reply) at 9.

[86] T-9 (Fairchild Reply) at 5-7.

[87] T-10 (Dieckgraeff Direct) at 18.

[88] T-10 (Dieckgraeff Direct) at 20.

[89] T-10 (Dieckgraeff Direct) at 22.

[90] T-14 (Fairchild-Hamilton) at 13-26.

[91] T-14 (Fairchild-Hamilton) at 13-14.

The AG states that ENSTAR's plant in service increased by $31.7 million during the test year.[92] The AG asserts that the difference between the $31.7 million increase in plant in service and the $40.7 million[93] investment referenced in ENSTAR's prefiled testimony appears to be due to plant retirement or investment in plant not in service by test-year end. The AG calculated the percent change in net plant for ENSTAR during the test year by comparing plant in service and accumulated depreciation at January 1, 2015, and December 31, 2015. The calculation demonstrates a 10.15% increase in net plant during the test year.[94] The AG also calculated a 1.4% growth in customers for ENSTAR during the test year.[95]

JL Properties did not present testimony, but argued in favor of 13-month average rate base.[96]

MEA argues against the use of year-end rate base and in favor of a 13-month average rate base. MEA states that use of 13-month average will reduce ENSTAR's revenue requirement by roughly $2.9 million per year.[97]

A review of our past decisions regarding the use of year-end rate base was provided in Order U-07-076(8)/U-07-077(8):

> The historical standard for determining whether year-end rate base treatment is appropriate was established in Order U-75-30(4), where the commission determined a year-end rate base may be substituted for the commission's preferred average-year rate base only when a utility can document extraordinary growth in both plant and customers. In that docket, we stated,
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> 'The year-end rate base concept is best applied in an atmosphere where the utility is experiencing extraordinary high growth in plant and customers and the

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[92] T-14 (Fairchild-Hamilton) at 20.

[93] T-10 (Dieckgraeff Direct) at 17.

[94] T-14 (Fairchild-Hamilton) at 20-21. The values are found in H-1 (TA285-4), Attachment B at Schedule N and Attachment C at Schedule N.

[95] T-14 (Fairchild-Hamilton) at 24.

[96] JL Properties Post-Hearing Brief at 24-25.

[97] T-21 (Lawton) at 21-27.

utility has made a clear showing that it is endeavoring to cope with needs for their services due to abnormal population and economic growth conditions within its service area. If a utility is experiencing extraordinary growth and demand for its services, it will find it necessary to increase its rate base considerably each year. If this is projected to happen or has a history that it will happen then the Commission by adopting the year-end rate base will not be unreasonably allowing the utility to charge a rate calculated on a revenue requirement that has not fully assessed the revenues that may be derived from a portion of the rate base.'

The standard was expanded in Docket U-76-70, allowing the use of a year-end rate base because of declining revenues and a depressed economy.

'The Commission has found the use of the year-end rate base appropriate when a utility is experiencing extraordinary growth and demand for its services. It is reasonable that when opposite conditions exist, e.g. an extraordinary decrease in demand as a result of a negative economic climate which results in substantially less revenues to a utility, that a year-end rate base should be used.'

The issue was also addressed in Order U-81-44(5). In that order, the commission further expanded the criteria to include sales growth compared to revenue growth, rather than a strict reliance on customer growth. The commission also modified the formula for determining growth in net plant by comparing the percent difference between a calculation using year-end rate base and a calculation using the 13-month average rate base, allowing year-end plant accounts because the utility's computation of year-end rate base was 28 percent more than using the 13-month average rate base. The commission noted:

'The commission is concerned that in other recently decided cases, e.g., U-81-32(3), the commission may have applied the above standard more rigorously than in the instant proceeding. Staff did not specifically examine this aspect of the utility's rate relief request. The utility's filing also shows that kilowatt-hour (KWH) sales were growing at a rate of 14 percent a year, and revenue at the rate of 10.6 percent a year; thus, sales were growing more rapidly than revenue. The Commission will allow the use of a year-end rate base for AEL&P in this proceeding. In prior cases the Commission has found use of year-end rate base appropriate when a utility is experiencing extraordinary growth and demand for its services. It is apparent that such is the case here.'

In Order U-05-043(15)/U-05-044(15), we stated,

'In reviewing the proposed use of a year-end rate base, we consider all relevant factors. These utilities required major capital investment to rebuild or replace their worn out plant. We recognized this and provided unique regulatory treatment since acquisition from the previous owner. During the test year, the utilities demonstrated growth in combined rate base of almost 21 percent, reflecting the continuation of the facilities improvement program. The capital investment was to rebuild or replace worn out plant and did not result in nor was it intended to significantly increase customer connections. No party

> suggested the rate base improvements were not needed to provide safe reliable utility services. During the test year the utilities did not experience increases in the number of customers or in revenues that would offset the dramatic increase in investment. Under all of the above circumstances and for this rate case we find use of year-end rate base is reasonable.'
>
> Thus, in this decision, we further modified the historical precedent, which required an abnormal change in net plant plus extraordinary swings in customers or revenues, acknowledging that GHU/CUC's lack of customer growth would provide little revenue to offset its substantial investment in plant. A critical factor, however, which GHU/CUC do not recognize in their testimony, is that we maintained that same concept that has flowed through all of the previous decisions. That is, the first step of the analysis has always been an evaluation and conclusion that the change in net plant is abnormal. Only after this threshold test is met do the other operational factors, such as customer loss, lack of customer growth, or sales versus revenues, weigh in the equation to determine if the use of the year-end rate base is appropriate."[98]

These past decisions establish that the 13-month average is our preferred method for calculating rate base. A utility must demonstrate that an exception is warranted before we will allow the use of year-end rate base. Our historical precedent required an extraordinary increase in plant and customers or an extraordinary decrease in demand and substantial decrease in revenue. In decisions specific to the circumstances faced by Golden Heart Utilities, Inc. and College Utilities Corporation (GHU/CUC) we identified other relevant factors.[99] However, even in those dockets, and consistent with historic precedent, we required a threshold determination that the utility's change in net plant during the test year was extraordinary.

The evidence establishes that ENSTAR invested $40.7 million during the test year, that ENSTAR's change in net plant during the test year was $31.7 million, that the percent change in net plant for the test year was an increase of 10.15%, and that

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[98] Order U-07-076(8)/U-07-077(8), *Order Establishing Revenue Requirement, Ordering Refunds, and Requiring Filings,* dated June 30, 2008, at 37-39 (internal citations omitted).

[99] In Order U-06-138(4)/U-06-139(4) at 18-19, we stated that the decision to allow year-end rate base for GHU/CUC was limited the unique circumstances presented. We reaffirmed the requirement for extraordinary growth in both customers and plant, or any extraordinary growth (or decrease) in demand for services.

ENSTAR experienced a 1.4% increase in its customer base during the test year. This evidence does not establish that ENSTAR is experiencing an extraordinary increase in plant combined with an extraordinary increase in customers. Nor does the evidence establish that ENSTAR is experiencing an extraordinary decrease in demand combined with a substantial decrease in revenue. Even if we were to find that the GHU/CUC precedent was applicable to the circumstances faced by ENSTAR, a 10.15% increase in net plant is not extraordinary as required by our precedent. We deny ENSTAR's request for year-end rate base.

Annualize Adjustment for New Plant

As part of its argument regarding year-end rate base, ENSTAR asserted that we have allowed "post-test-year additions to plant" when the plant will be used and useful in providing utility service during the period the prospective rates will be in effect and the plant amount is known and measurable.[100] ENSTAR claimed that its year-end plant meets these requirements.[101]

As a preliminary matter Order U-10-029(15) and Order U-08-157(10) cited by ENSTAR did not address post-test-year additions to plant. The orders addressed annualizing adjustments for plant placed in service during the test year. We explained the rationale for our decisions in Order U-10-029(15) and Order U-08-157(10) stating:

> In Order U-08-157(10)/U-08-158(10) we addressed a proposed pro forma adjustment from AWWU that annualized rate base to reflect plant placed in service during October of the test year. In Order U-10-029(15) we addressed a normalizing adjustment for plant that was placed in commercial service in August of the test year. AWWU's Anchorage Water Loop project was one of the single most important factors behind AWWU's rate case. Similarly, the Lake Dorothy hydroelectric project was one of the two main drivers behind Alaska Electric Light and Power Company's rate case in Docket U-10-029. We found that the Lake Dorothy hydroelectric project would provide a benefit to

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[100] T-11 (Dieckgraeff Reply) at 17-19.

[101] T-11 (Dieckgraeff Reply) at 19.

> ratepayers through reduced cost-of-power rates and the Anchorage Water Loop project would provide a benefit to ratepayers through increased reliability and fire protection. It was in this context that we balanced the allowance or disallowance of the proposed pro forma adjustments.[102]

We did not allow the adjustments to rate base simply because the plant was used and useful in providing utility service during the period the prospective rates will be in effect and the plant amount is known and measurable as argued by ENSTAR. We balanced approval or disallowance of the annualizing pro forma adjustments in light of the benefit of the plant to ratepayers. We allowed Alaska Electric Light and Power Company to include the Lake Dorothy hydroelectric project as plant in service for the entire year based on a finding that it provided a benefit to ratepayers through reduced cost-of-power rates.[103] And we allowed the Municipality of Anchorage d/b/a Anchorage Water and Wastewater Utility to allow the Anchorage Water Loop as plant in service for the entire year based on a finding that it would benefit customers by enhancing reliability and fire protection.[104]

ENSTAR invested $3.2 million in facilities at the Potter Gate Station and Burnt Island to allow the internal inspection of the pipeline running under the Cook Inlet. The 13-month average rate base calculation only allows the inclusion of $246,000 of the $3.2 million investment in rate base.[105] ENSTAR identified its investment at Potter Gate and Burnt Island, as well as the repair of the exposed pipeline at the Beluga River crossing

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[102] Order U-13-184(22)/U-15-096(1)/U-15-097(1), *Order Accepting Stipulation on Certain Disputed Issues, Resolving Remaining Disputed Issues, Establishing Revenue Requirement, Making Interim Rates Permanent, Establishing Permanent Rates, Ruling on Motions, Imposing Dividend Restriction, Opening Dockets of Investigation, and Approving Tariff Sheets,* dated July 16, 2015, as corrected by *Errata Notice to Order U-13-184(22)/U-15-096(1)/U-145-097(1),* dated July 28, 2015, at 30 (internal citations omitted).

[103] Order U-10-029(15) at 21-28.

[104] Order U-08-157(10)/U-08-158(10) at 26-28.

[105] T-2 (Green Reply) at 9.

and replacement of ERTs as specific, major repairs directly related to aging infrastructure, that benefit customers through a safer and more reliable system.[106] Although we denied ENSTAR's request for year-end rate base, in light of the precedent described above we review this investment to determine whether annualizing adjustments are warranted.

We have allowed annualizing pro forma adjustments for plant placed in service during the test year that provides a benefit to ratepayers, such as a reduction in costs or an increase in safety and reliability. The facilities at Potter Gate and Burnt Island allow ENSTAR to inspect the pipelines under the Cook Inlet for corrosion, degradation of wall thickness, or other potential risks.[107] These facilities allowed the first in-line inspection of the 10-mile stretch of pipeline which was installed before the 1964 Good Friday Earthquake.[108] ENSTAR was required to replace a section of the Beluga pipeline after the bank of the Beluga River eroded away, leaving the pipeline exposed.[109] The ability to inspect pipelines not accessible by land and the replacement of a section of pipeline exposed by river erosion, are projects that benefit ratepayers through increased safety and reliability of the pipeline system.

ENSTAR replaced over 50,000 ERTs during the test year, allowing ENSTAR to use vehicle-mounted equipment to read meters by driving through neighborhoods and receiving signals from the meters without the need to physically visit and visually read each meter. The ERTs ultimately lower ENSTAR's costs.[110] Lower costs provide a benefit to ratepayers.

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[106] ENSTAR Post-Hearing Brief at 17-18; T-10 (Dieckgraeff Direct) at 18, 20.

[107] T-1 (Green Direct) at 22.

[108] T-2 (Green Reply) at 8.

[109] T-1 (Green Direct) at 28.

[110] T-10 (Dieckgraeff Direct) at 20.

The facilities at Potter Gate and Burnt Island, as well as the replacement of exposed pipe at the Beluga River, provide a benefit to ratepayers through increased safety and reliability such that, on balance, an annualizing pro forma adjustment is warranted. The ERT replacement operates to lower costs such that, on balance, an annualizing pro forma adjustment is warranted. We allow ENSTAR to make pro forma adjustments to account for Potter Gate and Burnt Island facilities ($3.2 million), Beluga River pipeline replacement ($2.5 million), and ERT replacement ($4.7 million) as plant in service for the entire test year.

Historical Stored Gas Capacity and Reservation Fees

ENSTAR included approximately $57.7 million attributable to stored gas costs in rate base.[111] Of this amount, the cost of gas stored is $32.4 million, reservation charges are $11.8 million, and capacity charges are $13.6 million.[112] The reservation and capacity charges are paid to CINGSA. The AG agrees that the reservation and capacity charges are reasonable as they are based on approved tariffed rates.[113] However, the AG argues that while ENSTAR should have the opportunity to recover the $25.3 million in reservation and capacity fees, ENSTAR should not be allowed to include the amount in rate base and earn a return on the fees.[114] The cost of gas stored is not in dispute.[115]

The AG claims that the reservation and capacity fees are prior period operating expenses and standard ratemaking principles do not allow a utility to earn a return on operating expenses. The AG also asserts that the deferred collection of the

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[111] T-11 (Dieckgraeff Reply) at 20; T-14 (Fairchild-Hamilton) at 100.

[112] T-14 (Fairchild-Hamilton) at 100. The amounts total more than $57.7 million due to rounding.

[113] T-14 (Fairchild-Hamilton) at 100.

[114] T-14 (Fairchild-Hamilton) at 100-106, JKF-2, RAPA Adjustment 21.

[115] T-11 (Dieckgraeff Reply) at 31.

reservation and capacity fees was a flawed methodology. The AG claims that ratepayers should not be required to pay a return that results from the use of a flawed ratemaking methodology. Finally, the AG states that the reservation and capacity fees are paid to CINGSA, an affiliate of ENSTAR. Allowing a return on the fees would result in a "second layer of return" for ENSTAR's parent company.[116]

JL Properties did not file testimony, but argued against inclusion of past storage fees for stored gas in rate base. JL Properties asserted that these are operating costs and as such are not entitled to a return.[117]

ENSTAR argues that there is no meaningful distinction between the storage fees and the cost of gas itself. ENSTAR asserts that both are investment costs that warrant a return.[118]

ENSTAR claims that the costs for historic reservation and capacity fees are accounted for in compliance with generally accepted accounting principles and in accordance with our orders. ENSTAR asserts that during the test year these costs were properly recorded as a cost of stored gas. ENSTAR states that when the gas is delivered to customers it is removed from the cost of stored gas and charged to the GCA. ENSTAR argues that at no time are reservation and capacity fees an operating expense of ENSTAR.[119]

ENSTAR states that we have the authority to determine the proper treatment of fees related to gas storage, and we have approved ENSTAR's past treatment

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[116] T-14 (Fairchild-Hamilton) 102-105.

[117] JL Properties Post-Hearing Brief at 34-35 (citing T-14 (Fairchild-Hamilton) at 105-106).

[118] T-11 (Dieckgraeff Reply) at 20.

[119] T-11 (Dieckgraeff Reply) at 28-29. Going forward, reservation and capacity fees will be recovered through ENSTAR's GCA. *See* Order U-16-066(6).

of the fees. Therefore, ENSTAR asserts that the AG's claim that ENSTAR used a flawed ratemaking methodology is incorrect. ENSTAR states that it has followed the specific accounting directions in our orders and our orders were based on publically filed proposals. ENSTAR further asserts that the AG had the opportunity to file comments or propose changes to the past methodologies for treating reservation and capacity fees, but did not do so.[120]

ENSTAR originally recovered its costs of gas withdrawn from storage (including transportation, reservation, and capacity fees) as well as financing costs on the balance of gas in storage as proposed in TA214-4. ENSTAR had anticipated that it would cycle all gas in storage within 24 months or less. We authorized recovery of the fees and their associated carrying costs based on the average monthly balance of stored gas (including all CINGSA storage fees) at the prime rate charged by ENSTAR's lead bank on the last day of each month.[121] In Docket U-14-111, ENSTAR proposed the inclusion of its stored gas costs in rate base and the corresponding removal of financing cost charges from the GCA. Docket U-14-111 was resolved through settlement, which we accepted in Order U-14-111(18). ENSTAR states that Order U-14-111(18) approved revised ENSTAR tariff sheets that removed the storage fee financing costs from the GCA provision.[122] ENSTAR asserts that it then began earning its authorized rate of return on the stored gas account balance.[123] ENSTAR states that going forward, the amount of

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[120] T-11 (Dieckgraeff Reply) at 29.

[121] T-11 (Dieckgraeff Reply) at 22-25; Letter Order No. L1100562, dated October 26, 2011. A comprehensive discussion of the inclusion of carrying costs associated with stored gas is included in the tariff action memo attached to the letter order.

[122] T-11 (Dieckgraeff Reply) at 25-26.

[123] T-11 (Dieckgraeff Reply) at 25-27.

past, uncollected reservation and capacity fees will be reduced as gas in storage is cycled, and the amount in rate base will decrease accordingly.[124]

ENSTAR argues that CINGSA and ENSTAR have different owners, charge different rates, and hold separate certificates of public convenience and necessity. ENSTAR asserts that the AG is incorrect in claiming that there is double return recovery because the two companies are separate and should have separate returns.[125] ENSTAR claims that the affiliate relationship between ENSTAR and CINGSA does not change the analysis because the firm storage contract specifying the reservation and capacity fees was filed with and approved by this commission and the reservation and capacity fees are tariffed rates.[126]

ENSTAR has appropriately accounted for the reservation and capacity fees as a cost of stored gas inventory, not an expense. Further, ENSTAR's treatment of the fees has been in conformity with our past decisions and the fees are based on approved tariffed rates. We find ENSTAR's arguments that the past reservation and capacity fees should be included in rate base as a cost of stored gas inventory persuasive. ENSTAR is authorized to include the past reservation and capacity fees in rate base until they are eliminated as gas in storage is cycled through CINGSA.

Prudence of Capital Investment in Lateral to Access CINGSA Gas Supply

During the test year, ENSTAR installed a 4.2 mile transmission pipeline to connect its transmission system to the CINGSA storage facility. ENSTAR states that the transmission line creates redundancy of access to the storage facility, saves ENSTAR's

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[124] T-11 (Dieckgraeff Reply) at 31.

[125] T-11 (Dieckgraeff Reply) at 30. ENSTAR states that MEA witness Lawton makes a similar "incorrect" argument.

[126] Tr. 1844 (Dieckgraeff).

customers on the cost to transport gas, and conserves energy by allowing the higher pressure gas in the CINGSA storage facility to flow into the transmission system without the need for pressure decreases and later recompression.[127] The lateral was available for use in mid-summer 2015.[128] ENSTAR, Chugach and ML&P began using the lateral in November 2015 and HEA began use in 2016.[129]

HEA presented testimony arguing that the costs of the lateral were not prudently incurred.[130] HEA stated that ENSTAR did not hold an open season to evaluate shipper interest before construction of the lateral and did not "determine the potential for integrated system cost savings associated with the CINGSA Lateral project." HEA argues that ENSTAR increased its rate base by $11.7 million through construction of the lateral for a project that will not increase volumes or revenue from new customers.[131]

HEA asserts that the benefit, if any, to the ENSTAR pipeline system from the lateral is to increase deliveries to customers in Anchorage, but by including the costs in postage stamp rates, customers who don't benefit from the lateral will pay for it. HEA argues that the primary purpose of the CINGSA storage facility is to serve distribution load and the costs of transporting gas to the distribution customers, including the costs of the lateral, should be borne by those customers.[132]

HEA asserts that we should disallow recovery of the costs associated with the lateral. HEA claims that ENSTAR has not demonstrated that its decision to construct

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[127] T-1 (Green Direct) at 21; *See* Docket U-15-087.

[128] T-10 (Dieckgraeff Direct) at 19.

[129] T-10 (Dieckgraeff Direct) at 19; T-11 (Dieckgraeff Reply) at 85-86; T-22 (Salzetti) at 19; H-102; Tr. 504 (Dieckgraeff).

[130] T-22 (Salzetti) at 6-12.

[131] T-22 (Salzetti) at 7-8.

[132] T-22 (Salzetti) at 8.

the lateral was prudent; that ENSTAR did not hold an open season; that HEA will incur additional costs rather than saving transportation costs; and that savings asserted by ENSTAR related to deferred upgrades are illusory. In the alternative, HEA asserts that we should disallow the inclusion of the lateral in postage stamp rates and order an incremental rate, a contribution in aid of construction, or a surcharge to recover the costs of the lateral.[133]

MEA and JL Properties engaged in cross-examination at hearing and presented argument that the lateral was not prudent,[134] but did not present affirmative testimony on the issue.

ENSTAR testified that the lateral provides redundancy or access "coming out of the most important delivery mechanism that ENSTAR has to bring gas to its customers and that Southcentral Alaska needs."[135] ENSTAR asserts that utility customers that do not use the lateral receive a benefit by "redundancy of the full system."[136] ENSTAR claims the lateral provides a benefit to the entire system by allowing the entire system to operate at higher flows and higher pressures.[137]

A utility's costs are presumed to be prudently incurred. A party challenging prudence has the burden to make a substantial showing that the challenged costs were imprudently incurred. Only if the party challenging prudence has created a serious doubt will we then proceed to determine whether the utility has dispelled this doubt and proven the decision prudent.[138]

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[133] T-22 (Salzetti) at 11-12.

[134] MEA Closing Brief at 10-11; JL Properties Post-Hearing Brief at 31-34.

[135] Tr. 324 (Green).

[136] Tr. 324 (Green).

[137] Tr. 430 (Green).

[138] Order U-16-094(3)/U-17-008(7) at 2-3 (citing Order U-10-029(15) at 8).

When we approved the service area expansion necessary to allow the construction of the lateral we found that:

> [T]he Lateral will benefit the public by increasing the efficiency and deliverability of gas to CINGSA's customers by improving system reliability, by providing a second access pipeline to CINGSA, and by reducing transportation costs incurred by CINGSA's customers. We find the service area expansion is required for the public convenience and necessity.[139]

We stated that legitimate public convenience and necessity benefits through construction of the lateral included "an increase in APLC's system efficiency and deliverability through decreased compression requirements and improved transmission system reliability."[140]

The testimony presented by ENSTAR in this docket confirms that the increased transmission system reliability anticipated by Order U-15-087(2) has been achieved in actual operation. The intervenors failed to make a substantial showing that the challenged costs were imprudent. Further, even if there had been such a showing, the record in this docket on the benefits of the lateral to the reliability of the ENSTAR system is sufficient to dispel any doubt and prove the decision to build the lateral prudent.

