BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET UE-240006

DOCKET UG-240007

EXH. JCA-3

JOEL C. ANDERSON

REPRESENTING AVISTA CORPORATION

AVISTA DECOUPLING EVALUATION

(2020 – 2022)

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Final Report

H. Gil Peach & Associates LLC

Vision Statement

To be a world leader in developing truthful measurement and useful results; to support development of efficient, ethical, and effective practices, sustained economically; to advance human development. To improve the quality of life during the era of climate change.

Goals Statement

To build inclusion, diversity, and social justice in support of all technical goals.
Excellence in the integration of knowledge, method, and practice.
Improvement and learning at all levels.
Contextually aware and sound measurement, analysis, and reporting.
Anticipate and meet the needs of our clients.
Awareness of human relevance and of the ethical core of research.
To go further, to find better ways.

Mission Statement

With extensive experience in North America, we can provide the full range of evaluation, verification, policy, management, planning, regulatory and adaptation services – wherever and whenever there is a need.

Environmental Policy Statement

Collectively, we are at a Darwin moment. Either we move to a better model for production; work intensely to mitigate climate change; anticipate and actualize inclusive climate adaptation - or we face being edited out of history.

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AVISTA Decoupling Evaluation 2020-2022

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Introduction & Summary

This evaluation of Avista's Decoupling Mechanism is partly a compliance evaluation and partly a policy evaluation of Avista's decoupling as a specific rate reform (alternative form of rate making) within a specific, three-year, time window: 2020 - 2022.

Each section of the evaluation corresponds to a specific task.

- **Section 1 is a compliance evaluation:** Did Avista comply with the specifics of the decoupling order?

  The overall result in this section of the analysis is that we find the deferrals and rates to have been calculated by the Company in accordance with the Commission guidance as operationalized by the methodological specification in Schedule 75 and Schedule 175.

- **Section 2 is concerned with revenue effects and billing impacts.** Avista's decoupling mechanism has had a stabilizing effect on revenue, reducing variability in half for electric and by one-fifth for natural gas of variability without decoupling.

  On the electric side, between 2018 and 2022 the 3% cap on annual rate increases from the decoupling rate was reached once for residential and twice for non-residential. For natural gas, the rate cap was reached once between 2018 and 2022 in each rate group, residential and non-residential. Deferral balances are driven largely by differences in use per customer from test year assumption. Much of the difference in use per customer is due to weather, especially in electric residential, natural gas residential and natural gas non-residential. Avista's energy efficiency programs have also worked to lower use per customer, especially for the electric non-residential group.

- **Section 3 examines the recovery of fixed cost for both Non-Decoupled and Decoupled customer classes.** Fixed costs can be recovered in the customer charge or in the variable portion of bills, driven by energy use. To what extent are fixed costs recovered in fixed charges for the customer classes that are excluded from the Mechanisms?

  For the electric rate classes not included in decoupling, Avista recovers 16% of fixed charges for Extra Large General Service and 100% of fixed charges for Street and Area Lighting through the customer charge. In comparison, overall (system total), Avista recovers about 14% of total electric fixed cost through fixed customer charges. The percentage runs lower for residential and larger for non-residential.

For natural gas rate classes not included in decoupling, Avista recovers no fixed charge revenue for Interruptible Service and 7% of fixed charges for Transportation Service through the customer charge. In comparison, Avista recovers 32% percent of fixed costs through the customer charge overall (system total), with a slightly higher percentage of recovery in the residential customer class than non-residential customer classes.

- **Section 4 is focused on conservation trends and performance.** In the big picture, overall electrical savings are trending downwards while costs are trending upwards. Overall natural gas savings are trending level while cost is trending upwards. For residential electric low-income households, savings are trending up while cost is trending level. For residential natural gas households, savings are trending up, while cost is trending up. With regard to decoupling, there is no evident impact of decoupling on energy conservation savings. This result is neither unusual nor unexpected. Decoupling is generally not considered to be a driver of energy conservation. Rather, decoupling removes a potential barrier to energy conservation, which is different than driving a direct savings effect.