Cash Working Capital, Lead-Lag Study, and Prepayments

ENSTAR filed a lead-lag study as the basis for its cash working capital requirement as required by the stipulation accepted in Order U-14-111(18).[141] The lead-

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[139] Order U-15-087(2), *Order Approving Application to Expand Authorized Service Area, Approving Service Area Map, Approving Service Area Description, Denying Motion for Expedited Consideration, Denying Petition to Intervene, and Closing Docket*, dated December 4, 2015, at 7.

[140] Order U-15-087(2) at 9.

[141] T-5 (Lyons) at Exhibit TSL-2, Exhibit TSL-3; Order U-14-111(18), *Order Accepting Stipulation, Approving Tariff Sheets, and Extending Statutory Timeline*, dated September 29, 2015, at Appendix A.

lag study results in a negative cash working capital (CWC) requirement of ($844,746).[142] The negative CWC requirement indicates that ENSTAR receives customer payments in less time than it takes for it to pay its expenses and results in a net reduction to rate base. The CWC calculation is based on the results of the lead-lag study, which are then applied to the requested Operations and Maintenance (O&M) expenses, income taxes, and taxes other than income taxes proposed by ENSTAR.[143] Although the lead-lag study was not challenged, the AG proposed to remove prepayments, in the amount of approximately $1.66 million, from rate base because of an alleged potential for "conceptual double counting."[144]

ENSTAR described the lead-lag study process as follows. The revenue lag is measured in days from the time the service is provided to customers until the time the payment is received from customers and available to ENSTAR. The expense lag is measured in days from the time a service is provided to ENSTAR until the time ENSTAR makes payment for that service. The difference between the revenue and expense lag determines if there is a net revenue lag (revenue lag days are greater than the expense lag days) or a net expense lead (revenue lag days are less than the expense lag days). The difference between the revenue lag and the expense lag is the net lag, effectively the lead lag days used in the calculation of the CWC allowance.[145]

The revenue lag consists of the service lag, the billing lag, and the collection lag. The total number of days produced by the three components represents the amount of time between providing gas utility service to customers and the receipt of related

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[142] T-5 (Lyons) at 6, 14, Exhibit TSL-2. The prefiled testimony included the amount of $834,762 and was revised to $844,746. Tr. 659.

[143] T-5 (Lyons) at 6.

[144] T-15 (Smith) at 35-40.

[145] T-5 (Lyons) at 7.

revenues for such service. Each of the revenue lag components were added together to arrive at a total revenue lag of 40.10 days.[146]

The expense lag includes the following components: O&M expenses, income tax expenses, taxes other than income tax, and other adjustments such as regulatory charges. To determine the O&M expense to be included in the lead-lag study, ENSTAR separated the O&M expenses into four groups: purchased gas costs, payroll costs, affiliate charges, and third party O&M expenses. ENSTAR then determined the lag days for each of those categories. The third party O&M expenses included items such as rental equipment, hardware supplies, utility services, and maintenance services. Because ENSTAR has thousands of invoices over the course of a year, ENSTAR relied on a sampling to measure expense lags. The lead-lag study resulted in an expense lag of 23.47 days for third party O&M expenses.[147]

The AG asserted that prepayments are included in the O&M expenses on which ENSTAR computed a CWC allowance. Specifically, the AG claims that ENSTAR included the expense associated with prepayments in the "Other Third-Party O&M Expenses." The AG argues that the inclusion of prepayments in the O&M expenses (on which the CWC is calculated) and in rate base, would "conceptually double count" the amount assumed to be provided by investors to fund such expenses before ENSTAR receives revenues from ratepayers to cover such expenses. The AG recommends the removal of the 13-month average of prepayments from rate base ($1.66 million), while leaving the prepaid expenses in the Other Third Party O&M Expenses line item of the lead-lag study, to remove the conceptual double counting of prepaid expenses.[148]

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[146] T-5 (Lyons) at 8-9.

[147] T-5 (Lyons) at 10-12.

[148] T-15 (Smith) at 35-36.

The AG states that ENSTAR did not calculate a specific payment lag for prepayment amortization expense in calculating its proposed expense lag. The AG states that ENSTAR instead included prepaid expenses in the line item for Other Third Party O&M Expenses. The AG states that the list of invoices used to develop the payment lag does not appear to include any of the categories that were included in prepayments in rate base.[149]

The AG states that ENSTAR included prepayment amortization expenses in the lead-lag study and applied a net payment lag of 16.63 days, to be included in the CWC allowance. The AG also states that ENSTAR identified approximately $2.8 million for prepayment amortization expenses that is included in its lead-lag study based on its request for CWC allowance. The AG asserts it is acceptable to include the prepayment amortization expense in the CWC allowance, as long as the related balance sheet account is not included simultaneously in rate base. The AG claims that if ENSTAR does not remove prepayments from rate base, it needs to remove the prepaid expense amortization amount for the CWC allowance.[150] The AG then argues that removing prepayments from rate base is consistent with our decision to disallow prepayments in rate base in Order U-07-076(8)/U-07-077(8) and Order U-05-043(15)/U-05-044(15).[151]

ENSTAR asserts that prepayments are included in rate base because they are an upfront investment on which a utility should earn a return. ENSTAR claims the CWC allowance is intended to account for the utility's investment in the working capital required to finance the net lag between when the utility incurs an expense and when it receives the payment for that expense. ENSTAR argues there is no double counting by including prepaid expenses in rate base and the corresponding expense in the calculation

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[149] T-15 (Smith) at 37.

[150] T-15 (Smith) at 38-40.

[151] T-15 (Smith) at 40.

of the lead-lag study because the same prepaid expense is not included in prepayments and the CWC allowance at the same time. ENSTAR states that when an expense is prepaid, it is recorded as an asset in prepayments and is included in rate base. Then when the prepaid expense is amortized and charged to an expense account, it is removed from the prepayments that were recorded as an asset. ENSTAR asserts when the prepayment is amortized and charged to an expense account it is included in the lead-lag study, where it earns a return as part of the CWC allowance until it is collected through rates.[152]

ENSTAR provided a numerical example to demonstrate that there is no double counting when prepaid expenses are included in rate base and in the lead-lag study.[153] Assume that on January 1, a utility pays an annual insurance premium of $120,000, which is booked to prepayments. Each month, insurance expense is increased (debited) by $10,000 and the prepayment asset account is reduced (credited) by $10,000. For rate purposes, the average prepayment balance during the year of $60,000 is included in rate base and earns a return. Meanwhile, the rates charged to customers, include the $10,000 of insurance expense that is removed from prepayments balance in that month. The $10,000 that is removed from prepayments (and rate base) in a particular month is not collected from a customer for another approximately 40 days (a net lead lag of 16.63 days is used in the lead-lag study).[154] ENSTAR claims there is no double counting, or earning a return twice, by including the average of prepaid expenses in rate base and the expenses themselves in the lead-lag study and the CWC allowance.[155]

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[152] T-9 (Fairchild Reply) at 19-20.

[153] T-9 (Fairchild Reply) at 20-21.

[154] T-9 (Fairchild Reply) at 20-21.

[155] T-9 (Fairchild Reply) at 19-21; Tr. 922-928 (Fairchild).

We first address the AG's claim that its recommendation in this matter is appropriate because we have disallowed the inclusion of prepayments in rate base in the past. In Order U-05-043(15)/U-05-044(15), cited by the AG, we removed prepayments from rate base due to discrepancies in the record between amounts requested and itemizations on exhibits.[156] In Order U-07-076(8)/U-07-077(8), we removed prepayments from rate base because we could not tell which prepayments would continue to require an investment during the rate-effective period.[157] Neither fact pattern is implicated in this docket. Further, neither order addressed removal of prepayments from rate base as a result of the inclusion of prepayment amortization expense in CWC.

The example presented by ENSTAR is graphically reproduced as follows:

Prepayments		
1/1/2015	$	120,000
2/1/2015	$	110,000
3/1/2015	$	100,000
4/1/2015	$	90,000
5/1/2015	$	80,000
6/1/2015	$	70,000
7/1/2015	$	60,000
8/1/2015	$	50,000
9/1/2015	$	40,000
10/1/2015	$	30,000
11/1/2015	$	20,000
12/1/2015	$	10,000
12/31/2015	$	-
Average	$	60,000

Cumulative Insurance Expense		
1/1/2015		-
2/1/2015	$	10,000
3/1/2015	$	20,000
4/1/2015	$	30,000
5/1/2015	$	40,000
6/1/2015	$	50,000
7/1/2015	$	60,000
8/1/2015	$	70,000
9/1/2015	$	80,000
10/1/2015	$	90,000
11/1/2015	$	100,000
12/1/2015	$	110,000
12/31/2015	$	120,000

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[156] Order U-05-043(15)/U-05-044(15) at 29-30.

[157] Order U-07-076(8)/U-07-077(8) at 40-42.

As can be seen, it is an average that is included in prepayments in rate base. When the prepaid insurance is booked at the beginning of the year, each month thereafter, the amortization expense (one month of the expense) is removed from prepayments in rate base, and booked as an increase to insurance expense. The amount paid by removing it from prepayments (and rate base) in any month is not collected for approximately 40 days (a net lead lag of 16.63 days is used in the lead-lag study).

We find that the AG's allegation of double counting of prepaid expenses is not supported by the record. We find that ENSTAR's testimony demonstrates that there is no double counting of prepaid expenses by their inclusion in rate base and the lead-lag study. After considering the record on this issue, we decline to adopt the AG's proposal to remove $1.66 million in prepayments from rate base.

<u>Homer Extension</u>

The Homer Extension is a 22-mile distribution pipeline transporting natural gas from ENSTAR's transmission system at Anchor Point, through Homer, and terminating at the eastern boundary of Kachemak City.[158] Construction began in 2012 and was completed in the fall of 2013.[159] The construction costs of the Homer Extension were $11.8 million.[160] Of this amount, $8.2 million was funded by a State grant to the City of Homer (Homer) committed to ENSTAR as a contribution-in-aid of construction (CIAC) while the remaining $3.6 million was to be funded by a $1 per Mcf surcharge (surcharge CIAC) to customer bills in the Homer Extension area.[161] The $1 per Mcf surcharge was to be treated as a delayed recovery from customers of the CIAC required by tariff for

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[158] T-10 (Dieckgraeff Direct) at 37.

[159] T-10 (Dieckgraeff Direct) at 37.

[160] T-10 (Dieckgraeff Direct) at 38 ($11,780,072).

[161] T-10 (Dieckgraeff Direct at 37-38 ($8,150,000 state grant, $3,630,072 surcharge CIAC).

ENSTAR to build its line extension from Anchor Point to Homer.[162] The surcharge CIAC was to be in place for approximately 10 years.[163]

ENSTAR states that the $1 per Mcf surcharge has been insufficient to cover the carrying costs on its net investment in the Homer Extension and it does not appear that the surcharge will be sufficient to retire the entire amount of the $3.6 million surcharge CIAC balance.[164] ENSTAR asserts that this is because customer conversions to natural gas are lower than anticipated.[165] ENSTAR proposes to remove the surcharge CIAC and related amortization recorded since October 2013 from ENSTAR's books and include it in ENSTAR's general rate base.[166] ENSTAR also proposes to create a $1.1 million regulatory asset that would be the net of (1) the surcharge collections ($308,190); (2) CIAC amortization; (3) rate of return; and (4) income taxes recorded from October 2013 through December 2015.[167] ENSTAR proposes to amortize the regulatory asset over 7.5 years, beginning December 31, 2015, which represents the time remaining on the original ten-year period to collect the surcharge.[168] ENSTAR proposes to continue to collect the $1 per Mcf as it was integral for Homer to secure the State grant.[169] ENSTAR states that it will treat the amounts as additional Miscellaneous Income to help offset the impact of

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[162] T-10 (Dieckgraeff Direct) at 37 n.19 (citing and quoting Order U-03-084(7) at 7).

[163] H-41 (TA226-4) at 4. *See also*, H-40 (TA125-4) at 4, Attachment B at 11; Order U-03-084(7) at 7.

[164] T-10 (Dieckgraeff Direct) at 38.

[165] Tr. 364-65 (Green).

[166] T-10 (Dieckgraeff Direct) at 38.

[167] T-10 (Dieckgraeff Direct) at 38.

[168] T-10 (Dieckgraeff Direct) at 38.

[169] T-10 (Dieckgraeff Direct) at 39.

moving the surcharge CIAC amount and regulatory asset into rate base and the amortization of the regulatory asset.[170]

The AG agrees that the surcharge is not accomplishing what it was originally intended to do, i.e. recover the capital costs and return allowance.[171] The AG supports the proposal to move the original surcharge CIAC capital costs into rate base, but disagrees with continued collection of the surcharge and disagrees with the proposed creation of a regulatory asset.[172]

JL Properties did not file affirmative testimony, but engaged in cross-examination[173] and argument advocating against the inclusion of the Homer Extension in rate base.

ENSTAR developed its original proposal for a $1 per Mcf surcharge CIAC based on an economic analysis that concluded placing the Homer Extension into rate base "would place an undue burden on existing customers and that a contribution in aid of construction is in order."[174] The original proposal was developed in 2003 and was based on capital costs of $3.5 million.[175] The line extension proposed in 2003 was an 11-mile, 4" pipeline from Anchor Point to Homer and Kachemack City.[176] ENSTAR did not modify the amount, reasoning behind, or length of time over which the surcharge CIAC was expected to be collected when the tariff provisions for the Homer Extension as they exist today were proposed and approved.[177]

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[170] T-10 (Dieckgraeff Direct) at 39.

[171] T-14 (Fairchild-Hamilton) at 96.

[172] T-14 (Fairchild-Hamilton) at 97-99.

[173] *See, e.g.* Tr. 967-997.

[174] H-40 (TA125-4) at 4.

[175] H-40 (TA125-4) at 4.

[176] H-41 (TA226-4) at 2.

[177] H-41 (TA226-4) at 1.

We approved the $1 per Mcf surcharge CIAC based on ENSTAR's representations that placing the Homer Extension into rate base would place an "undue burden on existing customers." The record in this proceeding is clear that customer conversions in the Homer Extension area are less than projected by ENSTAR. And the anticipated approximate 10-year time frame for collection of the CIAC surcharge was vastly under-estimated. However, the testimony has not demonstrated a change to the premise underlying our approval of the CIAC surcharge in the first place, namely inclusion of the Homer Extension in rate base would place an "undue burden on existing customers." We deny ENSTAR's proposal to place the costs associated with the Homer Extension in rate base.

ENSTAR states that if we determine not to put the Homer Extension into rate base it will evaluate raising the $1 per Mcf surcharge.[178] ENSTAR may propose a revised surcharge amount. We will evaluate the proposal if and when it is made.

Cost of Capital

ENSTAR, the AG, and MEA each filed testimony that presented their calculation of the appropriate cost of capital for ENSTAR. ENSTAR proposed a capital structure of 48.32% debt and 51.68% equity, a cost of debt of 5.03%, a return on equity (ROE) of 12.55%, and an overall rate of return of 8.92%.[179] The AG recommended a capital structure of 48.32% debt and 51.68% equity, a cost of debt of 5.06%, ROE of 9.825%, and an overall rate of return of 7.52%.[180] MEA recommended a capital structure

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[178] Tr. 485 (Green).

[179] T-12 (Hevert Direct) at 66-67.

[180] T-16 (Parcell) at 6.

of 48.32% debt and 51.68% equity, a cost of debt of 5.03%, ROE of 10.00%, and an overall rate of return of 7.60%.[181]

Return on Equity

ENSTAR

ENSTAR presented testimony asserting that its required ROE falls in a range between 12.50% to 14.00% and requests an ROE of 12.55%.[182] ENSTAR's requested ROE incorporates the following identified risk factors: (1) its substantial transmission assets which distinguish it from many local distribution companies (LDCs) in the Lower 48;[183] (2) natural gas supply risk;[184] (3) structural regulatory lag;[185] (4) weather risk and associated lack of a weather normalization adjustment clause;[186] (5) declining average use per customer and associated lack of a decoupling or other common revenue stabilization mechanism;[187] (6) the geographic isolation, comparatively severe climate in ENSTAR's service territory, and small size;[188] and (7) Alaska's challenging economic conditions, including its inverse relationship with the rest of the country.[189] ENSTAR uses the quarterly growth discounted cash flow (DCF), the constant growth

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[181] T-21 (Lawton) at 8.

[182] T-12 (Hevert Direct) at 66.

[183] T-12 (Hevert Direct) at 11-12; T-13 (Hevert Reply) at 7-8.

[184] T-12 (Hevert Direct) at 28-30; T-13 (Hevert Reply) at 11-12, 22-23.

[185] T-12 (Hevert Direct) at 23-25; T-13 (Hevert Reply) at 17.

[186] T-12 (Hevert Direct) at 21-23; T-13 (Hevert Reply) at 17.

[187] T-12 (Hevert Direct) at 16-21, 23-25; T-13 (Hevert Reply) at 17, 19-20, 71.

[188] T-12 (Hevert Direct) at 25-28; T-13 (Hevert Reply) at 11-17.

[189] T-12 (Hevert Direct) at 12-16; T-13 (Hevert Reply) at 19.

DCF, the capital asset pricing model (CAPM), a pipeline bond yield plus risk premium, and a gas distribution utility bond yield plus risk premium to calculate ROE.[190]

ENSTAR calculated its proposed ROE using a proxy group. ENSTAR states that ROE is a market-based concept, and as ENSTAR is not a publicly-traded entity, it is necessary to establish a group of comparable publicly-traded companies as a proxy.[191] ENSTAR asserts that a significant benefit to using a proxy group is that it serves to moderate the effects of anomalous, temporary events associated with any one company.[192]

ENSTAR selected a proxy group by starting with companies that Value Line classifies as natural gas utilities, oil/gas distribution, natural gas diversified, or pipeline master limited partnerships (MLPs).[193] ENSTAR then applied the following screening criteria: all companies in the proxy group are covered by at least two utility industry equity analysts; all companies in the proxy group have investment grade senior unsecured bond and/or corporate credit ratings from Standard & Poor's (S&P); companies have at least 40% net operating income derived from U.S. based regulated natural gas pipeline or natural gas utility operations; companies that do not pay quarterly dividends were excluded; and companies were eliminated that are currently know to be a party to a merger or other significant transaction.[194] The resulting proxy group consists of 12 companies—[195] seven LDCs and five MLPs.

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[190] T-12 (Hevert Direct) at 37-54. ENSTAR updated the models with current data as of March 17, 2017. T-13 (Hevert Reply) at 9.

[191] T-12 (Hevert Direct) at 30.

[192] T-12 (Hevert Direct) at 30.

[193] T-12 (Hevert Direct) at 33.

[194] T-12 (Hevert Direct) at 33-35.

[195] ENSTAR initially included 14 utilities in its proxy group, but removed two in reply testimony. T-13 (Hevert Reply) at 21-22.

ENSTAR calculated a quarterly growth DCF ROE range of 9.98% to 13.34% and a constant growth DCF ROE range of 9.82% to 13.07%.[196] ENSTAR's quarterly growth DCF and constant growth DCF models use a 30-day, 90-day, and 180-day average period for the stock price. The yield component of the quarterly growth model accounts for dividends being paid on a quarterly basis and incorporates the expectation of the quarterly dividend payment and the associated compounding of those dividends as they are reinvested. The yield component of the constant growth DCF assumes a constant average annual growth rate for earnings and dividend, a stable dividend payout ratio, a constant price-to-earnings multiplier, and a discount greater than the expected growth rate. ENSTAR relied on long-term growth estimates reported by Value Line, Zacks, and First Call to conduct the analysis.[197]

ENSTAR uses a CAPM analysis, which results in an ROE range of 12.15% to 13.86%. ENSTAR also uses a pipeline risk premium analysis, which results in an ROE range of 12.91% to 13.02% and a gas distribution company risk premium analysis, which results in an ROE range of 9.94% to 10.25%.[198]

AG

The AG uses the DCF, CAPM, and comparable earnings (CE) methods to calculate ROE.[199] Similar to ENSTAR, the AG used a proxy group to calculate a range for the proposed ROE.[200] The AG's proxy group consists of nine companies—seven LDCs and two MLPs. The AG selected LDCs based on the following criteria: common

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[196] T-13 (Hevert Reply) at 80.

[197] T-12 (Hevert Direct) at 38-45.

[198] T-13 (Hevert Reply) at 80.

[199] T-16 (Parcell) at 7.

[200] T-16 (Parcell) at 29.

equity ratio of 40% or greater; Value Line Safety of 1, 2, or 3; S&P stock ranking of A or B; Moodys and/or S&Ps bond ratings of A or BBB; currently pays dividends; and has not reduced dividends in the last 5 years.[201] The proxy group includes eight companies that are used by ENSTAR.[202]

The AG uses the following five indicators of growth in the DCF analysis:

1. 2012-2016 (5-year average) earnings retention, or fundamental growth (per Value Line);
2. 5-year average of historical growth in earnings per share ("EPS"), dividends per share ("DPS"), and book value per share ("BVPS") (per Value Line);
3. 2017 and 2019-2021 projections of earnings retention growth (per Value Line);
4. 2013-2015 to 2019-2021 projections of EPS, DPS, and BVPS (per Value Line); and,
5. 5-year projections of EPS growth (per First Call).[203]

The AG states that the calculation of the dividend yield takes into account the time value of money because by increasing the current raw dividend yield by one-half of the growth rate, the next period dividend rate is utilized.[204]

The AG's DCF results in an ROE of 9.3%-10.0%, with a mid-point of 9.65%; CAPM results in an ROE of 7.1%-7.3%, with a mid-point of 7.20%; and CE results in an ROE of 9.0-10.0%, with a mid-point of 9.50%.[205] The AG focuses on the highest DCF

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[201] T-16 (Parcell) at 30.

[202] T-16 (Parcell) at 30, DCP-2 at Schedule 6.

[203] T-16 (Parcell) at 36.

[204] T-16 (Parcell) at 34.

[205] T-16 (Parcell) at 59-60.

rates, as well as the highest CE rates, in order to be conservative.[206] The AG recommends a range of 9.65% to 10.0% for ENSTAR's ROE. This recommendation is higher than the CAPM findings, but incorporates the upper end of the DCF range (9.65%) and the CE range (10.0%). For this proceeding, the AG recommends an ROE of 9.5%, the mid-point of the ranges.[207]

The AG does not agree that ENSTAR has company-specific risks that should be accompanied by additional return. The AG looked at risk from a macro standpoint and considered how Moody's and Standard and Poor's considers relevant factors in establishing a credit rating. The AG states that Moody's regards the Alaska operations as a positive factor, while ENSTAR claims that geographic isolation is a risk. The AG states that any costs associated with risk should be part of operating costs that ENSTAR is requesting; as such, ratepayers are already paying rates that reflect any increased costs associated with its geographic isolation. The AG asserts that ENSTAR ignores mechanisms that it does have access to, such as requesting interim rates within forty-five days of filing a rate case, and the gas cost adjustment mechanism that allows ENSTAR to pass its all of its gas costs on to ratepayers. The AG does agree that ENSTAR has some risk because it is a combination distribution and transmission utility; however, while pipeline risk is typically higher, the pipeline part of ENSTAR accounts for less than half of ENSTAR's total operations.[208]

MEA

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[206] T-16 (Parcell) at 8.

[207] T-16 (Parcell) at 60.

[208] T-16 (Parcell) at 67-70; Tr. 2767-2772.

MEA uses the constant growth DCF, the two-stage non-constant DCF, CAPM, Empirical CAPM (ECAPM), and the risk premium to calculate ROE.[209] MEA selected its proxy group of ten companies after screening Value Line and AUS gas utility companies.[210] MEA reviewed and included some combination electric and gas utility companies to increase the size of the comparable group.[211] MEA's proxy group includes five companies that are used by both ENSTAR and the AG.

To calculate a representative price for the dividend yield, MEA examined the closing stock prices for the period July 2016 through December 2016. MEA presented the recent spot price, 52-week average, three-month average, and six-month average price in calculating the dividend yield. MEA calculated the dividend yield by applying one-half of the long-term estimates of growth to the current dividend yield. MEA calculated the yield employing the recent three-month average price and adjusting the yield by half of the growth rate.[212]

To calculate the growth rate, MEA looked at the five-year and ten-year historical growth rates in earnings per share, dividends per share, and book value per share as reported by Value Line; the Value Line forecasted growth rates in earnings per share for each company in the comparable group; the Zacks forecasted growth rates in earnings per share; and the First Call growth estimate which is readily available to investors at Yahoo Finance. MEA also examined the growth rates based on the forecasted internal growth, which is the so-called sustainable growth estimate.[213]

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[209] T-21 (Lawton) at 42-54.

[210] T-21 (Lawton) at 39-41.

[211] T-21 (Lawton) at 38.

[212] T-21 (Lawton) at 43, Schedule DJL-7.

[213] T-21 (Lawton) at 46-47, Schedule DJL-6.

MEA's DCF results in an ROE of 9.24%-9.26%, with a mid-point of 9.25%; two Stage DCF results in an ROE of 9.05-9.18%, with a mid-point of 9.12%; CAPM results in an ROE of 8.52%-8.56%, with a mid-point of 8.54%; ECAPM of 8.71%-8.99%, with a mid-point of 8.85%; and a risk premium ROE of 9.37% to 9.54%, with a midpoint of 9.46%. MEA recommends an ROE of 10%, which takes into consideration ENSTAR's current stable financial condition, on-going construction program, capital structure, and the lack of regulatory recovery mechanisms.[214]

MEA argues that ENSTAR has no unusual business or financial risk.[215] MEA states that current economic conditions do not warrant high returns for utility companies. MEA claims that while the financial markets and economy have experienced periods of uncertainty and turmoil since September 2008, interest rates have remained low and are likely to remain low.[216] MEA asserts that ENSTAR is no more or less risky than the investor owned utilities in the proxy group.[217] MEA does agree that the one factor that may make ENSTAR slightly more risky than the comparable group is the lack of rate recovery and/or decoupling mechanisms.[218]

Fair and Reasonable ROE

The expert testimony that was provided in this docket was credible and presented by well qualified, experienced experts. The various analytical models utilized by the experts provided a broad range of potential ROEs from 7.1% to 14% with the

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[214] T-21 (Lawton) at 52-54.

[215] T-21 (Lawton) at 55-56.

[216] T-21 (Lawton) at 33-35.

[217] T-21 (Lawton) at 53.

[218] T-21 (Lawton) at 33-35, 53-56.

specific recommendations presented in a range from 9.5% to 12.55%. We apply our reasoned judgement to the record presented to determine a fair ROE for ENSTAR.[219]

We note that while both the AG and MEA presented testimony disputing ENSTAR's discussion of company-specific risk factors, the testimony from ENSTAR that its authorized ROE has consistently included a premium relative to natural gas utilities in the Lower 48 remained largely unrebutted.[220] Our evaluation of a fair ROE includes an assessment of the risk factors identified by ENSTAR.

(1) Substantial transmission assets

ENSTAR asserts that its substantial transmission assets (40% of total plant), result in increased risk relative to Lower 48 LDCs. This risk factor is generally moderated by the selection of a proxy group that includes MLPs as well as LDCs. We find this factor increases ENSTAR's risk profile.

(2) Natural gas supply risk

ENSTAR does not connect with other gas-producing regions and is entirely dependent on a small number of gas producers in the Cook Inlet. Lower 48 gas distribution utilities have access to a diverse supply portfolio.[221] ENSTAR's existing supply contracts expire in 2018, and ENSTAR only has partial supply commitments to meet its needs through 2023.[222] We find that this factor increases ENSTAR's risk relative to Lower 48 LDCs.[223]

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[219] Order U-13-184(22) at 54.

[220] T-12 (Hevert Direct) at 32.

[221] Tr. 2688-89 (Hevert).

[222] T-1 (Green Direct) at 31-32.

[223] *See* Tr. 1635-38 (Smith).

(3) Structural regulatory lag

ENSTAR asserts that our statutory scheme does not currently authorize many mechanisms that may reduce regulatory lag. ENSTAR identifies our use of a historical test year; 15-month rate case timeline; and lack of trackers or similar mechanisms to facilitate timely recovery of new investment, as components that result in regulatory lag. ENSTAR downplays the availability of interim rates as a mechanism to mitigate lag based on the interest rate associated with any refunds that may be required at the end of a proceeding. However, the interest rate is only applied if we determine that the interim rates requested were higher than a just and reasonable rate. It seems counterintuitive to argue that interest on the portion of rates found not just and reasonable operates to increase risk. ENSTAR, or any utility, can mitigate this asserted risk by requesting well supported, just and reasonable rates. We find that this factor does not increase ENSTAR's risk.

(4) Weather risk and associated lack of a weather normalization adjustment

ENSTAR asserts that it faces increased risk because it does not have a weather normalization adjustment clause to account for variations in weather and the resulting effect on revenues as do utilities in other states. We note that ENSTAR has not requested such a clause for our consideration. We find that this factor increases ENSTAR's risk very slightly, if at all.

(5) Declining average use per customer

ENSTAR asserts that declining use per customer and lack of a revenue stabilization or decoupling mechanism increase ENSTAR's risk. The parties did not present a comprehensive discussion of this factor relative to the mechanisms in place, or lack thereof, for the respective proxy groups. We find that this factor increases ENSTAR's risk.

(6) Geographic isolation and small size

ENSTAR argues that Alaska's tends to be a higher cost environment due to its geographic isolation, due to increased material shipping costs, and longer procurement times. ENSTAR asserts that this multiplies the impacts the "size effect" experienced by smaller firms. We agree that both geographic isolation and ENSTAR's smaller size increase risk.

(7) Challenging economic conditions

ENSTAR asserts that Alaska's economy is currently in a recession and remains negatively correlated with the rest of the country. ENSTAR claims that with deteriorating economic conditions it faces increased risks that it will experience decreased sales, increased uncollectible and bad debt expenses, and under-recover its fixed costs, all of which make attracting capital more difficult. We agree that the current economic conditions in Alaska[224] increase risk for ENSTAR.

Although we agree that the risk factors identified by ENSTAR increase its risk, we do not attempt to quantify the amount of that increase. Rather, we take the factors into consideration when evaluating the remainder of the record and the recommendations presented by the parties. After applying our reasoned judgment to the record, we find that 11.875% represents a fair ROE for ENSTAR.

Cost of Debt

ENSTAR uses an embedded cost of debt of 5.03% in the calculation of its total weighted cost of capital.[225] ENSTAR's December 31, 2015 long-term debt balance of $149,819,635, used in the calculation of the cost of debt, consists of an intercompany

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[224] *See* Press Release from Governor Walker No. 17-112, *Governor Walker Reacts to Downgrade of Alaska's Credit Rating*, July 14, 2017.

[225] T-8 (Fairchild Direct) at 19; T-12 (Hevert Direct) at 65; H-1 (TA285-4), Attachment C at 3.

loan in the amount of $1,994,000, a term loan in the amount of $19,371,000, and senior notes in the amount of $129,135,000, which is then reduced by debt expense in the amount of $680,365.[226] Historically, ENSTAR has booked capitalized expenses incurred in connection with debt as an asset in Account 181-Unamortized Debt Expense, and amortized the expense over the life of the corresponding debt instrument. With the adoption of FASB ASU[227] No. 2015-03 in September of 2015, ENSTAR has recorded the capitalized debt expense as a reduction to the amount of debt outstanding. ENSTAR has also reduced rate base by $215,382 to reflect the reclassification of debt expense from a deferred debit to a reduction in long-term debt.[228]

The AG uses a cost of debt of 5.06% in the calculation of the weighted cost of capital. In addition to reducing the long-term debt balance by the debt expense, the AG reduces the long-term debt balance by the loss on reacquired debt in the amount of $798,961, which results in a long-term debt balance of $149,020,675 to be used in the calculation of the cost of debt. The AG also proposes to reduce rate base by a total of $1,219,254, which consists of $328,105 for debt refinancing and $891,149 for unamortized loss on reacquired debt, to remove debt expense and the loss on reacquired debt from rate base.[229] ENSTAR agrees to the AG's proposal provided (1) a corresponding adjustment is made to the capital structure to reflect the lower amount of net debt and removal of certain debt from rate base; and (2) the amount of debt in the capital structure properly matches the amount of debt used to calculate the cost of debt.[230]

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[226] H-1 (TA285-4), Attachment C at 3.

[227] Financial Accounting Standards Board Accounting Standard Update.

[228] T-8 (Fairchild Direct) at 17 and H-1 (TA285-4), Attachment C at 2.

[229] T-15 (Smith) at 40-43, Exhibit RCS-3 at 3 and 4.

[230] T-9 (Fairchild Reply) at 22-23; ENSTAR Post-Hearing Brief at 49.

MEA uses ENSTAR's proposed cost of debt of 5.03% in its calculation of the total weighed cost of capital.[231]

JL Properties did not file testimony in this docket. However, through cross-examination and argument JL Properties claimed that the interest rate for ENSTAR's long term debt is excessive and does not reflect the cost of debt in today's market.[232]

We find that it is appropriate to adopt the AG's proposed cost of debt and reduction in rate base, with corresponding adjustments to ENSTAR's capital structure discussed below.

Capital Structure

ENSTAR proposes a capital structure of 48.32% debt and 51.68% equity.[233] ENSTAR's 48.32% debt is calculated using ENSTAR's proposed December 31, 2015, long-term debt balance of $149,819,635.[234] As described above, ENSTAR asserts that if we accept the AG's proposed 5.06% cost of debt, an adjustment to the capital structure is required. ENSTAR calculates the resulting capital structure as 48.19% debt and 51.81% equity.[235] The 48.19% debt is calculated using the December 31, 2015, long-term debt balance of $149,020,675, which takes in to consideration the AG's proposal.

The AG and MEA both utilize a capital structure of 48.32% debt and 51.68% equity in their respective recommendations.[236]

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[231] T-21 (Lawton) at 8, 55.

[232] JL Properties Post-Hearing Brief at 44; Tr. 573-594.

[233] T-12 (Hevert Direct) at 65; H-1 (TA285-4), Attachment C at 3.

[234] H-1 (TA285-4), Attachment C at 3.

[235] T-9 (Fairchild Reply) at 22.

[236] T-16 (Parcell) at 28; T-21 (Lawton) at 54.

JL Properties did not present affirmative testimony. However, JL Properties engaged in cross-examination and argument asserting that we should set ENSTAR's capital structure with an equity range of 45-50%.[237]

Because we adopted the cost of debt proposed by the AG, we adjust the capital structure and approve a capital structure of 48.19% debt and 51.81% equity.

Total Weighted Cost of Capital

Based on the above decisions we calculate ENSTAR's total weighted cost of capital as follows:

ENSTAR Natural Gas Company Cost of Capital Test Year Ended December 31, 2015			
Capital Component	**Capital Structure**	**Cost**	**Weighted Cost**
Debt	48.19%	5.06%	2.44%
Equity	51.81%	11.875%	6.15%
Total Weighted Cost of Capital			**8.59%**

Expenses

Total Compensation Package

The AG proposes the disallowance of $1.6 million in compensation asserting that it represents bonus compensation that should not be recovered as an expense in ENSTAR's revenue requirement.[238] The AG argues that we have established several tests that must be met before bonus compensation is allowed in rates.[239] The AG

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[237] JL Properties Post-Hearing Brief at 41-42.

[238] T-14 (Fairchild-Hamilton) at 31-42.

[239] T-14 (Fairchild-Hamilton) at 33.

claims that first there must be a clear showing that employee salaries would be less than fully compensatory without the bonus payment.[240] Second, the AG asserts that bonus amounts must be determined in a reasonable manner.[241] And third, the AG argues that payment of the bonus may not be arbitrary.[242] The AG states that we established the first criterion in Order U-83-053(32)[243] and the second and third criteria in Order U-00-173(7).[244]

The AG presented testimony arguing that the salaries paid by ENSTAR are fully compensatory without bonuses.[245] The AG stated that for 2015 it appears ENSTAR obtained two compensation surveys, one for ENSTAR non-union professional employees and one for executives.[246] The AG asserts that based on the information provided by ENSTAR the professional salaries are fully compensatory without bonuses.[247]

The AG stated that the bonus program may be arbitrarily reduced or discontinued at the exclusive discretion of the SEMCO board of directors and its incentive plan committee.[248] The AG claims that scoring criteria for the receipt of bonuses is arbitrarily applied because nearly all employees received maximum bonuses.[249]

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[240] T-14 (Fairchild-Hamilton) at 33.

[241] T-14 (Fairchild-Hamilton) at 33.

[242] T-14 (Fairchild-Hamilton) at 33.

[243] Order U-83-053(32), *Order Deciding Substantive Revenue Requirement Issues and Requiring Permanent Rate and Applicable Refund Determinations*, dated December 4, 1986, at 29-33.

[244] Order U-00-173(7), *Order Vacating Suspensions, Approving Permanent Rates, Clarifying Compliance Requirements, Conditionally Accepting Compliance Filing, and Requiring Filing,* dated January 3, 2002, at 3-4.

[245] T-14 (Fairchild-Hamilton) at 35.

[246] T-14 (Fairchild-Hamilton) at 33-34.

[247] T-14 (Fairchild-Hamilton) at 34-35.

[248] T-14 (Fairchild-Hamilton) at 36-37.

[249] T-14 (Fairchild-Hamilton) at 39-40.

The AG stated that payment of bonuses is reliant on SEMCO achieving a target earnings before interest, taxes, depreciation, and amortization (EBITDA), asserting that the payment is not based on ENSTAR operations that benefit Alaska ratepayers.[250] The AG also argued that specific criteria used to determine whether individual ENSTAR employees receive a bonus is largely based on activities unrelated to ENSTAR service, such as criteria related to the performance of CINGSA.[251] Additionally, the AG argues that long-term incentive plan (LTIP) targets are based on operations and profit margins achieved in Michigan.[252] The AG also argues that ENSTAR service related benchmarks are applied to employees who have no control over the achievement of the particular benchmark.[253] The AG asserts that the correlation between bonus expenses and the service provided to ratepayers is weak while the correlation to shareholder profits is direct and strong.[254]

In Order U-83-053(32), we found that it is acceptable, in concept, to have a management incentive program.[255] We stated that it is a reasonable management decision for a utility to have a compensation structure for key employees that includes a bonus component, provided the overall cost is not excessive in a regulatory context.[256] We further stated that the incentives provided by a bonus program have "the potential to

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[250] T-14 (Fairchild-Hamilton) at 37-38.

[251] T-14 (Fairchild-Hamilton) at 38.

[252] T-14 (Fairchild-Hamilton) at 38.

[253] T-14 (Fairchild-Hamilton) at 39. "For example, the Manager of Gas Supply's bonus is based, in part on the number of abandoned calls to the customer service office."

[254] T-14 (Fairchild-Hamilton) at 39.

[255] Order U-83-053(32), *Order Deciding Substantive Revenue Requirement Issues and Requiring Permanent Rate and Applicable Refund Determinations,* dated December 4, 1986, at 31.

[256] Order U-83-053(32) at 31.

offer benefits for both the utility and its ratepayers in the long run."[257] In Order U-83-053(32), we found that the utility at issue, Alascom, had failed to meet its burden of proof that the expense should be included in the revenue requirement.[258] Specific to that proceeding we found that (1) there was no evidence to establish that the salaries, absent the payment of a bonus, were not fully compensatory;[259] (2) the record was unclear with respect to the scope and mechanics of the incentive plan;[260] (3) there were computational and policy issues because the bonus plan was tied to the utility's return on equity;[261] (4) the management incentive plans and payments were affiliated interest transactions;[262] and (5) the bonuses paid during the test year were based on a return on equity well in excess of that allowed in the order.[263]

Order U-00-173(7), cited by the AG, addressed costs incurred by a utility in showing appreciation to its employees such as employee service awards, memorials, gifts, the annual Christmas party, and group lunches.[264] Employee appreciation costs of this type are not equivalent to incentive compensation.[265] The second and third criteria advocated by the AG are not supported by the cited decision.

We affirm that it is acceptable for a utility to have a total compensation package that includes incentive compensation, provided that the overall cost is not

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[257] Order U-83-053(32) at 31.

[258] Order U-83-053(32) at 31.

[259] Order U-83-053(32) at 31.

[260] Order U-83-053(32) at 31-32.

[261] Order U-83-053(32) at 32.

[262] Order U-83-053(32) at 32.

[263] Order U-83-053(32) at 32.

[264] Order U-00-173(7) at 3-4; H-127, Attachment A at 3.

[265] Order U-00-088(12) at 17-18.

excessive in a regulatory context. The factors we will evaluate in our determination are specific to the proceeding at hand.

ENSTAR presented testimony that all of its salaried employees are eligible to participate in SEMCO's short-term incentive plan (STIP) while ENSTAR executives at the director level and above are eligible to participate in the LTIP.[266] ENSTAR states that its base pay salary scales are set at the 50th percentile based on surveys of similar companies.[267] Starting at the 50th percentile as the mean, learner employees receive a lower range (80-90%), fully functioning employees are set at 90-110%, and expert employees are at a higher range (110+%).[268] ENSTAR asserts that, without incentive compensation, ENSTAR would fall significantly behind organizations of similar size, industry, and geographical location.[269]

ENSTAR asserts that accomplishments such as "emergency response times are better than national averages;" "cost per Mcf being among the best in the nation;" and "American Gas Association's 2016 award for employee safety" are all directly impacted by the employee compensation plan where operational performance is a key to employees receiving an incentive compensation award.[270] ENSTAR asserts that its incentive compensation philosophy benefits ratepayers, allowing it to curb increases in costs and operate more efficiently largely due to the experience of its workforce.[271]

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[266] T-7 (Sims Reply) at 9.

[267] T-7-(Sims Reply) at 5-6.

[268] T-7-(Sims Reply) at 6.

[269] T-7 (Sims Reply) at 6-7, Exhibit JDS-5.

[270] T-7 (Sims Reply) at 7.

[271] T-7 (Sims Reply) at 8.

ENSTAR asserts that the base salaries for its executives or other salaried employees alone are not fully compensatory.[272] Compensation for union employees is set by the terms of their collective bargaining agreement.[273] SEMCO's STIP and LTIP provide incentive compensation through annual and three-year plan periods.[274] The program requirements are well documented and have been in place in substantially similar form for more than twelve years.[275]

Before incentive compensation is funded and available for payout, SEMCO must satisfy an EBITDA requirement.[276] ENSTAR stated at hearing that it "would be imprudent to pay bonuses without having the money."[277] The STIP documents individual and ENSTAR-wide performance metrics, that ENSTAR asserts are largely based on safety, reliability, and customer-focused performance.[278] ENSTAR states that with respect to ENSTAR-wide goals three items are weighted equally: (1) financial performance, including managing O&M expenses; (2) providing excellent customer service, including minimizing leak response times and abandoned call rates; and (3) maintaining a safe workplace, such as low recordable injury and preventable vehicle accident rates.[279] In addition to the EBITDA threshold for payout, an employee must achieve targets identified in their performance management plan to receive incentive

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[272] T-7 (Sims Reply) at 4, 5; Tr. 825-26 (Sims).

[273] T-7 (Sims Reply), Exhibit JDS-4 at 1.

[274] H-72.

[275] H-16; H-15; Tr. 828, 841 (Sims).

[276] T-7 (Sims Reply) at 8-9.

[277] Tr. 699 (Sims).

[278] T-7 (Sims Reply) at 10.

[279] T-7 (Sims Reply) at 11.

compensation.[280] Performance management plan goals are set and evaluated on an annual basis.[281] Low scores on ENSTAR-wide or individual metrics may result in a reduced, or no, payout.[282]

The ENSTAR-wide goals related to the LTIP focus on managing gas supply risk; ensuring system integrity and reliability; pursuing growth opportunities; maintaining excellent levels of customer care; and financial performance.[283] The ENSTAR-wide goals are one of the three requirements for an incentive compensation payout. Each of the three ENSTAR-wide metrics is weighted equally, but the listed components within each metric are not similarly weighted. Instead, they are simply factors to consider in the overall assessment of that metric.[284] ENSTAR asserts that it is appropriate to take CINGSA's performance into consideration as ENSTAR is the operator for CINGSA and allocates costs to CINGSA in relation to the storage operations.[285]

ENSTAR states that the STIP and LTIP requirements are designed to be reasonable and achievable because they are an important component of employees' total compensation.[286] During the test year, only one employee failed to meet their individual performance goals, which ENSTAR asserts confirms the reasonableness of the goals and the expectation that an employee should meet them to remain an employee.[287]

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[280] T-7 (Sims Reply) at 10.

[281] T-7 (Sims Reply) at 11-12.

[282] T-7 (Sims Reply) at 10, 12.

[283] H-15, Schedule LTI-2.

[284] Tr. 854 (Sims).

[285] Tr. 2366-2373, 2496-97 (Dieckgraeff).

[286] T-7 (Sims Reply) at 15-16.

[287] T-7 (Sims Reply) at 15-16.