- **Section 5 is an analysis of new customers.** New customers are meaningfully different from existing customers in both use per customer and decoupled (distribution) revenue generated per customer. Although the effect is stronger for electric service, and not as pronounced for natural gas service, new Residential customers use substantially less energy per customer and generate less revenue per customer than existing residential customers. Because the number of new customers is small relative to existing customers, the overall impact on deferred revenue is limited, but still meaningful.

  For electric service, had new customers been included over the 2020-2022 period, electric Residential customers would have received a smaller refund; electric Non-Residential customers would have received a higher charge through application of the decoupling tariff (RS 75).

  For natural gas service, had new customers been included over the 2020-2022 period, Residential customers would have experienced a higher charge, but Non-Residential customers would have received a lower charge through the decoupling tariff (RS 75).

- **Section 6 is an analysis of alternative calculations of normal weather.** Heating Degree Days (HDDs) are decreasing. As the planet retains more and more heat, instead of reflecting it back into space, the planet, considered as a system, has become unstable in this regard. As the build-up of planetary heat increases, Cooling Degree Days (CDDs) are increasing. This means more and more cooling is needed to counter the increasing heat. The problem of ever-increasing heat is now a physical feature of the planet, and the assumption of a stable weather environment does not work. As directed by the WUTC, Avista has carried out alternative calculations for "normal weather." Each calculation uses an identical mathematical method but employs rolling average data sets of 30-years, 20-years, 15-years, and 10-years. Tabled results of these calculations include HDDs, CDDs, energy usage adjustment, and deferred decoupled revenue adjustment for Residential and Non-Residential customer groups for both electric service and natural gas service. In examination of these calculations, we find that the calculations were correctly performed, and we find cause to rule out using the alternative of 10-years or less. We also found cause to rule out 30-years. This leaves the 20-year and 15-year calculations as the remaining alternatives. The 15-year data window is the shortest period that still produces somewhat stable results of somewhat reasonable accuracy and precision over the observed data and calculations. The 20-year data window is the longest viable period; beyond this, analysis is overly weighted toward older weather that, given the advancing climate trend, is now abnormal.[1] As to precedent, we note that the selection of 20-years coincides with the current practice in climate science calculations (see Appendix).[2] Conversely, the selection of 15-years coincides with NOAA's choice to add a 15-year time series along with its standard 30-year time series for construction of the Typical Meteorological Year (TMY).[3] For decoupling, the 20-year calculation provides a middle ground from a revenue adjustment perspective, producing reasonable but more moderate deferred decoupling revenue adjustments.[4]

[1] To be clear, the mathematics works but the calculated result is abnormal weather rather than normal weather. As discussed in Section 6 and, further, in the Appendix, climate change has weakened the relevance of the concept of normal weather and continues to drain meaning from the concept. A better concept would be "modeled weather," given the effects of climate change (particularly effects of the trend of planetary accumulation of heat energy), for a particular future year. This would require some creative reorientation of the decoupling calculation framework but does not challenge the value of decoupling. The value of decoupling is increase for our climate change era because decoupling becomes an essential climate practice to ensure revenue stability during climate change.

[2] This is for a different calculation (the year we pass the 1.5 degrees Celsius target).

[3] NOAA's series are Typical Meteorological Year (TMY) and Avista's series are observations from the Spokane airport weather station. These are different analytic approaches. NOAA's putting forward the 15-year data along with the 30-year data is not the same as moving to the 15-year data for TMY, but providing an extra series in a combination that would put an average of about 22.5 years but could be weighted more or less towards either series.