ENSTAR reviewed the compensation of its top four executives against comparable energy/utility companies to ensure that ENSTAR's compensation levels remain appropriate.[288] The review included base salary levels, target total cash compensation (includes STIP), and target total and direct compensation (includes STIP and LTIP).[289]

The record establishes that the overall cost of ENSTAR's incentive compensation is reasonable in a regulatory context. The scope and mechanics of the STIP and LTIP are clearly defined and described.[290] And incentive compensation payments under the STIP and LTIP have been consistent and are expected to recur at levels comparable to the test year.[291] ENSTAR's incentive compensation plans benefit ratepayers by setting and holding employees to goals that directly relate to customer service and cost controls, and by attracting and retaining highly qualified employees to provide safe and reliable service.[292] We find that inclusion of the incentive compensation amounts as an expense in ENSTAR's revenue requirement is reasonable. Similarly, by analogy we include the supplemental executive retirement plan and related trust fee amounts, relocation allowance, housing cost, and auto allowance as expenses in the revenue requirement as part of ENSTAR's total compensation package.

ENSTAR employees are eligible for a reimbursement of up to $3.00/visit to a gym of their choice, with a maximum of $36/month.[293] The goal of the program is to

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[288] H-21 at 2.

[289] Tr. 716-717 (Sims); H-21 at 1.

[290] H-15; H-16; H-17; T-7 (Sims Reply) at 9-16.

[291] H-18; H-19; H-20.

[292] T-7 (Sims Reply) at 8.

[293] T-7 (Sims Reply) at 18.

encourage healthy behavior, which then reduces health care costs.[294] The total amount in the revenue requirement is $1,272.[295] ENSTAR self-insures its employee health care and asserts that having healthier employees naturally reduces costs.[296] Because the expense directly benefits consumers through a reduction in ENSTAR's costs, we allow its inclusion in rates.

Transmission Maintenance Expense

The AG recommends removing $207,956 in maintenance expense from ENSTAR's revenue requirement.[297] The AG states that maintenance expense for the test year was $258,970 higher than 2016 and $251,890 higher than "the average inflation adjusted cost experienced in 2011 through 2015."[298] The AG claims that the average is not presented as an adjustment but to demonstrate how "abnormally high" the test year maintenance expense was.[299] The AG asserts that it appears maintenance expense was higher than normal due to federally mandated pipeline integrity programs.[300] The AG states that during discovery ENSTAR stated the program is ongoing in nature but was not able to quantify spending for the future.[301] The AG identified $415,913 in pipeline integrity spending during the test year, then removed half as a "reasonable estimation" of what ENSTAR will incur on a recurring basis.[302]

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[294] T-7 (Sims Reply) at 18.

[295] T-7 (Sims Reply) at 18.

[296] Tr. 816-17, 834-35 (Sims).

[297] T-14 (Fairchild-Hamilton) at 74-78.

[298] T-14 (Fairchild-Hamilton) at 74.

[299] T-14 (Fairchild-Hamilton) at 74 n.51.

[300] T-14 (Fairchild-Hamilton) at 75.

[301] T-14 (Fairchild-Hamilton) at 75-76.

[302] T-14 (Fairchild-Hamilton) at 76-78.

ML&P states that ENSTAR proposes 2015 test year transmission maintenance expense of $1,901,655.[303] ML&P states that this is an increase from the $1,070,574 requested for transmission maintenance expense in ENSTAR's last rate case, Docket U-14-111.[304] ML&P states that ENSTAR budgeted $1,036,582 for transmission maintenance expense in 2016.[305] ML&P also states that ENSTAR's transmission maintenance expense for 2014 was $1,116,433.[306] ML&P states that ENSTAR addresses increased O&M expenses in general but does not specifically address the large increase in transmission maintenance expense.[307] ML&P claims that its review of the general ledger information indicated that "there are many instances of substantial increases in expenses from 2014 to 2015 and of significant expenses in 2015 that did not occur in 2014."[308] Because of this, ML&P asserts that ENSTAR's 2015 transmission maintenance expenses are abnormal and excessive.[309] ML&P claims that an average of 2014 actual expenses and 2016 budgeted expenses, resulting in $1,076,508, is a more reasonable amount to include in ENSTAR's revenue requirement for transmission maintenance expense.[310]

ENSTAR states that it has proposed recovery of the actual amount of transmission maintenance expense that it incurred during the test year.[311] ENSTAR

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[303] T-25 (Daniel) at 7 (citing T-8 (Fairchild Direct), Exhibit BHF-2 at 2 (sum of FERC accounts 861-866)).

[304] T-25 (Daniel) at 7.

[305] T-25 (Daniel) at 7.

[306] T-25 (Daniel) at 8.

[307] T-25 (Daniel) at 8.

[308] T-25 (Daniel) at 8.

[309] T-25 (Daniel) at 8.

[310] T-25 (Daniel) at 9.

[311] T-11 (Dieckgraeff Reply) at 56.

states that the funds were expended to serve utility customers and asserts that they are reasonable and reflective of costs going forward.[312] ENSTAR presented testimony that the nature of most of the expenses in the transmission maintenance accounts are for its integrity management program and that most of the time the individual expenses do not reoccur.[313]

The AG and ML&P have not sufficiently justified their proposals to adjust test year transmission maintenance expense. Rather, the record supports the use of actual transmission maintenance expense as proposed by ENSTAR. We decline to apply the adjustments proposed by the AG and ML&P.

Credit and Debit Card Processing Fees

Historically, ENSTAR arranged with a third party to accept payments from customers by credit card, debit card, and electronic check for a fee ($4.50 per transaction) that was assessed by the third party directly to the customer.[314] ENSTAR states that it received many complaints from customers who wanted to pay by credit and debit card without a processing fee. In its last rate case (Docket U-14-111), ENSTAR proposed an adjustment to its operating expenses for the estimated net annual expense of accepting credit card (and similar) payments without assessing a fee to the customer.[315] After our acceptance of the stipulation that settled the rate case, ENSTAR modified its credit card payment program and began directly accepting credit card payments in 2016.[316]

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[312] T-11 (Dieckgraeff Reply) at 56.

[313] Tr. 2071-72 (Dieckgraeff).

[314] T-10 (Dieckgraeff Direct) at 31.

[315] T-10 (Dieckgraeff Direct) at 32.

[316] T-10 (Dieckgraeff Direct) at 32.

In the current proceeding, ENSTAR proposes to increase test year expenses by $835,324 to accommodate acceptance of credit card payments directly from customers with no separate fee.[317] This amount is based on a transaction fee of $1.39 per transaction with approximately 84,000 credit card transactions per month (assumed use rate of approximately 60%).[318] ENSTAR states that its projected use rate is based on the experiences of other utilities and uses Anchorage Water and Wastewater Utility (AWWU) (approximately 42% usage) as an example.[319]

The AG presented testimony arguing that the 60% usage rate assumed by ENSTAR is not reasonable.[320] The AG stated that the AWWU usage rate cited by ENSTAR is 40% and information relied upon by ENSTAR and provided in discovery shows that 46% of payments for all consumer spending is paid by credit card.[321] The AG states that ENSTAR processed 267,147 credit card transactions in 2016, 26.8% of the number of transactions used by ENSTAR to calculate its proposed credit card expense adjustment.[322] The AG proposed a reduction of $600,031 to ENSTAR's proposed credit card adjustment based on the 2016 data.[323]

ENSTAR states that it implemented the credit and debit card payment option in response to overwhelming customer requests.[324] ENSTAR argues that the reduction proposed by the AG only incorporates 11 months of the program and assumes

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[317] T-10 (Dieckgraeff Direct) at 32-33.

[318] T-10 (Dieckgraeff Direct) at 32.

[319] T-10 (Dieckgraeff Direct) at 32.

[320] T-14 (Fairchild-Hamilton) at 72-73.

[321] T-14 (Fairchild-Hamilton) at 72.

[322] T-14 (Fairchild-Hamilton) at 72.

[323] T-14 (Fairchild-Hamilton) at 73.

[324] T-7 (Sims Reply) at 3, 19, 20; Tr. 725, 784-85, 870 (Sims).

that credit card usage will not grow.[325] At hearing, ENSTAR testified that it had approximately 43,000 credit card transactions in May 2017, the highest number it has had to date.[326] This equates to about 30% of ENSTAR's customers using the program.[327]

The record does not support the 60% usage rate presumed by ENSTAR. Currently, approximately 30% of ENSTAR customers pay with a credit card, while the usage rates experienced by AWWU and the national data relied upon by ENSTAR are in the mid-40%. We do not find that it is reasonable for all customers to pay for an expense that operates as a convenience to only a minority of customers. We disallow the entirety of ENSTAR's proposed inclusion of credit card processing fees in its revenue requirement.

<u>Payroll Expenses</u>

ENSTAR proposes an adjustment to account for changes in the number, composition, and compensation of ENSTAR personnel compared to test year data.[328] ENSTAR states that the proposed adjustment consists of three components: (1) updating test year employee count, hours worked at current wage levels, and other measurable compensation increases; (2) normalizing test year employee count and hours worked for (a) positions where vacancies occurred during the test year, (b) positions that were eliminated during the test year, and (c) positions that were added during the test year; and (3) post-test-year known and measurable changes for positions eliminated or added.[329]

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[325] T-7 (Sims Reply) at 18-19.

[326] Tr. 742-43 (Sims).

[327] Tr. 833-34 (Sims).

[328] T-10 (Dieckgraeff Direct) at 28-31.

[329] T-10 (Dieckgraeff Direct) at 28-31.

The first component was developed by reviewing personnel rules on a position by position and person by person basis. Then wage rates were adjusted to reflect salary and wage rates for each non-union position in effect at April 1, 2016.[330] For union represented clerical and operations employees, wage rates were adjusted to reflect scheduled grade changes along with a 1.5% across-the-board wage increase specified by union contract that becomes effective April 1, 2017.[331] This part of the adjustment increases ENSTAR's revenue requirement by $646,951.

The second component was calculated by adjusting the hours worked to reflect the normal annual number of hours for every position that was added or partially vacant during the test year.[332] Hours and amounts for positions that were eliminated during the year were removed.[333] This part of the adjustment increases ENSTAR's revenue requirement by $227,459.

Third, ENSTAR adjusted for positions that have been eliminated or added post-test year.[334] This part of the adjustment decreases ENSTAR's revenue requirement by $68,262. The total proposed adjustment is an $806,148 increase to the revenue requirement.

The AG argues that parts two and three of ENSTAR's proposal, adjusting employee count and hours worked, are not supported by precedent.[335] The AG recommends disallowing the second and third components of the proposed adjustment,

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[330] T-10 (Dieckgraeff Direct) at 28.

[331] T-10 (Dieckgraeff Direct) at 28-29.

[332] T-10 (Dieckgraeff Direct) at 29.

[333] T-10 (Dieckgraeff Direct) at 29.

[334] T-10 (Dieckgraeff Direct) at 30.

[335] T-14 (Fairchild-Hamilton) at 47-53.

resulting in a $159,197 reduction to ENSTAR's proposed adjustment.[336] The AG cites Order U-08-157(10)/U-08-058(10) as clear precedent that known and measurable adjustments to wage rates are appropriate but that number of employees should be held constant.[337]

In Order U-08-157(10)/U-08-158(10), we allowed AWWU to use updated wage rates that were known and measurable at the time it filed its rate case.[338] We required AWWU to hold the number of employees constant and then adjust its wage rates for known and measurable changes.[339] We affirmed this approach in Order U-13-184(22)/U-15-096(1)/U-15-097(1).[340] We allowed ML&P to utilize test year employee levels and adjust for known and measurable pay increases.[341]

Consistent with our precedent, we will allow ENSTAR to make a pro forma adjustment to update wage rates for known and measurable changes. We agree with the AG that the second and third component of ENSTAR's proposed adjustment should be denied. We allow an overall increase to ENSTAR's revenue requirement of $646,951.

<u>Insurance</u>

ENSTAR proposes an insurance expense adjustment to calculate "the normalized annual expense for all policies (including broker fees) purchased and/or

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[336] T-14 (Fairchild-Hamilton) at 54.

[337] T-14 (Fairchild-Hamilton) at 52-54.

[338] Order U-08-157(10)/U-08-158(10), *Order Resolving Revenue Requirement Issues,* dated February 11, 2010, at 23-24.

[339] Order U-08-157(10)/U-08-158(10) at 24.

[340] Order U-13-184(22)/U-15-096(1)/U-15-097(1), *Order Accepting Stipulation on Certain Disputed Issues, Resolving Remaining Disputed Issues, Establishing Revenue Requirement, Making Interim Rates Permanent, Establishing Permanent Rates, Ruling on Motions, Imposing Dividend Restriction, Opening Dockets of Investigation, and Approving Tariff Sheets,* dated July 16, 2015, as corrected by *Errata Notice to Order U-13-184(22)/U-15-096(1)/U-145-097(1),* dated July 28, 2015, at 12-15.

[341] Order U-13-184(22)/U-15-096(1)/U-15-097(1) at 15.

renewed during the past 12 months."[342] The adjustment covers property, liability, and various other insurance policies purchased by ENSTAR.[343] ENSTAR states that in order to reflect current insurance expense levels, the December 2015 amortization expense of its current insurance policies was annualized and combined with the broker fee incurred during the test year.[344] The difference between the test year-end annualized expense and the 2015 test year amount, adjusted for the portion capitalized or reimbursed, results in the proposed $33,239 increase to test year insurance expense.[345] ENSTAR argues that annualized December 2015 insurance expense is "clearly more representative" of ongoing insurance expense levels and reflects the most recent known and measurable increases or decreases in premiums.[346] At hearing, ENSTAR stated that the intent was to match the insurance premiums with year-end rate base.[347]

The AG recommends disallowance of the proposed insurance expense adjustment arguing that basing insurance costs on the last month of the test year is not reasonable.[348] The AG claims that there is no reason to believe that December 2015 insurance expense (multiplied by 12) is more representative than the entire test year insurance costs will be on a going forward basis.[349] The AG argues that insurance premiums may increase (due to inflation) or decrease (due to good safety ratings or

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[342] T-10 (Dieckgraeff Direct) at 34.

[343] T-10 (Dieckgraeff Direct) at 34.

[344] T-8 (Fairchild Direct) at 12.

[345] T-8 (Fairchild Direct) at 12.

[346] T-9 (Fairchild Reply) at 16-18.

[347] Tr. 934 (Fairchild).

[348] T-14 (Fairchild-Hamilton) at 87.

[349] T-14 (Fairchild-Hamilton) at 87.

change in insurance provider).[350] The AG asserts that the adjustment is not known and measurable and no identified commission precedent supports ENSTAR's proposed adjustment.[351]

The testimony by ENSTAR demonstrates that its various insurance policies renew on different dates throughout the year.[352] ENSTAR did not provide copies of its invoices or other evidence as to the policy premiums that came due during 2016. The premiums paid in December 2015 reflect the policies in place as of that date, but do not reflect the renewals during 2016. It is possible that the premiums increased or decreased. Additionally, neither party was able to identify any precedent where we considered and approved an adjustment to insurance expense as proposed by ENSTAR. Without evidence of the actual (known and measurable) insurance expense during 2016 we deny the proposed adjustment.

Federal and State Income Taxes

The AG proposes an adjustment to true up estimated Accumulated Deferred Income Tax (ADIT) to reflect actual 2015 ADIT.[353] Deferred income tax is an offset to rate base and is the difference between book and tax accounting.[354] A primary source of ADIT results from claiming accelerated tax depreciation.[355] In recent years, including the 2015 test year, additional bonus tax depreciation has also been available on qualified plant additions.[356] Because ADIT is a significant source of non-investor

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[350] T-14 (Fairchild-Hamilton) at 87.

[351] T-14 (Fairchild-Hamilton) at 87.

[352] T-9 (Fairchild Reply), Exhibit BHF-4.

[353] T-15 (Smith) at 53-63.

[354] T-15 (Smith) at 53-54.

[355] T-15 (Smith) at 54.

[356] T-15 (Smith) at 54-56.

supplied, cost-free capital, it is deducted from utility rate base in most jurisdictions, including Alaska.[357]

In 2016, ENSTAR made a true-up journal entry for 2015, when the tax return was filed in 2016.[358] The journal entry trued up the difference between deferred taxes recorded at year-end in the tax provision estimate, compared to the deferred taxes computed based on the actual income tax return.[359] The adjustment increased the deferred tax liability by $2.625 million.[360] If a year-end rate base were used, the adjustment would be to add the $2.625 million to deferred income tax to offset rate base.[361] If a 13-month average were to be used, the adjustment is to offset rate base by $201,919 (this equals 1/13 of $2.625 million).[362] This would be similar to reflecting the correcting entry to true up 2015 deferred income taxes for ratemaking purposes as if it were recorded on December 31, 2015, the last day of the test year, rather than in 2016 when it was recorded.[363]

Other than the issue of whether ADIT should be measured at December 31, 2015, or using an average during 2015 to correspond with the 13-month average rate base, ENSTAR agrees with the AG's adjustment to deduct ADIT from rate base.[364] The 2015 tax return had not been completed at the time the rate case was filed, therefore the ADIT included in the filing was based on estimates of depreciation expense to be taken

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[357] T-15 (Smith) at 54.

[358] T-15 (Smith) at 61.

[359] T-15 (Smith) at 61.

[360] T-15 (Smith) at 61.

[361] T-15 (Smith) at 62.

[362] T-15 (Smith) at 62.

[363] T-15 (Smith) at 62-63.

[364] T-9 (Fairchild Reply) at 23-24.

for purposes of tax year 2015.[365] In 2016, the ADIT balance at December 31, 2015 was trued up to reflect the actual amount of tax depreciation taken which increased ADIT by $2.625 million.[366] As a result, the ADIT shown on pages 2 and 4 of the revenue requirement should be increased from $24,262,681 to $26,887,681.[367]

We require ENSTAR to adjust rate base by ($201,919) to true up for 2015 actual ADIT. This amount reflects our decision above to require the use of 13-month average rate base.

Property Taxes

ENSTAR booked actual property taxes of $3,554,868 in 2015.[368] The amount for 2016 is $3,870,346.[369] The difference between 2015 and 2016 is $315,478. This is a known and measurable adjustment to reflect the rate-effective period. We require ENSTAR to adjust property tax expense by $315,478.

Miscellaneous Expenses

The AG identified a total of $322,005 of expenses that it claims should be disallowed from ENSTAR's revenue requirement.[370] The AG asserted the expenses (a) do not provide a direct benefit to ratepayers, (b) are not necessary to provide safe and reliable utility service, or (c) are non-recurring in nature.[371] The AG states that disallowing costs that do not provide a direct benefit to ratepayers or are not directly related to

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[365] T-9 (Fairchild Reply) at 24.

[366] T-9 (Fairchild Reply) at 24.

[367] T-9 (Fairchild Reply) at 24.

[368] T-9 (Fairchild Reply) at 18.

[369] T-9 (Fairchild Reply) at 19.

[370] T-14 (Fairchild-Hamilton) at 78-87.

[371] T-14 (Fairchild-Hamilton) at 78.

providing utility service is consistent with our precedent and generally accepted ratemaking principles.[372]

The AG grouped the unallowable costs into the following categories:

- $39,713 in unallowable local meals and snacks.
- $53,262 in party supplies, decorations and venues.
- $37,664 in employee perqs such as golf trips, flowers, and employee club subsidy and office snacks/coffee.
- $79,017 in charity and image advertising.
- $65,000 in lobbying expense.
- $24,154 in memberships or participation or meetings with or at civic clubs or organizations.
- $23,195 in costs to maintain a corporate apartment.[373]

At hearing the AG modified the miscellaneous expenses that it is contesting and agreed to allow $39,661[374] of miscellaneous expenses it initially removed from ENSTAR's revenue requirement.[375] The total revised amount of $282,343 that the AG continues to contest is as follows:

- $37,539 in unallowable local meals and snacks
- $49,873 in party supplies, decorations and venues
- $32,088 in employee perqs such as golf trips, flowers, and employee club subsidy and office snacks/coffee
- $76,058 in charity and image advertising
- $65,000 in lobbying expense

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[372] T-14 (Fairchild-Hamilton) at 78.

[373] T-14 (Fairchild-Hamilton) at 78.

[374] Tr. 143 (Waller). This amount includes $2,174 for food and meals, $3,389.26 for decorations/parties, $5,576.42 for gifts and perqs, $2,959.44 for image advertising, $2,368 for participation in civic organizations, and $23,194.17 for apartment expense.

[375] Tr. 143.

- $21,786 in memberships or participation or meetings with or at civic clubs or organizations, and
- $0 in costs to maintain a corporate apartment

ENSTAR asserts that the AG only conducted a cursory review of the expenses and the documentation made available by ENSTAR and made assumptions as to the nature of the expense.[376] ENSTAR claims that the items the AG disallowed which are mischaracterized, incorrect, or otherwise allowable total $183,587.37.[377]

The AG listed the general ledger line items that make up the total recommended disallowance in attachment JKF-33 to Fairchild-Hamilton's testimony.[378] ENSTAR provided attachment DMD-14 to Dieckgraeff's reply testimony in support of its argument for inclusion of the expenses. Because the parties were unable to reach agreement on these issues, our Staff reviewed in detail the supporting information provided. This information includes JKF-33, the information provided by the AG at hearing regarding the expenses it no longer disputes (referred to in this discussion for convenience as RAPA-1), and DMD-14. The results of that review, and our determinations on each category of disputed miscellaneous expense is as follows. Additionally, we disallow the $98,755.63 challenged by the AG that ENSTAR does not attempt to justify in reply.

Meals

The AG asserted that the meals it removed from ENSTAR's revenue requirement were not for employee health and safety and not required by union

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[376] T-11 (Dieckgraeff Reply) at 56.

[377] T-11 (Dieckgraeff Reply) at 69; Tr. 1840, 1842 (Dieckgraeff) for corrected amount.

[378] T-14 (Fairchild-Hamilton), JKF-33.

contract.[379] The AG cited Order U-99-130(13) for the proposition that food and snack expenses are not necessary for the delivery of utility service.[380] The AG also quoted Order U-00-088(12):

> We have previously disallowed the costs of meals for ratemaking purposes because they are not expenses associated with utility service. In this category, rates should include only costs that ENSTAR has justified as necessary by showing, for example, that the expenses are required for the health and safety of employees or are required by ENSTAR's union contract.[381]

ENSTAR asserts that the AG has supported the statement that the meals that were removed are not for employee health and safety. ENSTAR claims that documentation provided by its accounting department shows that many of these meals were related to the performance of employees' jobs. ENSTAR argues there are times when an employee must work through a meal period, and the company has the obligation to make sure employees have an opportunity to eat—both for the employee's health and to ensure that employees are safely focused on the job at hand. ENSTAR also argues that evidence of this is found in the union contract, which requires ENSTAR to either provide a meal or pay a meal allowance when an employee is required to work extended hours. ENSTAR claims it would be unfair and unrealistic to apply this common sense guideline only to employees covered by a collective bargaining agreement, because the goal is for all employees to be healthy and safe while on the job.[382]

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[379] T-14 (Fairchild-Hamilton) at 81-82.

[380] T-14 (Fairchild-Hamilton) at 81.

[381] T-14 (Fairchild-Hamilton) at 82 (quoting Order U-00-088(12) at 18 (internal citation omitted)).

[382] T-11 (Dieckgraeff Reply) at 57-60.

ENSTAR disputed a total of $22,369[383] of the $37,539 that the AG proposes to remove. ENSTAR asserted that the list of meals found in JKF-33 contained several errors.

DMD-14, Attachment 1a ($565.66): ENSTAR stated that multiple items on the list were not meals at all, and should not have been disallowed.[384]

Staff reviewed JKF-33, RAPA-1, and DMD-14, Attachment 1a, noting that $100 remains in dispute. The explanation and description on Attachment 1a indicates this transaction was for CGA -Hobson- was reclassed to 76620 (this account is for Membership Dues-Other). Staff is not able to identify the nature of these dues. We disallow the $100.

DMD-14, Attachment 1a ($1,655.05): ENSTAR stated there were items in the list that were reimbursed by others and were not included in ENSTAR's revenue requirement.[385]

Staff reviewed JKF-33, RAPA-1, and DMD-14, Attachment 1a, noting that $1,225.55 remains in dispute. The explanations and descriptions on Attachment 1a indicate the transactions were for Moose's Tooth, Fred Meyer, A Pie Stop, and PAC lunch (reimbursed $272.30)/ regulatory class lunches/and CWN registration ($125). ENSTAR only identified $272.30 that was reimbursed for a PAC lunch; however, ENSTAR did not provide further details on the nature of this expense. Therefore we disallow $1,225.55.

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[383] T-11 (Dieckgraeff Reply) at 60, states the amount of $21,804; however, this amount was corrected at the hearing (page 1840 of the transcript). This is the sum of the following amounts found on DMD-14, Attachments 1a–1e: $565.66 +$1,655.05 +$1,090.09 +$4,244.10 +$7,651.01 +$7,163.31.

[384] T-11 (Dieckgraeff Reply) at 57.

[385] T-11 (Dieckgraeff Reply) at 57.

DMD-14, Attachment 1b ($4,244.10): ENSTAR asserted the AG included 31 charges that were related to ENSTAR's safety program. ENSTAR states it has a strong commitment to safety for both customers and employees, and asserts that disallowing charges related to the safety program would be harmful not only to ENSTAR, but potentially for customers.[386]

Staff reviewed JKF-33, RAPA-1, and DMD-14, Attachment 1b, noting that the entire amount of $4,244.10 remains in dispute. ENSTAR included a note on Attachment 1b indicating that two of the employees (Martinez and Pierce) listed are safety employees and their p-card purchases are related to safety. The explanations and descriptions on Attachment 1b indicate the transactions were for healthy incentive lunches, pizza for bike safety lunch,[387] reclassed p-cards for various employees, ridealong lunch, incentive lunches, bbq supplies for safety, safety goal celebrations, safety appreciation lunch, working lunch-safety, safety breakfast, and lunch for safety training.

As noted by ENSTAR, the union contract requires ENSTAR to provide meals or pay a meal allowance when an employee is required to work extended hours. The descriptions and explanations found in Attachment 1b do not indicate if the employee is a union or non-union employee; however, some of the descriptions and explanations do identify the expense as working meetings or working lunches. We believe it is reasonable for ENSTAR to treat the non-union employees and the union employees the same, and therefore, we allow these meals in ENSTAR's revenue requirement. We allow the two identified working lunches- working lunch-safety ($216.23) and lunch for safety

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[386] T-11 (Dieckgraeff Reply) at 57-58.

[387] ENSTAR was questioned at the hearing regarding this transaction. Tr. 750-752 (Sims).

training ($77.61). The remaining amount of $3,950.26 ($4,244.10 -$216.23 -$77.61) is disallowed.

DMD-14, Attachment 1c ($7,651.01): ENSTAR asserted that many of the charges were related to meals for working lunches, overtime meals, or professional organization lunches.[388] ENSTAR provided the following arguments for allowance of the charges:

> - ENSTAR employees are sometimes required to work through lunch or dinner to meet deadlines and keeping the employees fed is a prudent cost of business. ENSTAR did not include, in this amount, meals where employees simply met at a restaurant to discuss business, as these costs have historically been disallowed.
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> - For overtime meals, the union contract requires either a meal or meal ticket payment of $15.
>
> - Professional organizations, such as Chamber of Commerce or the Business Owners and Managers Association (BOMA) have lunch meetings in which ENSTAR participates. ENSTAR attends to be aware of economic trends in the area and how to best serve its customers in light of the trends and also presents information on resources and safety. These are legitimate business expenses and should be allowed in ENSTAR's revenue requirement.[389]

Staff reviewed JKF-33, RAPA-1, and DMD-14, Attachment 1c, noting that $7,462.50 remains in dispute. The explanations and descriptions included on Attachment 1c indicate the transactions were for working meals/meetings, rate case/mediation meals, overtime meals, utility group meeting, LNG lunch meeting, summit leadership breakfast/lunch, town hall meeting snacks, Alaska Oil and Gas Association (AOGA) annual lunch, Chamber of Commerce, Matsu Business Alliance, and Resource Development Council lunch.

Staff notes that AOGA is a professional trade association whose mission is to foster the long-term viability of the oil and gas industry for the benefit of all Alaskans. The AOGA represents the majority of companies that are exploring, developing,

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[388] T-11 (Dieckgraeff Reply) at 58.

[389] T-11 (Dieckgraeff Reply) at 58.

producing, refining, or marketing oil and gas on the North Slope, in the Cook Inlet, and in the offshore areas of Alaska.[390] Because AOGA is industry specific, we believe these meals can be considered a working lunch/ meeting.

Staff identified $4,910.03 of meals that were incurred for working meals/meetings. We allow these amounts. We disallow the remaining $2,552.47.

DMD-14, Attachment 1d ($1,090.09): ENSTAR asserted that the AG included meals related to out of town travel. ENSTAR claims meals provided while an employee is out of town have not yet been subject to disallowance in the past and should not be going forward.[391] Staff reviewed JKF-33, RAPA-1, and DMD-14, Attachment 1d, noting that this amount is no longer in dispute.

Exhibit DMD-14, Attachment 1e ($7,163.31): ENSTAR asserted that the AG included charges that are incidental benefits provided to employees.[392] ENSTAR cited to the following language found in Order U-07-076(8)/U-07-077(8):

> Service emblems and gifts for employees are reasonably related to providing utility service and should be allowed for rate-making purposes provided they are reasonable in amount. To avoid utility abuse of such a commission policy through excessive gifts to senior utility executives, we advise that in future cases we are prepared to disallow the expenses associated with any employee gift that would be deemed income to employee under guidelines established by the Internal Revenue Service.[393]

ENSTAR also quotes Order U-07-076(8)/U-07-077(8) for the statement "incidental benefits that are provided to employees, such as retirement gifts and coffee,

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[390] http://www.aoga.org/about. (Last visited September 19, 2017).

[391] T-11 (Dieckgraeff Reply) at 59.

[392] T-11 (Dieckgraeff Reply) at 59.

[393] T-11 (Dieckgraeff Reply) at 59 (quoting Order U-07-076(8)/U-07-077(8) at 16 (internal citation omitted)).

in the amount that is described here, approximately $10,000 per year, are not outside the range of reasonable management practices."[394]

Staff reviewed JKF-33, RAPA-1, and DMD-14, Attachment 1e, noting that the entire amount of $7,163.31 is in dispute. The explanations and descriptions included on Attachment 1e indicate the transactions were for coffee, pie and ice cream, food/prizes, donuts, employee promotion lunch, snacks, holiday party, birthday party, and department lunches. We reviewed Order U-07-076(8)/U-07-077(8), noting that the $10,000 reference was a combined amount for GHU/CUC. GHU/CUC are two separate utilities and hold two separate certificates. We required that GHU/CUC update its Cost Allocation Manual for the next rate case specifying $5,000 for each utility. The order also cited to GHU/CUC testimony that a positive relationship with its employees resulted in a compromise on health costs that saved ratepayers over $100,000.

Because the transactions are not necessary to provide utility service, and ENSTAR did not show that there were savings associated with these expenses, we disallow the total disputed amount of $7,163.31.

Party Supplies, Decorations, Venues, and Employee Perqs

ENSTAR disputed a total of $31,105[395] of the $90,926[396] that the AG proposes to remove. ENSTAR asserted that in some cases, the AG's characterization of expenses were correct, and in some they were not.[397]

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[394] T-11 (Dieckgraeff Reply) at 59 (quoting Order U-07-076(8)/U-07-077(8) at 51).

[395] This is the sum of the following amounts found on DMD-14, Attachments 2a-2d: $3,389.26 +$5,539.67 +$2,699.89 +$6,979.92 +$12,406.66.

[396] Equals $53,262 in party supplies, decorations and venues plus $37,664 in employee perqs such as golf trips, flowers, and employee club subsidy and office snacks/coffee.

[397] T-11 (Dieckgraeff Reply) at 61-63.

DMD-14, Attachment 2a ($3,389): ENSTAR asserted that the AG included $3,389 of costs related to employees who were working out of town that were allowable.[398] Staff reviewed JKF-33, RAPA-1, and DMD-14, Attachment 2a, noting that this amount is no longer in dispute.

DMD-14, Attachment 2a ($5,539.67): ENSTAR asserted that the AG identified many items as “perks” when they were related to safety or to providing service to customers. This list includes safety glasses, medical exams for Commercial Driver’s Licenses, bug spray for field employees, Transportation Worker Identification Credential card enrollment for access to Joint Base Elmendorf Richardson (JBER), equipment rental, telephone charges, hand soap for company, offices, courier service, and protective safety equipment for employees.[399] Staff reviewed JKF-33, RAPA-1, and DMD-14, Attachment 2a, noting that this amount is no longer in dispute.

DMD-14, Attachment 2b ($2,699.89): ENSTAR asserts there are $2,699.89 of expenses, which the AG removed and are related to ENSTAR’s safety program.[400]

Staff reviewed JKF-33, RAPA-1, and DMD-14, Attachment 2b, noting that the total amount of $2,699.89 remains in dispute. The explanations and descriptions provided on Attachment 2b indicate the expenses were incurred for safety bbq’s, bbq supplies, Carr’s-safety program, and employee awards. Staff identified $54.98 of expenses incurred for the safety program. We allow the safety program expenses and disallow the remaining $2,644.91.

DMD-14, Attachment 2c ($6,979.62): ENSTAR states that these are charges for coffee and tea for employees and visitors.[401]

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[398] T-11 (Dieckgraeff Reply) at 61.

[399] T-11 (Dieckgraeff Reply) at 61.

[400] T-11 (Dieckgraeff Reply) at 62.

[401] T-11 (Dieckgraeff Reply) at 62.

Staff reviewed JKF-33, RAPA-1, and DMD-14, Attachment 2c, noting that the total amount of $6,979.62 remains in dispute. The descriptions and explanations provided indicate that the items were for coffee, tea, and batteries. Because the transactions are not necessary to provide utility service, and ENSTAR did not show that there were savings associated with these expenses, we disallow the full $6,979.62.

DMD-14, Attachment 2d ($12,406.56): ENSTAR states these are charges for retirement celebrations, employee awards, flowers for employees who are seriously ill or bereaved, wellness program snacks, department snacks, and working lunches.[402]

Staff reviewed JKF-33, RAPA-1, and DMD-14, Attachment 2d, noting that $12,369.75 remains in dispute. The descriptions and explanations provided indicate that the items were for parties, flowers, celebrations, holiday breakfasts, trophies, Zumba class, employee awards, employee appreciation, jazzy gourmet popcorn, United Way events, coolers, soda, promotions for bike to work day, gift cards, get well cards, accounting snacks-working late/graduation cake, working lunch, and town hall meeting/training meeting.

Staff identified two transactions for working meals/working late- the accounting snacks/working late/graduation cake ($53) and working lunch ($59.15), which amount to $112.15. Because these expenses are work related meals we allow $112.15. The remaining expenses in the amount of $12,257.60 ($12,369.75-$112.15) are not necessary for providing utility service, and are disallowed.

Image Advertising

ENSTAR disputed a total of $28,392.77 of the $79,017 that RAPA proposed to remove. ENSTAR asserts that RAPA is correct in the characterization of some of the charges for charitable contributions, but is incorrect regarding the expenses classified as

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[402] T-11 (Dieckgraeff Reply) at 62.

image advertising. ENSTAR claims that it ensures all advertising falls under the guidelines of AS 42.05.381(a) which provides exceptions to the prohibition of public relations and lobbying expenses in rates.[403] The exceptions include reasonable amounts for:

> (1) energy conservation efforts;
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> (2) public information designed to promote more efficient use of the utility's facilities or services or to protect the physical plant of the utility;
>
> (3) informing shareholders and members of a cooperative of meetings of the utility and encouraging attendance; or
>
> (4) emergency situations to the extent and under the circumstances authorized by the commission for good cause shown.[404]

ENSTAR asserts that other advertising efforts, such as Facebook or print media ads, are aimed at keeping the public informed about utility facilities, services, and/or safety.[405]

Staff reviewed JKF-33, RAPA-1, and DMD-14, Attachment 4, noting that $25,434 remains in dispute. The descriptions and explanations provided indicate that the items were for advertising, duct tape for home show, pencils, pens, house clips, onesies, tote bags, JBER map advertising, welcome to Anchorage, Bay Realty folder, ENSTAR online order, holiday print media, audio campaign support, BOMA sponsorship, MatSu home show tables and supplies, and home show booths.

In Order U-08-157(10)/Order-08-158(10), we found that home show expenses are not reasonably related to providing utility services and did not allow their recovery in rates.[406] In Order U-13-006(10), we found that attending a BOMA convention

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[403] T-11 (Dieckgraeff Reply) at 64-65.

[404] AS 42.05.381(a)(1)–(4).

[405] T-11 (Dieckgraeff Reply) at 64.

[406] Order U-08-157(10)/Order-08-158(10) at 18-19.

did not benefit current and future ratepayers.[407] It is not clear that the expenses at issue fall under the exceptions specified in AS 42.05.381(a), with the exception of those related to ENSTAR's 811 "call before you dig" program. ENSTAR stated at hearing that they are trying as many ways as they can to get the 811 call before you dig information out to the public.[408] We allow the recovery of the $11,069 of expenses associated with "811 call before you dig." We disallow the remainder.

Lobbying Expense

ENSTAR argues that $60,000 of the $65,000 in expense that the AG proposes to disallow is a consulting contract, not a lobbying contract.[409] The contract was provided as DMD-14, Attachment 5. No invoices were submitted to support the $60,000.[410] ENSTAR agrees that $5,000 in expenses for a donation to the Governor's Inaugural Ball should be disallowed.[411]

Staff reviewed DMD-14, Attachment 5. The scope of the contract is identified as providing consulting services primarily related to the development of the in-state gas pipeline. However, the contract also recognizes that ENSTAR may require consulting services for other projects related to ENSTAR's core business. The contract initially expired in December 31, 2009, and is annotated to indicate that it is in effect until terminated. ENSTAR asserted that it received consulting services to assist with identifying and developing opportunities to enhance or provide new service and that most of the services were geared towards system expansion and increasing the existing customer base.[412] ENSTAR did not provide evidence that the contract was actually used

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[407] Order U-13-006(10) at 6-8.

[408] Tr. 1879-1881 (Dieckgraeff).

[409] T-11 (Dieckgraeff Reply) at 65.

[410] Tr. 2196-97 (Dieckgraeff).

[411] T-11 (Dieckgraeff Reply) at 66; Tr. 1876-1879 (Dieckgraeff).

[412] T-11 (Dieckgraeff Reply) at 65.

for these specific services, and that the services benefitted ratepayers. ENSTAR failed to show that the expense is necessary for providing utility service, and we disallow the $60,000 expense associated with the contract.

Legal and Outside Services

ENSTAR states that its legal and other outside services expenses for 2015 were significantly lower than any year from 2011 to 2015.[413] ENSTAR asserts that a four-year average of legal and outside service cost is more representative of the level of such costs that will be incurred during the rate-effective period.[414] ENSTAR reduces the four-year average by 42.91% to reflect the level of these costs that have been capitalized or charged to others (reimbursed) during the test year.[415]

The AG asserts that the proposed pro forma adjustment should be reversed.[416] The AG argues that our precedent in Order P-03-004(34) addressed a proposed pro forma adjustment "similar to that" proposed by ENSTAR.[417] The AG quotes language from our order stating averaging historical costs to make a pro forma adjustment is not reasonable and is not likely to produce rates that will fairly represent future costs.[418] The AG states that ENSTAR did not use the same type of analysis for other cost categories and doing so would have resulted in a $312,307 downward adjustment to maintenance expenses, for example.[419] The AG states that the legal and outside services

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[413] T-10 (Dieckgraeff Direct) at 33; H-1 (TA285-4), Revenue Requirement at Schedule H.

[414] T-10 (Dieckgraeff Direct) at 33.

[415] T-10 (Dieckgraeff Direct) at 33-34; H-1 (TA285-4), Revenue Requirement at Schedule H.

[416] T-14 (Fairchild Hamilton) at 67-69.

[417] T-14 (Fairchild-Hamilton) at 67-68.

[418] T-14 (Fairchild-Hamilton) at 67-68; Order P-03-004(34) at 10-12.

[419] T-14 (Fairchild-Hamilton) at 68.

expense amounts presented by ENSTAR show a steady and consistent downward trend.[420]

The AG claimed in prefiled testimony that $43,731 of test year legal expenses are attributable to two nonrecurring events – strike negotiations and a hearing on CINGSA's found gas.[421] The AG also claimed that $14,882 of ENSTAR's legal expenses should be disallowed for lack of sufficient information to determine whether they represent an allowable expense. The AG argued that an evaluation of ENSTAR's test year legal expenses supports a downward adjustment of $58,613 to the test year amounts.[422] At hearing, the AG agreed to the allowance of the $14,882 originally argued as unsupported.[423] It also appears that the AG withdrew the argument that $43,731 should be disallowed as nonrecurring.[424]

ENSTAR acknowledges that legal and outside services costs have declined over the five-year period, however it asserts that legal costs are episodic by nature and cannot be predicted with certainty.[425] ENSTAR argues that the AG is not consistent in its analysis of cost items in the revenue requirement study as the AG "clearly relies on averaging in its proposed adjustment to transmission maintenance expense."[426] ENSTAR states that the AG does not assert that the allegedly nonrecurring legal costs

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[420] T-14 (Fairchild-Hamilton) at 68.

[421] T-14 (Fairchild-Hamilton) at 70.

[422] T-14 (Fairchild-Hamilton) at 70.

[423] Tr. 142 (Waller).

[424] AG Post-Hearing Brief at 31. The AG argues for a reversal of ENSTAR's proposed adjustment without additional reduction.

[425] T-11 (Dieckgraeff Reply) at 53.

[426] T-11 (Dieckgraeff Reply) at 53. We denied the AG's proposed adjustment to transmission maintenance expense and allowed the actual test year amount in our discussion *supra*.

are not reasonably related to providing utility service, the standard for the inclusion of legal costs as an expense.[427] ENSTAR claims that it is appropriate to make an adjustment to reflect what it reasonably anticipates will be its costs to provide service on an ongoing basis.[428] ENSTAR states that it is a large company with approximately 200 full-time employees, and argues that legal expenses of $183,126 per year are not unreasonable.[429]

Our regulations allow adjustments to the test year for known and measurable changes or to delete or average unusual or nonrecurring events.[430] The averaging proposed by ENSTAR is not known and measurable. And legal and outside services are not unusual or nonrecurring events that may be averaged. We disallow ENSTAR's proposed adjustment to legal and outside services expense and require the use of the test year actual amount of $321,988.[431]

Rate Case Expense

ENSTAR proposed a two-part adjustment for rate case expenses, totaling $697,260.[432] One part of the adjustment annualizes and then amortizes rate case expenses from Docket U-14-111.[433] The result is $129,680 in annual amortization expense.[434] Next ENSTAR proposes estimated rate case expenses for the current docket

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[427] T-11 (Dieckgraeff Reply) at 53.

[428] T-11 (Dieckgraeff Reply) at 54.

[429] T-11 (Dieckgraeff Reply) at 55.

[430] 3 AAC 48.820(42).

[431] H-1 (TA285-4), Revenue Requirement at Schedule H.

[432] T-10 (Dieckgraeff Direct) at 34-35; H-1, Revenue Requirement at Schedule J.

[433] T-10 (Dieckgraeff Direct) at 34-35; H-1, Revenue Requirement at Schedule J.

[434] T-10 (Dieckgraeff Direct) at 34-35; H-1, Revenue Requirement at Schedule J.

of $1.8 million amortized over three years.[435] This portion of the proposed adjustment results in $600,000 of annual amortization expense related to the current rate case.[436] The result is $729,680 in annual rate case expense.[437] ENSTAR requests $32,420 of this total through test-year amortization expense associated with Docket U-14-111 and the remaining $697,260 is requested through the proposed pro forma adjustment.[438]

ENSTAR states that its $1.8 million estimate for rate case expense is based on its recent experience in Docket U-14-111, including: the number of parties and issues, excessive discovery, and our statement in Order U-14-111(18) that we expect a robust record in this proceeding.[439] ENSTAR asserts that its proposed amortization over a three-year period is in keeping with our normal policy for rate case expenses.[440] ENSTAR also states that it will true up its rate case expenses at the conclusion of this docket.[441]

The AG argues that ENSTAR is proposing a guaranteed recovery of all prior rate case costs, rather than requesting an opportunity to recover the annual rate case expense it can expect to incur on a going forward basis as required by our precedent.[442] The AG asserts that we have expressly rejected the true up of actual rate case expense, as the goal of establishing a rate case expense allowance is to allow the utility to put into rates the expected cost of presenting a normal rate case as amortized over the expected

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[435] T-10 (Dieckgraeff Direct) at 34-35; H-1, Revenue Requirement at Schedule J.

[436] T-10 (Dieckgraeff Direct) at 34-35; H-1, Revenue Requirement at Schedule J.

[437] H-1, Revenue Requirement at Schedule J.

[438] H-1, Revenue Requirement at Schedule J; T-14 (Fairchild-Hamilton) at 54 n.40.

[439] T-10 (Dieckgraeff Direct) at 34.

[440] T-10 (Dieckgraeff Direct) at 34.

[441] T-10 (Dieckgraeff Direct) at 34.