[4] We suggest that a quest for "normal weather," though associated with the current decoupling framework, is becoming increasingly less relevant due to changes in the structure of weather driven by climate change. Likely the question of "normal weather" will gradually recede and be replaced by a different question – "what will the weather be in a given future year? For now, however, we are still in the logical/analytic framework of normal weather. So long as we maintain this question, a time window of 20-years is a moderate and reasonable adjustment (away from 30-years), with the caveat that in the future 15-years may be more reasonable, and following that, we will need to change the question to "what will the weather be in a given future year" without reference to normal weather.

Examination of the four alternative operational definitions of normal weather inherently raises the question, “What is normal weather”? This question requires continued follow-on discussion. Prior to approximately 1988, the problem of change in structure of the weather (operationalized as trend change in Heating Degree Days - HDDs) could reasonably be considered to be below need for consideration. It was not considered in analysis and the topic simply did not rise to the level of serious discussion. At that time, the “deferred decoupled revenue – weather component” was not thought to be an indicator of climate change, but to be covering drops in usage due to energy conservation/energy efficiency and all other factors. Since at least 1988, the effect size for climate change has become stronger. Until about 1988 “normal weather” could reasonably be considered a projection of a moving average of past weather. However, for weather adjustment the HDD trend line indicates we need to think though a new definition for “normal weather” that systematically incorporates the trend of ever-increasing planetary heat energy. The climate trend (operationalized as the HDD trend line) means that projected weather is no longer a kind of average result set against a stable background.

Deferred decoupled revenue adjustment continues to remove a barrier to more aggressive energy conservation/energy efficiency and continues (for those fixed costs included in decoupling) to improve revenue stability without changing total collections. However, for weather adjustment, the main driver now is climate change with conservation/energy efficiency secondary. The decoupling weather adjustment should be recognized as primarily a climate change methodological practice to support regular utility revenue in the era of climate change.

- **Section 7 is a CAP analysis**. The use of a decoupling rate cap on customer surcharges has the advantage of smoothing out rates and the disadvantage of prolonging revenue recovery. Raising the rate cap to 5% will sometimes increase bills for the next rate year, while lowering bills for the year after that. Going to no-Cap provides quickest recovery.

- **Section 8 is a check-analysis on theoretically possible adverse effects of decoupling**. We find no conclusive evidence of any current adverse impact of decoupling on cost control, operational efficiency, price signals, or service quality.

- **Section 9 provides a short list of recommendations.**

- **Section 10 presents recommendations, Section 11 is a brief appendix, Section 12 is the bibliography.**

Section 1. Fidelity Analysis

The evaluation objective for the fidelity analysis is to complete a review of whether the deferrals and rates for the time window examined were calculated in accordance with the Commission orders approving the mechanisms. That is, were the mechanisms administered and calculated correctly? This first task is a compliance evaluation. Operationally, we compare the Decoupling Mechanism Development of Deferrals as submitted by Avista in 2021 for the 2020 deferral year[5], as submitted in 2022 for the 2021 deferral year[6], and as submitted in 2023 for the 2022 deferral year to the specification of method in Schedule 75 for electric service and in Schedule 175 for natural gas service[7]. This includes the Earnings Test and the 3% Annual Increase Test.

To support discussion, the relation of decoupling years and decoupling application years in which rates based on data calculations from the decoupling years are applied is shown in Figure 1-1. Five deferral years are shown in the table. This evaluation includes the first three deferral years.

Decoupling - Second Five Years
Docket UG-190335
Order 9 - March 25, 2020

Deferral Year		1	2	3	4	5
		Included in this Report			Future Decoupling Years	
Decoupling Year	Data for calculation of Decoupling Deferral Balance	2020	2021	2022	2023	2024
Rate Year	Year Decoupling Deferral Balance Applied	8/1/2021 to 7/31/2022	8/1/2022 to 7/31/2023	8/1/2023 to 7/31/2024	8/1/2024 to 7/31/2025	8/1/2025 to 7/31/2026

Figure 1-1. Timing of Deferral Balance Accumulation and Decoupling Rate.