[442] T-14 (Fairchild-Hamilton) at 55-57.

period rates will be in effect.[443] The AG states that the $1.8 million in rate case expense proposed by ENSTAR is significantly higher than actual rate case expense incurred in past ENSTAR dockets.[444] The AG argues the current rate case is no more complex than Docket U-14-111, that the number of parties should not increase rate case expense above past proceedings, and litigation costs are not significantly higher than alternative dispute resolution costs.[445] The AG asserts that the primary driver behind the proposed rate case expense is the number of attorneys hired by ENSTAR.[446] The AG argues that ENSTAR may hire as many attorneys as it chooses but it is not reasonable for ratepayers to pay excessive legal costs.[447]

ENSTAR claims that the AG's arguments do not adequately assess the complexity of this docket, including the number of sophisticated and active intervenors, our statement that we expect a robust record in this case, and our aversion to black box settlements.[448] ENSTAR also states that the AG failed to address the fact that this is ENSTAR's second rate case in three years.[449] ENSTAR argues that its recent experience, in Docket U-14-111 and since the filing of TA285-4, is that these proceedings differ from past cases in complexity, timing, and number of sophisticated and active intervenors.[450]

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[443] T-14 (Fairchild-Hamilton) at 58-59.

[444] T-14 (Fairchild-Hamilton) at 60.

[445] T-14 (Fairchild-Hamilton) at 59-62.

[446] T-14 (Fairchild-Hamilton) at 63-65.

[447] T-14 (Fairchild-Hamilton) at 64-65.

[448] T-11 (Dieckgraeff Reply) at 46.

[449] T-11 (Dieckgraeff Reply) at 46.

[450] T-11 (Dieckgraeff Reply) at 47-48.

ENSTAR identifies Docket U-00-088 as an example of the difference between past proceedings and the current docket. ENSTAR states that two of the intervenors in Docket U-00-088 were primarily concerned with transportation terms and conditions and did not actively participate in the revenue requirement portion of the case, while only one had a very limited role in the rate design portion.[451] ENSTAR notes that there were only two utility intervenors in the docket.[452] ENSTAR states that contrary to the AG's claims, Docket U-00-088 was not fully litigated as the cost-of-service and rate design portions of the case were settled.[453]

ENSTAR asserts that the AG's claim that attorney costs remain the same whether a docket is resolved through negotiating a settlement or through a hearing is not realistic or in keeping with past experience.[454] ENSTAR contrasts the settlement discussions in Docket U-14-111, which took place over three days and began 10 business days after ENSTAR filed its reply testimony, with the three-week public hearing in the current docket.[455] ENSTAR states that only one expert witness was required to be on site and involved in settlement discussions during Docket U-14-111, while multiple out-of-state witnesses are required to travel to Anchorage and be available for hearing.[456] ENSTAR also states that prehearing motion practice and witness preparation requires a significant amount of time.[457]

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[451] T-11 (Dieckgraeff Reply) at 47.

[452] T-11 (Dieckgraeff Reply) at 47.

[453] T-11 (Dieckgraeff Reply) at 51-52 n.8.

[454] T-11 (Dieckgraeff Reply) at 48-49.

[455] T-11 (Dieckgraeff Reply) at 49.

[456] T-11 (Dieckgraeff Reply) at 49.

[457] T-11 (Dieckgraeff Reply) at 49.

ENSTAR asserts that given our statements that we are not interested in black box settlements and will fully adjudicate this rate case, it is more reasonable to assume that its future rate cases will receive similar examination.[458] ENSTAR also notes that ML&P, a utility with a smaller customer base than ENSTAR, has recently requested $1.5 million in rate case expense to support a rate case that involves fewer parties than the instant proceeding.[459]

Titan presented testimony that ENSTAR's rate cases have occurred on an average every 5.33 years.[460] At hearing, ENSTAR referred to an expected three to five years between rate cases.[461]

The amount of rate case expense that we include in the revenue requirement is an estimate of future rate case cost, not the recovery of past rate case expenditures.[462] We generally believe that it is not desirable to base the allowance on a post-hearing calculation of actual rate case costs incurred.[463] Current experience is relevant and may indicate trends that costs will differ from past experience.[464]

Allowing rate case expense in the revenue requirement is not intended to allow a utility to fully recover expenses associated with specific past cases. We deny ENSTAR's request to include $129,680 in annual amortization expense associated with its last rate case, Docket U-14-111, in its current revenue requirement.

We find ENSTAR's arguments in support of its request for $1.8 million in rate case expense on a going forward basis persuasive and consistent with our recent

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[458] T-11 (Dieckgraeff Reply) at 51-52.

[459] T-11 (Dieckgraeff Reply) at 52 (citing Docket U-17-008).

[460] T-17 (Britton) at 12-13.

[461] Tr. 2057, 2349, 2470 (Dieckgraeff).

[462] Order U-00-088(12) at 24.

[463] Order U-90-090(7) at 9.

[464] Order U-90-090(7) at 9.

experience. However, we require ENSTAR to amortize the expense over five years, rather than the requested three years. The five year amortization is consistent with the time-frame articulated in testimony. And as part of our decision in this docket we are requiring ENSTAR to file a new rate case in five years, based on a 2020 test year. Rate case expense is not intended to represent a post-hearing calculation of actual rate case costs. Therefore, we will not require ENSTAR to true up its actual expenses.

Customer Usage and Normalized Weather

The AG proposes to adjust test year gas sales because the 2015 test year was "warmer than normal."[465] The AG states that because the test year was warmer than normal, sales of gas relating to weather-sensitive uses, such as space heating, reflect lower sales levels than would be expected under normal weather conditions.[466] To reach the determination that 2015 was warmer than normal, the AG reviewed heating degree day (HDD) information from the National Oceanic and Atmospheric Administration (NOAA) that was provided by ENSTAR in discovery.[467] The AG compared the NOAA HDD information for 2015 for the months of January through May and September through December to HDD averages on a five, ten, 15, 20, and 30-year basis.[468] The HDD for the test year ranged from 91.99% of the 15-year average to 93.73% of the 5-year average.[469] The AG states that it is becoming more widely acknowledged that the earth is experiencing a global warming trend.[470] The AG recommends normalizing weather

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[465] T-15 (Smith) at 21.

[466] T-15 (Smith) at 21.

[467] T-15 (Smith) at 20-21, Exhibit RCS-13.

[468] T-15 (Smith) at 27.

[469] T-15 (Smith) at 27.

[470] T-15 (Smith) at 28-29.

based on the 20-year average HDD in part to avoid understating the impact of the global warming trend.[471]

Titan also recommends a weather normalization adjustment to ENSTAR's volumes.[472] Titan argues that 2015 was extraordinarily warm due in large part to the periodic El Niño weather pattern.[473] Titan compares the test year HDD to the 20-year average and recommends a 10% increase to ENSTAR's demand volumes.[474]

In reply testimony, ENSTAR questioned whether the 20-year average in HDD can be considered normal given "climate change and demonstrable trends of warming in arctic regions including three consecutive record low levels of arctic ice pack range."[475] ENSTAR asserts that Titan's claim that El Niño climate influence has ceased is contradicted by current climate reports.[476] ENSTAR also notes that the five-year average HDD (2012-2016) of 9,544 is close to the test year level of 9,111 (95.46%).[477]

We provided guidance for proposed weather normalization adjustments in Order U-01-108(26). In that proceeding, we denied intervenor proposed weather normalization adjustments to Chugach test year loads.[478] We stated:

> Any proposed adjustment to normalize historical weather data must be reasonable, measurable, and must adequately address the following two issues. First, it must clearly demonstrate that the test year was a climatic anomaly where temperature departed significantly from the normal range of

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[471] T-15 (Smith) at 28-29.

[472] T-17 (Britton) at 13-16.

[473] T-17 (Britton) at 15.

[474] T-17 (Britton) at 15-16.

[475] T-11 (Dieckgraeff Reply) at 75.

[476] T-11 (Dieckgraeff Reply) at 76.

[477] T-11 (Dieckgraeff Reply) at 76. ENSTAR used full year HDD totals. The five-year average used by the AG was seasonal and from 2011-2015. T-15 (Smith) at 27.

[478] Order U-01-108(26) at 34-36.

> temperature fluctuations. Second, it must clearly demonstrate how this anomaly correlates to the power sales.[479]

With the global warming trends recognized by the AG and ENSTAR, and noting that the test year HDD is 95.46% of the most recent five-year average, we find that the AG and Titan have not clearly demonstrated that the test year was a climatic anomaly where temperature departed significantly from the normal range of temperature fluctuations. We decline to require a weather adjustment to ENSTAR's test year volumes.

Power Plant Volumes and Economy Energy Sales

ENSTAR proposed adjustments for volumes and revenue to account for changes in the level of transportation service provided to MEA's EGS, the Southcentral Power Project (SPP) (jointly owned by Chugach and ML&P), and ML&P's Plant 2A.[480] EGS began operation during 2015.[481] Before EGS began operation, MEA received the bulk of its power needs from Chugach.[482] SPP was partially used to supply MEA with power before May 1, 2015.[483]

ENSTAR provides transportation service to EGS and SPP under its Very Large Firm Transportation (VLFT) rate schedule.[484] After discussions with Chugach and MEA, ENSTAR determined that the period of May 1, 2015, to April 30, 2016, would be most representative of the expected load for EGS and SPP.[485] ENSTAR also adjusted projected volumes and revenues from ML&P downward based on the "significant natural

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[479] Order U-01-108(26) at 35.

[480] T-8 (Fairchild Direct) at 9-10; H-1, Revenue Requirement at Schedule C.

[481] T-10 (Dieckgraeff Direct) at 25.

[482] T-10 (Dieckgraeff Direct) at 25.

[483] T-8 (Fairchild Direct) at 9-10; T-10 (Dieckgraeff Direct) at 25.

[484] T-10 (Dieckgraeff Direct) at 26.

[485] T-8 (Fairchild Direct) at 9-10; T-10 (Dieckgraeff Direct) at 25.

gas savings" anticipated from ML&P's new generation Plant 2A, which was scheduled to come on-line in late summer or fall 2016.[486]

The schedule reflecting these adjustments also removed volumes related to economy energy sales by the power plant customers.[487] Economy energy sales as the term is used during this proceeding refers to transportation of gas volumes for power utilities to use and sell excess electricity to others.[488] The removal of economy energy volumes was disputed during this proceeding. The other adjustments were not disputed in testimony by the power plant customers.[489] ENSTAR asserted that it will be adversely affected if reductions in volume resulting from economic dispatch efforts are not taken into account during this proceeding.[490]

Titan asserts that the removal of economy energy volumes is not a known and measurable adjustment.[491] Titan states that the complete elimination of a category of sales that occurred in the test year, continued following the test year, and is expected to continue in the future is not justified.[492] At hearing, Titan introduced exhibits during cross-examination intended to show that overall transportation volumes on ENSTAR's

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[486] T-10 (Dieckgraeff Direct) at 26. *See also* Docket U-17-008, which is ML&P's revenue requirement and request for rate increases based primarily on the cost associated with Plant 2A.

[487] H-1, Revenue Requirement at Schedule C.

[488] Tr. 2309, 2318-19 (Dieckgraeff).

[489] Titan presented testimony that "[d]ue to the changes in the generating facilities, some adjustment to historical volumes may be appropriate." T-17 (Britton). However, in post–hearing briefing Titan argued against the adjustments. Titan Post-Hearing Briefing at 11-14.

[490] T-10 (Dieckgraeff Direct) at 27.

[491] T-17 (Britton) at 15-16.

[492] T-17 (Britton) at 16.

system have increased, rather than decreased since the test year.[493] Titan did not present testimony challenging ENSTAR's other volume adjustments, but argued that there should be an adjustment to increase volumes based on data from May 2016 through April 2017.

HEA asserts that there is every indication that economy energy sales will continue into the future.[494] HEA states that Chugach and ML&P provided ENSTAR with estimates of future gas volumes that are associated with economy energy sales.[495] HEA asserts that the estimates are the same as those used by ENSTAR to make the other adjustments for power plant volumes and revenues.[496] In prefiled testimony, HEA stated that we should require ENSTAR to utilize at least the forecasted volumes of economy energy sales gas in its adjustment and re-calculate rates accordingly.[497] In argument, however, HEA advocated in favor of reversing ENSTAR's elimination of economy energy sales volumes.[498]

Chugach and ML&P did not present testimony challenging ENSTAR's removal of economy energy volumes. However, Chugach engaged in cross-examination and argued that ENSTAR recovers twice for the revenues it makes from economy energy sales.[499] Chugach and ML&P argued that ENSTAR should propose a mechanism to

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[493] H-58; H-59.

[494] T-22 (Salzetti) at 19.

[495] T-22 (Salzetti) at 19.

[496] T-22 (Salzetti) at 19.

[497] T-22 (Salzetti) at 19.

[498] HEA Post-Hearing Brief at 25-26.

[499] Tr. 2312-22 (Dieckgraeff).

refund or reimburse ENSTAR customers for revenues received from the transportation of gas used for economy energy sales.[500]

At hearing, witnesses for the AG stated that it was an oversight in their pre-filed testimony not to have put in volumes for economy energy sales.[501]

ENSTAR asserted that the level of economy energy sales provided on its system has been erratic and unpredictable.[502] ENSTAR states that the level of future sales cannot be reasonably anticipated and is not known or measurable with any degree of certainty.[503] Therefore, ENSTAR did not include these sales.[504] ENSTAR dismisses HEA's suggestion that it include forecasted volumes asserting that the adjustment would not follow the requirement of being known and measurable.[505]

ENSTAR stated at hearing that it removed the economy energy sales in light of all the other changes that were anticipated with the power customers.[506] ENSTAR asserted that economy energy sales are expected to dramatically decrease once Golden Valley Electric Association, Inc.'s (GVEA) Healy plant once again becomes fully operational.[507] ENSTAR stated that there has been a delay in expected volume decreases largely due to problems in getting the GVEA Healy plant back online, ML&P's Plant 2A not being fully operational, and delays in finalizing the Anchorage power pool.[508]

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[500] Chugach Post-Hearing Brief at 8-10; ML&P Post-Hearing Brief at 2.

[501] Tr. 1563 (Smith); Tr. 2970-71 (Fairchild-Hamilton).

[502] T-11 (Dieckgraeff Reply) at 72.

[503] T-11 (Dieckgraeff Reply) at 72.

[504] T-11 (Dieckgraeff Reply) at 72-73.

[505] T-11 (Dieckgraeff Reply) at 73-74.

[506] Tr. 2472 (Dieckgraeff).

[507] Tr. 1292 (Fairchild); Tr. 2097, 2480-81 (Dieckgraeff explaining two explosions have taken the plant offline).

[508] Tr. 1294-95 (Fairchild); Tr. 2096-98 (Dieckgraeff).

ENSTAR asserts that when these changes take effect they will “pretty much offset the economy energy volumes” experienced during the test year.[509]

ENSTAR states that, with some exceptions, power customers do not normally identify to ENSTAR that gas is being transported to generate power for economy energy sales.[510] ENSTAR stated that at one time it had a separate rate for volumes associated with economy energy sales.[511] However, ENSTAR asserted that there was a great deal of difficulty ensuring that the volumes transported were in fact for economy energy sales and there was some alleged gaming going on.[512] ENSTAR stated that it would be willing to accept some type of adjustment mechanism to keep it whole for all power volumes.[513]

We find that ENSTAR’s testimony that it adjusted power customer volumes and revenues generally credible and the adjustment reasonable. However, ENSTAR continued to transport volumes associated with economy energy sales in 2016 and 2017[514] and given our understanding of these sales we believe that they are likely to continue. It is not appropriate to completely eliminate these volumes simply because they are variable in nature. We require ENSTAR to reverse its removal of economy energy volumes from its normalized power customer volume and revenue adjustment.

Cost Allocation and Rate Design

Integrated System

In Order U-83-038(6), we explicitly stated:

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[509] Tr. 2319 (Dieckgraeff).

[510] Tr. 2319 (Dieckgraeff).

[511] Tr. 2322 (Dieckgraeff).

[512] Tr. 2322 (Dieckgraeff).

[513] Tr. 2322 (Dieckgraeff).

[514] Tr. 2017 (Dieckgraeff).

> As a foundation for certain conclusions which follow in this Order, the Commission hereby finds that ENSTAR's production, gathering, transmission and distribution plant is most appropriately categorized for COS [cost-of-service] and rate design purposes as a fully integrated natural gas delivery system. The Commission concurs with both Staff and ENSTAR that the plant used for the delivery of gas to all customers is so thoroughly interdependent that efforts to isolate specific portions of the system which serve particular customers is not only impractical, but attempts to do so will produce inappropriate distortions in a COS study. While recognizing that certain types of plant may be of greater direct benefit to a single class of customers, the Commission finds the following evidence supports the conclusion that the power customers should share in costs of the distribution system: testimony shows that the ENSTAR system is functionally designed and operated as an integrated delivery network; a customer need not be directly or physically connected to a unit of plant in order to benefit from its existence; plant enhancements to physically discrete segments of the ENSTAR system have resulted over time in a superior overall system from the standpoint of reliability and economic efficiency; and all classes of customers have benefitted from ENSTAR's integrated design approach and, therefore, must share in the costs.[515]

Testimony to the same effect as that referred to in our finding above was presented in this proceeding.

ENSTAR states that its system is functionally designed and operated as an integrated delivery network.[516] ENSTAR asserts that a customer does not need to be directly or physically connected to any given piece of plant in order to benefit from its existence.[517] ENSTAR claims that the integrated system provides access to economies of scale, access to diverse gas supplies, system support, and gas balancing.[518] ENSTAR asserts that higher capacity on one pipeline segment may reduce the likelihood that gas will be curtailed on other segments.[519] The ENSTAR pipeline system connects with the Hilcorp (Harvest Alaska) Kenai Beluga Pipeline (KBPL) at several points, forming a

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[515] Order U-83-038(6) at 3-4.

[516] T-11 (Dieckgraeff Reply) at 77; T-9 (Fairchild Reply) at 35-36.

[517] T-11 (Dieckgraeff Reply) at 77; T-9 (Fairchild Reply) at 35-36.

[518] T-11 (Dieckgraeff Reply) at 78.

[519] T-11 (Dieckgraeff Reply) at 78.

complete loop around both sides of Cook Inlet.[520] ENSTAR states that the integrated nature of ENSTAR's and Hilcorp's combined system around the Cook Inlet enhances reliability for all customers.[521] ENSTAR states "ENSTAR's and KBPL's systems are integrated and benefit customers located along the pipelines, all the way around Cook Inlet."[522] ENSTAR asserts that the nature of the system allows customers to purchase gas on an emergency basis if needed.[523] ENSTAR also asserts that the integrated nature of the system allows customers to receive gas by displacement.[524]

The AG states that ENSTAR plant used for the transportation of gas to all customers is so thoroughly interdependent that efforts to isolate specific portions of the system that serve particular customers is not only impractical, but will produce inappropriate distortions in the COSS.[525] The AG referenced Order U-87-002(4)/ U-87-042(2) for the proposition that "a customer need not be directly or physically connected to a unit of plant in order to benefit from its existence," and "all classes of customers have benefitted from ENSTAR's integrated design approach and, therefore, must share in costs."[526] The AG presented testimony at hearing that ENSTAR has an integrated system and the gas can flow in a variety of different ways in order to reach the end use customers and serve their needs.[527]

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[520] T-11 (Dieckgraeff Reply) at 78.

[521] T-11 (Dieckgraeff Reply) at 78.

[522] T-10 (Dieckgraeff Direct) at 40.

[523] Tr. 2506-07 (Dieckgraeff).

[524] Tr. 1143-45 (Fairchild); Tr. 2038 (Dieckgraeff).

[525] T-15 (Smith) at 78.

[526] T-15 (Smith) at 78 (referencing Order U-87-002(4)/U-87-042(2) at 9).

[527] Tr. 1450 (Smith).

Chugach presented testimony that ENSTAR is an integrated system that is designed to achieve maximum efficiency and reliability at a minimum cost on a system-wide basis.[528] Chugach asserts that all customers benefit from the integrated system.[529] Chugach agrees the integrated nature of the ENSTAR system allows customers to receive gas by displacement.[530]

The record in this docket demonstrates that the ENSTAR system is functionally designed and operated as an integrated system. Customers need not be directly or physically connected to a unit of plant in order to benefit from its existence. The integrated nature of the ENSTAR system results in a superior overall system from the standpoint of reliability and economic efficiency. All classes of customers benefit from the integrated system and, therefore, must share in the costs.

Seaboard vs. Peak-Demand

In its COSS, ENSTAR proposes the use of the *Seaboard*[531] method to apportion most of its capacity-related costs, which are primarily related to ENSTAR's transmission activities.[532] The *Seaboard* method apportions costs between customer classes using an allocation factor calculated by weighting equally the relative contributions of each customer class to the test year coincident system peak demand and average day demand (equivalent of volumes).[533]

ENSTAR and the AG presented testimony in favor of the use of the *Seaboard* allocator. The intervenors, other than the AG, argued vigorously against use of the *Seaboard* method and in favor of a peak-demand method. For sake of

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[528] T-24 (Miller) at 8.

[529] T-24 (Miller) at 8.

[530] Tr. 3043 (Miller).

[531] *Atlantic Seaboard Corp.*, 11 F.P.C. 43 (1952).

[532] T-8 (Fairchild Direct) at 26.

[533] T-8 (Fairchild Direct) at 26.

administrative efficiency, and in recognition of the timelines that our decision must be issued under, we will not recite all of the arguments presented for and against use of the *Seaboard* method. However, all were considered in our decision. A representative sample follows.

ENSTAR asserts that it uses the *Seaboard* allocation factor reflecting both coincident peak demand and average day demand because its transmission facilities are intended to meet customers' demands on peak days and also provide access to gas supplies.[534] ENSTAR has proposed the use of the *Seaboard* method in every rate case since we adopted the approach in Order U-87-002(4)/U-87-042(2).[535]

The AG states that the *Seaboard* allocation factor is the most appropriate allocation factor for ENSTAR to use for its transmission costs because a peak-demand only factor does not properly assign costs to cost causers. The AG states that ENSTAR's transmission system is designed to meet the uninterrupted peak demand of firm service customers and to access gas supplies.[536] The AG also states that the transmission system provides a commodity function by providing access to gas supplies around the Cook Inlet.[537] The AG states that a major function of ENSTAR is to connect the system to gas supply.[538] The AG asserts that use of the *Seaboard* allocator recognizes ENSTAR's dual functions of accessing gas supplies and meeting peak demand.[539] The

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[534] T-8 (Fairchild Direct) at 26.

[535] T-8 (Fairchild Direct) at 26; Tr. 1028; Order U-87-002(4)/U-87-042(2) at 6.

[536] Tr. 1517-1518.