[5] Joe Miller, Sr. Manager, Rates and Tariffs to Mr. Mark L. Johnson, Executive Director and Secretary, Washington Utilities and Transportation Commission, May 26, 2021, with attachments; for Tariff WN U-28, Electric Service Electric Decoupling Rate Adjustment; and separate letter for Tariff WN U-29, Natural Gas Service, Natural Gas Decoupling Rate Adjustment.
[6] Joe Miller, Sr. Manager, Rates and Tariffs to Amanda Maxwell, Executive Director and Secretary, Washington Utilities and Transportation Commission, May 27, 2022, with attachments; for Tariff WN U-28, Electric Service, Electric Decoupling rate Adjustment, and separate letter for Tariff WN U-29, Natural Gas Service, Natural Gas Decoupling Rate Adjustment.
[7] Joe Miller, Sr. Manager, Rates and tariffs to Amanda Maxwell, Executive Director and Secretary, Washington Utilities and Transportation Commission, May 31, 2022, with attachments; for Tariff WN U-28, Electric Service, Electric Decoupling rate Adjustment, and separate letter for Tariff WN U-29, Natural Gas Service, Natural Gas Decoupling Rate Adjustment.

Avista's decoupling mechanism allows for the recovery (or return) of the difference between allowed revenue and actual revenue in each decoupling rate year. This difference is referred to as the decoupling deferral balance. It is tracked separately for the decoupled electric residential and non-residential customer groups and for the decoupled residential and non-residential natural gas customer groups.

Decoupling Deferral Balance: The difference between allowed revenue and actual revenue. This value may be positive or negative.

Monthly deferrals are accumulated over a calendar year and used with other determinants to calculate the decoupling rate required to collect or refund the under or over collected revenue. Decoupling rates are calculated according to Schedule 75 (electric) and Schedule 175 (natural gas) and become effective on August 1 of the year following the year for which deferral balances are calculated.[8]

The first deferral year examined in this report resulted in a deferral balance at the end of calendar year 2020 that was used, along with other determinants, to calculate the first decoupling rate in effect during the first "decoupling rate year" for this cycle is August 1, 2021, through July 31, 2022). The same process is followed for the second deferral year and for the third deferral year.

There is a 3% limit capping the part of the Decoupling Deferral Balance that may be applied in the following Decoupling Rate Year. Any overage is carried into the next Decoupling Rate Year. For example, any overage in a calculation for the first Decoupling Rate Year would be carried over to be added into the amount calculated for the second Deferral Year.

Each year, electric and natural gas results are separately developed. Also, within each year and energy source, Residential and Non-Residential Rate Groups are separately analyzed.

[8] The details of Avista's decoupling mechanism are included in the Final Order ("Order 5") for Docket Numbers UE-140188 and UG-140189 (*consolidated*), November 25, 2014. Certain changes, including the exclusion from decoupling of new meters until the next rate case and an alignment of dates, are specified in the Final Order (Order 09) in Dockets UG-190334, UG-190335, UE-190222 (*consolidated*), March 25, 2020. Changes affecting calculations are: (1) The effective date of annual rate adjustment filing is moved from November 1 to August 1. (2) Customers connected to Avista's system after the ratemaking test year will be excluded from the decoupled deferred revenue calculations. Furthermore, the Company will include a status update in its yearly decoupling report identifying the number of new customers excluded from the mechanism and associated costs and revenues. (3) The Company will add an annual revenue-per-customer true-up to the December deferred revenue calculation.

We first examine the working of the electric decoupling mechanism and of the natural gas decoupling mechanisms in detail for the 2020 deferral year. Then, the same detailed review is repeated for the 2021 and 2022 deferral years.

2020 Decoupling Mechanism – Electric (Schedule 75) and Gas (Schedule 175)

The decoupling mechanism is designed to capture all fixed costs that are to be collected from the volumetric portion of rates.[9] With decoupling, the total amount remaining for recovery is allocated to customer bills according to a model for recovery in a structured manner on an ongoing basis.