[537] T-15 (Smith) at 79.

[538] Tr. 1518 (Smith).

[539] Tr. 1517 (Smith).

AG asserts that the ENSTAR integrated transmission and distribution system is fairly unique.[540]

ML&P asserts that the Federal Energy Regulatory Commission (FERC) moved to a "straight fixed variable" (SFV) method that uses peak demand to assign demand-related costs starting in 1992.[541] The SFV method is tied to firm gas contracts with estimated maximum volumes based on peak usage.[542] ML&P argues that customers contract for the maximum gas volumes they believe they will need transported, not half of the volumes or their average volumes.[543] ML&P states that the FERC refers to that maximum volume amount when using the SFV method.[544]

Chugach stated that most jurisdictions rejected the *Seaboard* method because it caused market distortions thirty years ago in the natural gas markets nationwide.[545] Chugach argues that ENSTAR's testimony that it has not interrupted service to its firm transportation customers in the last 20 years shows there is no current concern about curtailments of peak supply.[546]

In Order U-87-002(4) we approved the use of the *Seaboard* allocation method over the intervenors' arguments that a peak-demand method for allocating transmission plant was preferable. In doing so we recognized that ENSTAR's system was designed to access gas supplies and meet peak loads, a fact recognized by the *Seaboard* method. We acknowledge the intervenors' arguments that the FERC has

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[540] Tr. 1449 (Smith).

[541] T-25 (Daniel) at 15-17.

[542] T-25 (Daniel) at 15-17.

[543] T-25 (Daniel) at 15-17.

[544] T-25 (Daniel) at 15-17.

[545] T-23 (Peterson) at 14.

[546] T-23 (Peterson) 14-15; T-25 (Daniel) 11-17.

utilized a peak-demand allocation method since 1992. However, FERC regulates interstate transmission pipelines. ENSTAR is an integrated transmission and distribution utility that is not really analogous to a FERC-regulated gas transmission pipeline.[547] We believe that use of the *Seaboard* allocation method best recognizes the unique nature of the ENSTAR system and the fact that it is designed and operated to meet both peak-demand and also provide access to gas supplies.

Allocation of the Anchor Point Pipeline

The Anchor Point Pipeline (APPL) is a 20 mile, 8-inch pipeline connecting Ninilchik and Anchor Point that was placed into service in March 2011.[548] HEA and Titan argue against the inclusion of the costs of the APPL in their rates.

HEA asserts that the primary driver for ENSTAR to build the APPL was to provide a means for transporting system supply gas to gas sales customers.[549] HEA states that in a stipulation reached in Dockets U-09-069/U-09-070, ENSTAR agreed to recover the cost of service associated with the APPL from gas sales customers.[550] HEA does not take issue with the continued recovery of the costs from gas sales customers, but does oppose the inclusion of the APPL costs in rates for transportation-only customers.[551] HEA opposes the inclusion of the costs in rates for transportation customers because (1) ENSTAR's stated purpose for the APPL was to provide service to the gas sales distribution load and (2) the APPL is physically remote from the rest of the

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[547] *See e.g.* Tr. 1371 (Smith).

[548] T-22 (Salzetti) at 13.

[549] T-22 (Salzetti) at 13.

[550] T-22 (Salzetti) at 14; *see* Order U-09-069(10)/U-09-070(10), *Order Accepting Stipulation, Vacating Hearing Dates, and Approving Tariff Sheets*, dated August 9, 2010, Appendix at 7-8.

[551] T-22 (Salzetti) at 14.

ENSTAR system and is only accessible through the pipeline facilities of a third-party, few of the transportation requirements of ENSTAR's customers can be physically served off the APPL, and little has changed since the stipulation reached in Dockets U-09-069/ U-09-070.[552] HEA requests that we require ENSTAR to continue to allocate 100% of the costs of the APPL to distribution customers, or require ENSTAR to develop an incremental rate or surcharge that would be paid by those that use the APPL.[553]

Titan argues that it has never shipped gas over the APPL and allocation of the expenses of the line to Titan is unfair.[554] Titan argues that ENSTAR does not operate an integrated system because the APPL is not connected to the rest of ENSTAR's system.[555]

Chugach advocates against segmented or "non-postage stamp" rates on the ENSTAR system.[556] Chugach states that it is well-established in our precedent and policies that postage stamp rates strike a fair balance for all customers who receive a benefit from the pipeline system.[557] Chugach states that an integrated system is designed to achieve maximum efficiency and reliability at a minimum cost on a system-wide basis.[558] Chugach asserts that all customers benefit from the integrated system and should appropriately share in all costs of the integrated system.[559]

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[552] T-22 (Salzetti) at 14-15.

[553] T-22 (Salzetti) at 15-16.

[554] T-17 (Britton) at 11.

[555] T-17 (Britton) at 11.

[556] T-24 (Miller) at 8.

[557] T-24 (Miller) at 8.

[558] T-24 (Miller) at 8.

[559] T-24 (Miller) at 8.

ENSTAR states that Cook Inlet Energy (CIE), as an ENSTAR transportation customer, has shipped gas on APPL for sale to HEA since early 2014.[560] ENSTAR also states that HEA added an APPL receipt point to its transportation service agreement with ENSTAR and shipped volumes on APPL in 2015 and 2016.[561]

ENSTAR states that Hilcorp and BlueCrest Energy also have production connected to the APPL for transportation to their customers.[562] Titan purchases gas for its liquefied natural gas (LNG) plant under a contract with Hilcorp.[563] The contract states that Hilcorp may deliver gas to any delivery point on ENSTAR's system.[564]

The stipulation that we accepted in Order U-09-069(10)/U-09-070(10) initially allocated APPL costs to gas sales customers, because ENSTAR would be the only initial shipper on the pipeline and transportation customers would not be using it during the rate-effective period.[565] The provision in the settlement does not address the cost allocation of the APPL in future proceedings.[566]

As we stated above, all classes of customers benefit from the integrated system and must share in its costs, regardless of whether they are directly or physically connected to a unit of plant. Further, the record demonstrates that HEA receives gas transported over the APPL and itself transports volumes on APPL. The record also demonstrates that Titan's gas supplier may deliver gas to any delivery point on the ENSTAR system, including on APPL. HEA and Titan benefit from the ENSTAR integrated

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[560] T-10 (Dieckgraeff Direct) at 41.

[561] T-10 (Dieckgraeff Direct) at 41; T-11 (Dieckgraeff Reply) at 80; H-50.

[562] T-11 (Dieckgraeff Reply) at 81.

[563] T-17 (Britton) at 4; H-69.

[564] Tr. 1697 (Britton); H-69 at 35.

[565] Order U-09-069(10)/U-09-070(10), Appendix at 7-8.

[566] Order U-09-069(10)/U-09-070(10), Appendix at 7-8.

system and specifically benefit from APPL. We decline to remove the costs of APPL from the rates for HEA and Titan.

Lateral to Access CINGSA

Similar to the discussion related to the APPL, Titan and HEA argue that they should not be allocated costs of the lateral to access CINGSA. Given our finding regarding the integrated nature of the ENSTAR system above, we succinctly identify the arguments and address the matter as follows.

Titan states that it does not use the CINGSA facility and argues that the cost to connect ENSTAR's system to the storage facility should not be allocated to transmission customers who do not use the storage facility.[567] HEA argued primarily that the decision to construct the lateral was not prudent, which we addressed above.

Testimony in the docket established that Titan benefits from the additional pressure and capacity that the lateral creates for the entire ENSTAR system[568] and that HEA used the lateral to access CINGSA in 2016 and continues to use the lateral.[569]

All classes of customers benefit from the integrated system and must share in its costs, regardless of whether they are directly or physically connected to a unit of plant. We decline to remove the costs of the lateral from the rates for Titan and HEA.

Other Allocations to Transportation Customers

Distribution Plant, Bad Debt Expense

In reply testimony ENSTAR conceded that it would remove distribution plant from assignment to the MSFT class and remove bad debt expense from the MSFT, VLFT, and ITT/ITS classes if directed by us.[570] We order ENSTAR to remove distribution plant

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[567] T-17 (Britton) at 12.

[568] Tr. 1143-1149 (Fairchild).

[569] H-131; H-132.

[570] T-9 (Fairchild Reply) at 37-39.

from assignment to the MSFT class and remove bad debt expense from the MSFT, VLFT, and ITT/ITS classes.

Purchased Gas Expense

Titan states that the COSS allocates a portion of ENSTAR's purchased gas expenses to Titan and other transmission-only customers. Titan argues that because it does not purchase gas from ENSTAR, it should not be allocated any of this expense.[571]

Titan, along with HEA, receives service from ENSTAR under the MSFT service tariff.[572] ENSTAR asserts that whether or not Titan uses or benefits directly from purchased gas expenses, the other member of the MSFT rate class (HEA), does. ENSTAR states that the allocation of the expenses to the MSFT rate class is appropriate.[573]

We find that ENSTAR appropriately allocated a portion of purchased gas expense to the MSFT class.

Customer Meter Weightings

ENSTAR used a value of $75,000 for the meter weighting factor for the MSFT customers.[574] HEA argues that this is higher than the actual value of $61,050, which results in a higher weighting factor for HEA and Titan.[575] HEA asserts that the $75,000 is a random value and its use incorrectly allocates more expenses to the MSFT rate class than is appropriate.[576]

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[571] T-17 (Britton) at 10-11.

[572] ENSTAR Tariff Sheet No. 212.

[573] T-9 (Fairchild Reply) at 38.

[574] T-22 (Salzetti) at 17.

[575] T-22 (Salzetti) at 17-18.

[576] T-22 (Salzetti) at 17-18.

ENSTAR asserts that the use of typical meter costs is set in the 1989 NARUC Gas Distribution Rate Design Manual.[577] ENSTAR states that estimated meter costs are used for all customer classes rather than historical costs, therefore, ENSTAR asserts there is no reason to believe the MSFT class is being allocated a disproportionate share of customer-related costs in the COSS.[578]

We find that ENSTAR has appropriately determined meter weighting factors for the COSS in accordance with NARUC guidelines.

General Plant

ML&P states that functionalizing a utility's costs is the initial step in developing a COSS.[579] Cost functionalization categorizes all of a utility's costs into their primary functions.[580] ML&P states that ENSTAR's primary functions include production/gathering, transmission, distribution, customer accounting, and sales.[581] Most costs are directly functionalized on the utility's books and records using the FERC uniform system of accounts.[582] However, some costs cannot be directly assigned and must be assigned to functions using functionalization factors.[583] Two costs challenged by ML&P that are assigned using functionalization factors are general plant and administrative and general (A&G) expenses.[584]

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[577] T-9 (Fairchild Reply) at 41; BHF-2 at 2; H-61 at 33.

[578] T-9 (Fairchild Reply) at 41.

[579] T-25 (Daniel) at 22.

[580] T-25 (Daniel) at 22.

[581] T-25 (Daniel) at 22.

[582] T-25 (Daniel) at 22.

[583] T-25 (Daniel) at 22.

[584] T-25 (Daniel) at 22-28.

General plant includes office buildings, office furniture, transportation equipment, tools, laboratory equipment, communications equipment, and other plant not includible in other functional plant accounts.[585] ENSTAR functionalized general plant to the production/gathering, transmission, and distribution functions on the basis of gross plant investment.[586] ML&P stated, "if transmission gross plant is 40% of the total production/gathering, transmission and distribution gross plant then ENSTAR has assigned 40% of general plant costs to the transmission function."[587] The 40% of general plant costs are then allocated to customer classes similar to how transmission plant related costs are allocated by ENSTAR.[588] ML&P asserts that general plant related costs are not driven by gross plant and, therefore, functionalization based on gross plant produces an unreasonable result.[589]

ML&P states that this issue is important in the development of gas transportation rates because ENSTAR determines rates for all customers with a consolidated COSS, meaning pipeline costs are combined with local distribution costs.[590] ML&P asserts that ENSTAR as a local distribution company maintains a large customer accounting and service department to "accommodate the approximately 137,000 customers of the LDC system."[591] The smaller number of transportation customers requires fewer customer accounting and service personnel.[592] ML&P states that no

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[585] T-25 (Daniel) at 23.

[586] T-25 (Daniel) at 23.

[587] T-25 (Daniel) at 23.

[588] T-25 (Daniel) at 23.

[589] T-25 (Daniel) at 24.

[590] T-25 (Daniel) at 24.

[591] T-25 (Daniel) at 25.

[592] T-25 (Daniel) at 25; Tr. 2846-47 (Fairchild).

general plant is assigned to the customer accounting and service function, which would have been almost entirely allocated to the LDC customers.[593] ENSTAR agrees that this is correct as there is no real plant in the customer accounting function.[594] ML&P argues the result is an over-allocation of general plant costs to the pipeline transportation customer classes.[595]

ML&P recognizes that functionalization by gross plant is one method that can be utilized but asserts that functionalization of general plant using payroll costs is "a much better method for functionalizing general plant related costs."[596] ML&P proposed payroll related functionalization factors using payroll costs using ENSTAR's FERC Form No. 2 for 2015 (the test year).[597] ML&P asserts that functionalizing general plant using a payroll functionalization factor is a commonly accepted methodology.[598]

ENSTAR responded by presenting testimony asserting that we already considered and rejected the approach to allocating general plant advocated by ML&P in Order U-87-002(4)/U-87-042(2).[599] At hearing, ENSTAR asserted that the gross plant functionalization method is the one contained in the NARUC 1981 Rate Design Manual and the NARUC 1989 Gas Distribution Rate Design Manual.[600] ENSTAR did agree that there are other functionalization methods that could be used, such as the one proposed

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[593] T-25 (Daniel) at 25.

[594] Tr. 2845-46 (Fairchild).

[595] T-25 (Daniel) at 25.

[596] T-25 (Daniel) at 24.

[597] T-25 (Daniel) at 25-26, Table 3.

[598] T-25 (Daniel) at 26.

[599] T-9 (Fairchild Reply) at 39-41.

[600] Tr. 2848 (Fairchild).

by ML&P.[601] ENSTAR agrees that the gross plant functionalization has the effect of allocating more costs to transportation customers and less to LDC customers than the payroll expense method, although ENSTAR also states that is not the intent behind the functionalization.[602]

In Order U-87-002(4)/U-87-042(2), we addressed an argument from the Department of Defense (DoD) that ENSTAR should allocate general plant using operation and maintenance expense, excluding purchased gas expense, rather than gross plant.[603] The DoD argued that O&M costs were a proxy for labor costs.[604] We approved ENSTAR's proposed allocation of general plant based on gross plant as "supported by the NARUC manual" while the alternative proposed by the DoD was not.[605] We agreed that while departures from the NARUC manual are appropriate if an alternate method is preferable, the DoD did not adequately justify its proposed approach.[606]

In the current proceeding, ML&P has proposed a functionalization based on payroll, rather than a proxy as proposed by the DoD in Dockets U-87-002 and U-87-042. ENSTAR and ML&P both concede that the functionalization method proposed by the other is acceptable, while advocating in favor of their proposed methodology. We find that functionalization of general plant using a gross plant allocator has the effect of over allocating general plant costs to ENSTAR's transportation customer classes. We find that functionalization of general plant using a payroll based functionalization factor, such as proposed by ML&P, is a better reflection of the utilization of general plant by ENSTAR.

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[601] Tr. 2847-48 (Fairchild).

[602] Tr. 2862 (Fairchild).

[603] Order U-87-002(4)/U-87-042(2) at 15-16.

[604] Order U-87-002(4)/U-87-042(2) at 15.

[605] Order U-87-002(4)/U-87-042(2) at 15.

[606] Order U-87-002(4)/U-87-042(2) at 15-16.

We find ML&P's argument in favor of functionalizing general plant utilizing a payroll functionalization factor persuasive and that ML&P has adequately justified its proposed approach. We require ENSTAR to use the payroll functionalization factors for general plant proposed by ML&P.[607]

<u>Administrative & General</u>

ML&P advocates for functionalizing A&G expenses using the same payroll based approach described above.[608] A&G expenses include items such as office supplies, outside services, property insurance, injuries and damages insurance, employee pensions and benefits, rents, and maintenance of general plant.[609] ENSTAR functionalizes these expenses using a factor based on a combination of functionalized O&M expenses and property taxes.[610] ML&P asserts that ENSTAR's functionalization of A&G expenses results in over-allocating costs to the transportation customer classes.[611] ML&P states that functionalizing A&G expenses using a payroll functionalization factor is a commonly accepted methodology.[612]

In reply testimony, ENSTAR asserted that we already considered and rejected the approach to allocating A&G expenses advocated by ML&P in Order U-87-002(4)/U-87-042(2).[613]

In Order U-87-002(4)/U-87-042(2), we addressed an argument from the DoD that ENSTAR should include ad valorem tax expense in the allocation factor for A&G

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[607] The functionalization percentages are presented in T-25 (Daniel) at 26, Table 3.

[608] T-25 (Daniel) at 26-28.

[609] T-25 (Daniel) at 27.

[610] T-25 (Daniel) at 26.

[611] T-25 (Daniel) at 27.

[612] T-25 (Daniel) at 28.

[613] T-9 (Fairchild Reply) at 39-41.

expenses.[614] The order makes no mention of any proposal to use a payroll-based functionalization for A&G expenses as advocated by ML&P in this proceeding. Similar to our discussion regarding general plant above, we find that ENSTAR's functionalization of A&G expenses results in the over allocation of A&G expenses to the transportation customer classes. We find that functionalization of A&G expenses using a payroll based functionalization factor is a more reasonable approach. We require ENSTAR to use the payroll functionalization factors for A&G expenses proposed by ML&P.[615]

Titan Rate

Titan operates an LNG plant at Point MacKenzie, and provides natural gas to its affiliate Fairbanks Natural Gas, LLC (FNG), for distribution to Fairbanks gas customers.[616] Titan states that it purchases gas at Beluga, and contracts with ENSTAR to transport the gas from Beluga to the LNG plant.[617] The Titan LNG plant is located at approximately mile 39 of the Beluga-Anchorage pipeline.[618] Titan asserts that it should receive a rate based on "those costs required to move Titan's gas supply for 39 miles through the BAP [Beluga-Anchorage pipeline] transmission line to Point McKenzie."[619] Titan's pre-filed testimony, cross-examination, and argument consistently advocated in favor of this position.

As one aspect of its argument Titan points to FERC regulations for interstate transmission pipelines and also rates set for the Trans Alaska Pipeline System (TAPS).[620]

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[614] Order U-87-002(4)/U-87-042(2) at 16-17.

[615] The functionalization percentages are presented in T-25 (Daniel) at 26, Table 3.

[616] T-17 (Britton) at 3.

[617] T-17 (Britton) at 4.

[618] T-17 (Britton) at 4.

[619] T-18 (Cliff) at 2-4; T-17 (Britton) at 2.

[620] T-17 (Britton) at 7-8.

However, testimony at hearing stated that ENSTAR's system is not analogous to a FERC-regulated gas transmission pipeline.[621] Similarly, rate setting for TAPS,[622] which stretches 800 miles from Prudhoe Bay to Valdez, is not analogous to rate setting for transmission service on the ENSTAR system.[623]

Titan has a firm transportation agreement with ENSTAR with a delivery point on the Royalty Pipeline, on the east side of the Cook Inlet.[624] Under its gas sales agreement with Hilcorp, Titan has delivery points on any part of the ENSTAR system.[625] Hilcorp, not Titan, has control over where the gas is delivered.[626] Further, in our discussion above we identified the record that supports a finding that all customers, including Titan benefit from the entire, integrated ENSTAR system, rather than one small section.

Additionally, we have previously addressed arguments similar to those raised by Titan in Order U-14-001(9).[627] We explicitly rejected the argument that a transmission customer who alleges it only uses a small portion of the transmission facilities should receive a reduced rate.[628] We reached this decision based on precedent stating:

> The adoption of "postage stamp" rates in a local interconnected area has long been in use by electric, gas and water utilities. The mere proximity of a customer to a utility's generating plant, substation, transmission line,

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[621] Tr. 1371 (Smith); Tr. 3032 (Miller).

[622] TAPS is regulated under AS 42.06, the Alaska Pipeline Act.

[623] ENSTAR is regulated under AS 42.05, the Alaska Public Utilities Act.

[624] H-68; Tr. 1695-96 (Britton); H-3, H-99 (maps showing the location of the Royalty Pipeline).

[625] H-69.

[626] Tr. 1704 (Britton).

[627] Order U-14-001(9) at 22-26.

[628] Order U-14-001(9) at 26.

> transformer bank, pressure station, well, water treatment plant, main water line, etc. has long been rejected as the prime consideration in establishing rates.[629]

In this docket, Titan argues that it should receive a reduced rate because it asserts that it only uses the first 39 miles of the Beluga-Anchorage pipeline on the west side of the Cook Inlet. The record does not support Titan's argument and it is denied.

Very Large Firm Transportation Rate Schedule Issues

ML&P

ENSTAR proposes to move ML&P from its existing individual rate to the VLFT service rate schedule.[630] MEA (EGS) and Chugach (SPP) are the other two locations served under the VLFT rate schedule.[631] ENSTAR states that ML&P's usage and load pattern are similar to that of the other two power plant locations and all three facilities should be served under the same rules with the same marginal rate.[632] ENSTAR asserts that ML&P's existing rate schedule is a holdover from when ENSTAR also supplied the gas for ML&P's power generating stations.[633] ENSTAR states that service under the VLFT requires a contracted peak demand, a commitment to a maximum peak demand on ENSTAR's system.[634] ENSTAR argues that to have this requirement on Chugach and MEA, but not ML&P for similar service, is unfair.[635] ENSTAR asserts that because the facilities share similar usage and load patterns they should be served under

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[629] Order U-14-001(9) at 26 (quoting Order U-71-021(4) at 7).

[630] T-10 (Dieckgraeff Direct) at 48.

[631] T-11 (Dieckgraeff Reply) at 90.

[632] T-11 (Dieckgraeff Reply) at 90.

[633] T-11 (Dieckgraeff Reply) at 90.

[634] T-11 (Dieckgraeff Reply) at 90.

[635] T-11 (Dieckgraeff Reply) at 90.

the same rules.[636] ENSTAR also proposes to eliminate the declining block structure in the existing VLFT rate schedule and replace it with a flat, or uniform, volumetric rate.[637] ENSTAR states that this will result in every Mcf moved under the VLFT rate schedule having the same marginal volumetric rate.[638]

ML&P presented testimony stating simply that it should remain on its own power plant rate until an Anchorage Power Pool is operational.[639] ML&P claims that because ENSTAR included ML&P with the VLFT in its COSS, rather than as a separate class for its power plant service, there is no basis to determine if ENSTAR's rate class consolidation proposal is reasonable.[640] ML&P argued that its unique transportation circumstances justify its current transportation rate schedule.[641] ML&P stated that it owns and operates three separate thermal power plants and has a 30% interest in SPP.[642] ML&P asserted that it coordinates and dispatches the operation of the plants and its hydroelectric resources to minimize the cost of production for its customers, including the overall cost of gas transportation.[643] ML&P stated that its current power plant rate schedule allows for the aggregation of its three power plants for purposes of

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[636] T-11 (Dieckgraeff Reply) at 90.

[637] T-10 (Dieckgraeff Direct) at 48.

[638] T-10 (Dieckgraeff Direct) at 48.

[639] T-25 (Daniel) at 21.

[640] T-25 (Daniel) at 21.

[641] ML&P Post-Hearing Brief at 9. In testimony addressing the proposed APFT ML&P asserted that "ENSTAR should not be able to unilaterally set contract demand amounts as it has done for ML&P" and "Additional terms are needed to specify how the dispatch of pool members' generation resources will be considered for ENSTAR's proposed billing on contract demand amounts." T-25 (Daniel) at 34.

[642] ML&P Post-Hearing Brief at 9.

[643] ML&P Post-Hearing Brief at 9.

transportation but the VLFT does not.[644] ML&P did not dispute ENSTAR's testimony that ML&P, MEA, and Chugach (SPP) share similar usage and load patterns.

We find, based on the similar usage and load patterns of ML&P and the other members of the VLFT rate class, it is reasonable for ENSTAR to move ML&P from its separate rate schedule to the VLFT.

Excess Demand Penalty

MEA presented testimony arguing that the excess demand penalty[645] associated with the VLFT rate schedule is substantial and that "[e]xcessive penalties create risk that can potentially distort efficient operations."[646] MEA does not propose a specific revision associated with this testimony. ENSTAR stated that the VLFT excess demand penalty has been in place since the tariff sheet first became effective in 2003.[647] ENSTAR asserts that the purpose of the excess demand penalty is to prevent users of the rate schedule from gaming the system by under-committing for contracted peak demand.[648]

We find that the excess demand penalty associated with the VLFT rate schedule is reasonable and no revision is necessary.

MEA EGS Dual Fuel Rate Discount

MEA's EGS utilizes an advanced dual fuel technology that operates primarily on natural gas, but in case of an interruption of the gas supply the plant can seamlessly switch to ultra-low sulfur diesel fuel.[649] MEA refers to the section of

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[644] ML&P Post-Hearing Brief at 9.

[645] *See* ENSTAR Tariff Sheet No. 214.

[646] T-20 (Wilson) at 17.

[647] T-11 (Dieckgraeff Reply) at 93.

[648] T-11 (Dieckgraeff Reply) at 93.

[649] T-19 (Izzo) at 6.

ENSTAR's tariff addressing interruption in the case of shortage or emergency,[650] and states that because it is able to use an alternative fuel it is ranked at a lower priority for curtailment than residential or commercial customers.[651] MEA describes the level of service it receives from ENSTAR as the "least firm, firm service."[652] MEA acknowledges that ENSTAR is required by its tariff to compensate a customer who is curtailed, but asserts that this is not the same as providing firm service.[653] MEA argues that ENSTAR should be required to revise its tariff to include a 20% discounted demand charge for "Contractual Priority 6 Shippers."[654]

ENSTAR testified that the firm transportation service provided to MEA is identical to that provided to the other customers in the VLFT class.[655] ENSTAR compares the argument presented by MEA to the argument for an interruptible rate discount[656] presented by the DoD in Docket U-83-038.[657] In Order U-83-038(6), we found that power customers were not "interruptible in the traditional sense" and "there is no foundation for the approval of a discounted interruptible tariff."[658]

MEA provided no evidence that the service it receives from ENSTAR is anything less than firm service, no evidence that the ENSTAR transmission facilities serving EGS are insufficient to meet the projected needs of the power plant, and no

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[650] ENSTAR Tariff Sheet No. 112-13, Section 1220.

[651] T-20 (Wilson) at 21-23.

[652] T-19 (Izzo) at 11.

[653] T-20 (Wilson) at 24-25.

[654] T-20 (Wilson) at 25-26.

[655] T-9 (Fairchild Reply) at 41-42.

[656] Order U-83-038(6) at 15.

[657] T-11 (Dieckgraeff Reply) at 88-89.

[658] Order U-83-038(6) at 15-16.

evidence that deliveries to EGS have been subjected to curtailment by ENSTAR. ENSTAR provided affirmative testimony that it has not interrupted or curtailed firm service to any power generation plant, except for planned maintenance or construction activities, since at least 1983.[659] We decline to require ENSTAR to revise its tariff to offer a reduced demand charge for "Contractual Priority 6 Shippers."

Proposed Anchorage Pool Firm Transportation Service

ENSTAR proposes a new Anchorage Pool Firm Transportation Service (APFT) rate schedule that is identical to its VLFT rate schedule with the following exceptions: (1) it is only available to locations that are part of the yet to be formed mutually-beneficial power pooling and joint dispatch arrangement for the Anchorage area (in whatever form that takes); (2) locations that elect to take service must enter into a new transportation service agreement that specifically references the APFT rate schedule; (3) an APFT customer will not be subject to excess demand penalty on a given day so long as the combined volumes for all APFT customers on that given day do not exceed the combined contract peak demand for all APFT customers; and (4) as with ENSTAR's other rate schedules, service to an APFT location is exclusive (it cannot also be served at the same time under a different rate schedule).[660] ENSTAR asserts that it is proposing the schedule as requested in conjunction with the effort by Chugach and ML&P to develop the Anchorage Pool, a mutually-beneficial power pooling and joint dispatch arrangement.[661] Of the three utilities working on development of the Anchorage Pool,

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[659] T-11 (Dieckgraeff Reply) at 89.

[660] T-10 (Dieckgraeff Direct) at 49.

[661] T-10 (Dieckgraeff Direct) at 48.

Chugach supports adoption of the APFT rate schedule while MEA and ML&P argue against approval of the rate schedule.[662]

The Anchorage Pool is still being developed by the pool members and the specifics on how it will operate are not known.[663] The technical procedures and processes necessary for effective power pooling are not finalized and upgrades to the participants' facilities are not completed.[664] Until the Anchorage Pool is further developed we have no basis to determine whether the proposed rate schedule is just and reasonable. We decline to consider the proposed APFT rate schedule until the Anchorage Power Pool is finalized.

Gradualism

ENSTAR proposes to modify the results of the COSS so that the rates for each class move toward cost, "but in a way that does not unduly burden any particular class."[665] ENSTAR describes its proposed approach as "gradualism."[666] To implement its proposed gradualism, ENSTAR used the following criteria: (1) no customer class's rates are decreased and (2) no customer class's rates are increased more than 50% above the system average increase, with any excess being distributed among the other classes in proportion to their respective costs of service.[667] As a result of ENSTAR's

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[662] T-24 (Miller) at 8; T-25 (Daniel) at 33-35; Tr. 230 (Pease).

[663] T-25 (Daniel) at 33-35; Tr. 230 (Pease).

[664] *See* Docket I-15-001, *Joint Filing on Efforts Towards Power Pooling and Joint Dispatch among Anchorage Municipal Light and Power, Chugach Electric Association, Inc., and Matanuska Electric Association, Inc., and Joint Informational Filing of Amended and Restated Power Pooling and Joint Dispatch Agreement*, filed January 30, 2017, at 2.

[665] T-8 (Fairchild Direct) at 29.

[666] T-8 (Fairchild Direct) at 29.

[667] T-8 (Fairchild Direct) at 29, BHF-2 at 1.

proposed gradualism, the rate increase for the VLFT and IIT/ITS rate classes is mitigated, while the rates for all other classes are proportionately increased.[668]

Often when a utility proposes a rate mitigation method, it does so by foregoing some portion of its revenue requirement. That is not the case in this docket. ENSTAR still proposes to collect its entire revenue requirement and adjusts the rate increases required to do so between its customer classes. ENSTAR did not adequately justify why the cross-subsidization that results from mitigating the increase to the VLFT and IIT/ITS rate classes at the expense of the remaining customer classes is not unduly discriminatory or preferential.[669] We deny the gradualism proposed by ENSTAR and require ENSTAR to develop rates based on the results of the COSS.

Regulatory and Corporate Structure of ENSTAR and APLC

During the course of this proceeding, various intervenors presented testimony and/or argument asserting that ENSTAR and APLC should be regulated as separate entities. However, the scope of this proceeding is determined by the tariff revisions filed by ENSTAR, and a collateral issue such as regulatory structure becomes relevant only to the extent necessary to determine whether the revised rates are lawful. We have determined the basis for just and reasonable rates without reaching this issue. Therefore, this argument is not appropriately addressed in the context of this docket.

Compliance Filings

We require ENSTAR to re-file its revenue requirement with supporting schedules, cost-of-service study, and revised tariff sheets consistent with our decisions in this order, and in Order U-16-066(15), as a compliance filing. ENSTAR shall also incorporate any concessions made during the course of this proceeding in its compliance

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[668] BHF-2 at 1.

[669] AS 42.05.431(a).

filing.[670] We allow the other parties the opportunity to file comment on ENSTAR's compliance filing.

New Rate Case

We require ENSTAR to file a rate case, including a lead-lag study, based on a calendar year 2020 test year by June 1, 2021.

Final Order

This order constitutes the final decision in this proceeding. This decision may be appealed within thirty days of this order in accordance with AS 22.10.020(d) and Alaska Rule of Appellate Procedure 602(a)(2). In addition to the appellate rights afforded by AS 22.10.020(d), a party has the right to file a petition for reconsideration in accordance with 3 AAC 48.105. If such a petition is filed, the time period for filing an appeal is tolled and then recalculated in accordance with Alaska Rule of Appellate Procedure 602(a)(2).

ORDER

THE COMMISSION FURTHER ORDERS:

1. By October 20, 2017, ENSTAR Natural Gas Company, a Division of SEMCO Energy, Inc. shall re-file its revenue requirement with supporting schedules, cost-of-service study, and revised tariff sheets consistent with our decisions in this order and in Order U-16-066(15), and incorporating any concessions made during the course of this proceeding, as a compliance filing in this docket.

2. The other parties to this proceeding may file comment on the compliance filing required by Ordering Paragraph No. 1 within two weeks of its filing.

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[670] *E.g.*, Concessions regarding SEMCO allocations. T-11 (Dieckgraeff Reply) at 71.

3. By June 1, 2021, ENSTAR Natural Gas Company, a Division of SEMCO Energy, Inc. shall file a rate case, including a lead-lag study, based on a calendar-year 2020 test year.

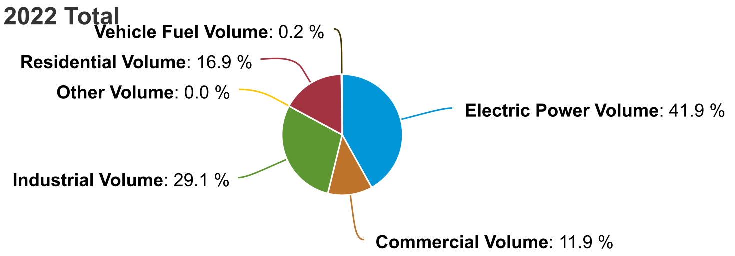
DATED AND EFFECTIVE at Anchorage, Alaska, this 22nd day of September, 2017.

BY DIRECTION OF THE COMMISSION

Natural Gas Annual Respondent Query System (EIA-176 Data through 2022)

Report: 176 Natural Gas Deliveries
Years: 2019 to 2022

Sort by: Area, Company, Item
Company: Show only Company Name



Release Date: September 2023 | **Next Release Date:** September 2024

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Form EIA-176 • User Guide • Definitions, Sources, & Notes

Area	Company	Item	2019	2020	2021	2022
U.S. Total	Total of All Companies	Residential Volume	5,018,518,521	4,674,456,169	4,716,658,154	4,964,16
U.S. Total	Total of All Companies	Commercial Volume	3,514,565,858	3,162,663,893	3,289,075,622	3,509,07
U.S. Total	Total of All Companies	Industrial Volume	8,416,660,208	8,212,977,100	8,374,672,351	8,536,88
U.S. Total	Total of All Companies	Electric Power Volume	11,596,874,362	11,510,407,146	11,341,637,439	12,309,50
U.S. Total	Total of All Companies	Vehicle Fuel Volume	50,789,707	46,875,819	52,334,019	63,81
U.S. Total	Total of All Companies	Other Volume	36,633	23,339	48,217	1
Alabama	Total of All Companies	Residential Volume	30,615,524	28,178,482	32,225,876	30,42
Alabama	Total of All Companies	Commercial Volume	24,874,649	22,905,919	25,711,053	25,77
Alabama	Total of All Companies	Industrial Volume	217,039,988	209,124,319	233,071,661	212,94
Alabama	Total of All Companies	Electric Power Volume	490,120,456	457,068,138	460,073,798	553,36
Alabama	Total of All Companies	Vehicle Fuel Volume	62,192	48,160	60,234	7
Alabama	Total of All Companies	Other Volume				
Alaska	Total of All Companies	Residential Volume	17,951,286	21,049,369	21,537,558	20,20
Alaska	Total of All Companies	Commercial Volume	14,569,840	16,598,361	16,816,861	16,05
Alaska	Total of All Companies	Industrial Volume	5,929,177	6,796,359	20,934,642	57,79
Alaska	Total of All Companies	Electric Power Volume	50,124,652	44,890,544	36,770,978	38,49
Arizona	Total of All Companies	Residential Volume	42,084,790	41,514,670	39,828,457	42,16
Arizona	Total of All Companies	Commercial Volume	34,686,520	31,604,891	33,278,934	35,63
Arizona	Total of All Companies	Industrial Volume	18,625,217	19,078,650	19,941,147	19,48
Arizona	Total of All Companies	Electric Power Volume	411,491,183	445,555,362	407,128,323	382,21
Arizona	Total of All Companies	Vehicle Fuel Volume	1,536,816	1,924,160	1,952,242	1,99
Arkansas	Total of All Companies	Residential Volume	33,718,397	30,302,018	33,841,231	31,36
Arkansas	Total of All Companies	Commercial Volume	55,099,970	52,697,142	57,060,888	55,31

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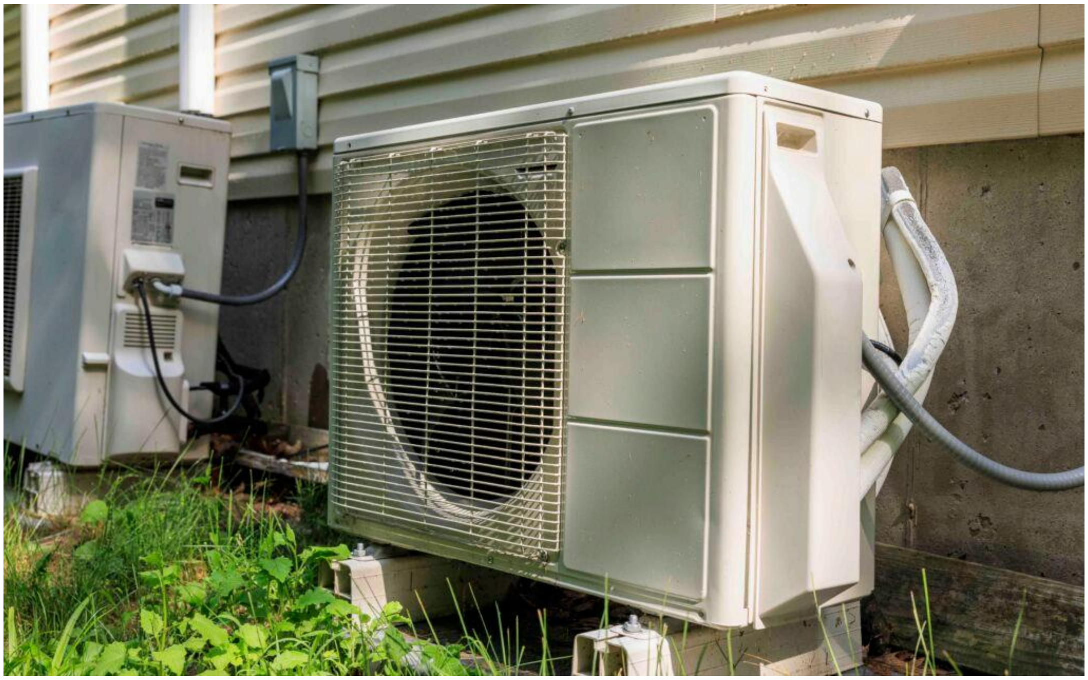
Washington makes another run at heat pump rules

Legal challenges could be on the horizon as critics say the new regulations, like a set scrapped in May, still don't comply with federal law.

BY: **JERRY CORNFIELD** - NOVEMBER 28, 2023 5:48 PM



Washington state regulators want builders to install electric heat pumps, like the one pictured above, in new homes. (Getty Images)

Controversial requirements aimed at getting electric heat pumps installed in newly constructed houses, apartments and commercial buildings cleared a final regulatory hurdle Tuesday.

The suite of changes, approved by the Washington State Building Code Council, is part of a broader effort by the state to slash carbon emissions and increase energy efficiency in residential and commercial construction.

The new rules will take effect March 15, 2024 barring unforeseen twists, such as legal roadblocks – which could arise.

The Building Code Council had approved new codes mandating the use of heat pumps in most new construction. But it paused them in May after a federal appeals court scrapped similar regulations in a California city, and as opponents to Washington's policy filed their own lawsuits. One of those cases remains pending in Thurston County Superior Court.

What the council enacted Tuesday offers builders incentives in the permitting process for choosing electric heat pumps – which provide both heating and cooling in the same unit – instead of natural gas furnaces. The appliances are more energy efficient and result in less pollution than gas furnaces.

But months of discussion culminating with Tuesday's four-hour meeting didn't end divisions over the heating technology or the council's regulatory undertaking.

Backers hailed the new codes as among the most climate and health friendly in the nation and said they would help to keep Washington on course to meet its goals paring greenhouse gas emissions from homes and commercial buildings.

"Ultra-efficient buildings powered by clean electricity in Washington state are a climate and public health imperative, and these energy codes use proven technology to get us there," said Rachel Koller, managing director of Shift Zero, in a statement. "The council's energy codes for new construction are a critical part of the solution to cleaner air for our communities."

Opponents warned the changes will result in higher costs for builders, home buyers and renters, and said they will put the state out of compliance with federal regulations.

"I find it's going to make things way too expensive," said Tom Handy, a Whitman County commissioner and council member. "I think it's going to hurt affordable housing. I think it's going to hurt small builders."

Turning the page

Tuesday's decision ends a turbulent chapter for the Building Code Council.

State lawmakers set a 2031 deadline for slashing greenhouse gas emissions from residential and commercial development by 70% below levels envisioned with the 2006 building codes.

It left the panel, composed primarily of contractors, laborers, and local government leaders, to make it happen. Electric heat pumps are cleaner and more energy efficient but aren't necessarily the appliance of choice for builders and homeowners.

The council ditched its earlier code changes due to questions about whether they complied with the federal Energy Policy and Conservation Act.

Their concern stemmed from the California case – California Restaurant Association v. City of Berkeley – in which the 9th U.S. Circuit Court of Appeals concluded the federal law "expressly preempts State and local regulations concerning the energy use of many natural gas appliances, including those used in household and restaurant kitchens."

While the version of Washington's codes the council had been moving ahead with didn't fully ban gas appliances, the panel opted to come up with a different approach to comply with the federal law. It still effectively steers builders to choose heat pumps.

Still a 'ban'

Washington's building code contains energy efficiency requirements for residential and commercial construction. It establishes a scoring system used in the approval of building permits based on the size of a dwelling unit or building and different construction options.

One of the biggest changes from May is the council erased language mandating heat pumps for heating water and rooms in homes. And it revised how credits that builders need to comply with the state building code are awarded under the scoring system in hopes of spurring greater use of low-carbon building solutions.

Different amounts of credits are available for installing various appliances and employing building treatments to reduce energy use. The credits are available for such things as heat pumps, solar panels, and upgraded thermostats or ventilation systems.

Under the new rules, a builder will need five credits for a home of less than 1,500 square feet. That's double the sum they need today. For a home between 1,500 and 5,000 square feet, they will need eight credits, up from five.

There are new credit values under the plan for different appliance options and building practices. Not surprisingly, more credits are awarded for use of an electric heat pump than a natural gas furnace.

The Building Industry Association of Washington, which challenged the earlier version of the codes, says the latest one may put the state at an even greater risk of running afoul of the federal law.

Greg Lane, BIAW's executive vice president, described the council's action as "a de facto ban on natural gas in new homes."

"These new rules clearly continue to violate the federal Energy Policy and Conservation Act, which expressly preempts state and local regulations concerning the energy use of many natural gas appliances," Lane said.

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WASHINGTON

Washington Senate committee advances natural gas bill

By: Black Chronicle News Service
February 17, 2024

(The Center Square) – A Washington State Senate committee has voted to advance House Bill 1589 that has implications for current and future natural gas customers in Puget Sound, while critics say the full costs to ratepayers and taxpayers needs further examination.

“It’s not looking at what the cost is going to be when it becomes fully implemented,” Rep. Drew MacEwen, R-Shelton, told colleagues at the Senate Environment, Energy & Technology’s Friday executive session. “That is a significant cost that will be borne by taxpayers across the state.”

MacEwen unsuccessfully sought to amend the bill so that the state Utilities and Transportation Commission would have to study the cost for large utility customers to switch from natural gas to clean electricity and report back to the Legislature.

He said that the bill’s fiscal note does not account for all the costs for the state and should be fixed in the Senate Ways & Means Committee.

Also speaking against the bill was Sen. Shelly Short, R-Addy, who told colleagues that “we’ve never peeled back the onion” regarding the bill’s true costs. “There are fundamental things that are being changed.”

In favor of the bill’s passage was Chair Joe Joe Nguyen, D-White Center, who sponsored a striking amendment making certain changes to the bill. However, among the provisions still remaining allows large utility providers to cease offering natural gas to existing customers and replace it with “any approved non-emitting energy” sources, which would include renewable natural gas.

“We as Washington state need to be partners in a thoughtful way in terms of achieving not just our climate goals but ensuring that our residents have the best options available to them,” Nguyen said. “We need to be able to have the flexibility to consider all the opportunities that are available to us.”

The revised bill is still opposed by the Building Industry Association of Washington. In a statement, BIAW Executive Vice President Greg Lane wrote that “legislators say they care about both housing costs and rental costs, but ignore the effects this bill will have on

Washingtc
pay higher
their gas a
electric appliances at costs more than $50,000 total. We continue to fight for the rights of natural gas customers in Washington.”

HB 1589 first cleared the House in a 52-45 vote. It has yet to be referred to another committee.