As specified, for (Electric) Schedule 75 and (Natural Gas) Schedule 175, calculations were carried out separately and in parallel, for Residential and Non-Residential accounts. For each of these groups of accounts, the sum of monthly deferral amounts over 2020 is the cumulative deferral (rebate or surcharge) for 2020. This cumulative deferral for 2020 is then applied over the twelve months beginning August 1, 2021. Amortization of the cumulative deferral balance developed over calendar 2020 was implemented over the twelve-month time window from August 1, 2021, to October 31, 2022.

Electric Schedule 75

- For (Electric) Schedule 75, Group 1 is Residential customers (Schedules 1 and 2).
- For (Electric) Schedule 75, Group 2 is Non-Residential customers (Schedules 11, 12, 21, 22, 23, 30, 31 and 32).
- For (Electric) Schedule 75, two customer classes were not decoupled (Schedule 25 – Extra Large General Service and Schedules 41-48 – Street and Area Lighting). The non-decoupled customer classes are not included in this analysis.

Natural Gas Schedule 175

- For (Natural Gas) Schedule 175, Group 1 is Residential customers (Schedules 101 and 102).

[9] Cost-of-service studies follow the principles of cost causation, equal rates of return across rate classes, and gradualism (Lowell E. Alt Jr., *Electrical Utility Rate Setting*, A Practical Guide to the Retail Rate-Setting Process for Regulated Electric and Natural Gas Utilities, 2006). Fair rates, according to the principle of cost causation, are rates that apply variable costs (costs that vary with the number of energy units used) to the variable portion of the customer energy bills (the energy charge) and fixed costs (costs that are caused by being on the system, that do not vary with the number of energy units used) to the fixed portion of the customer bill (the customer charge). However, commissions, in order to implement federal, state, or provincial policy, are granted the flexibility to assign costs differently. In decoupling, fixed charges that have been previously included in the energy charge are recaptured from the energy charge and an effect of decoupling is to treat these amounts as fixed charges.

- For (Natural Gas) Schedule 175, Group 2 is Non-Residential customers (Schedules 111, 112, 121, 122, and 131.
- For (Natural Gas) Schedule 175, three rate schedules were excluded from the decoupling mechanism (Schedules 132, 146, and 148). Non-decoupled customers are not included in this analysis.

Electric Group 1 (Residential) and Group 2 (Non-Residential)

Schedule 75A is used to develop the *Decoupled Revenue per Customer*. Schedule 75B uses the results from Schedule 75A to develop the *Monthly Decoupling Deferral*. There are seven calculation steps in Schedule 75A. There are eight calculation steps in Schedule 75B. These are developed in this subsection of the report. Results for Schedule 75A for both Electric Residential and Electric Non-Residential customers are shown in Tables 1-1 through 1-3. Results for Schedule 75B are shown separately for Electric Residential customers in Tables 1-4 and 1-6, and for Electric Non-Residential customers in Table 1-5 and 1-7. A required true-up for number of customers is shown in Table 1-8.[10]

Schedule 75A – Decoupled Revenue per Customer

Calculation of Decoupled Revenue per Customer for Electric Residential and Electric Non-Residential is specified in seven steps in Schedule 75A.[11] These steps are implemented in Tables 1-1, 1-2 and 1-3.

Step 1: Determine the Total Normalized Revenue.

Total Normalized Revenue is equal to the final approved base rate revenue approved in the Company's last general rate case, individually for each Rate Schedule. Table 1-1, Line 1 shows initial Total Normalized Net Revenue. In Line 2 the Allowed Revenue Increase is shown. The sum of Line 1 and Line 2 is the Allowed Base Rate Revenue or Total Normalized Revenue. Note that values in the Total column for Lines 1-6 are not used since they include results for non-decoupled schedules.

[10] Tables in this section of the report are from annual decoupling rate filing in May of each year.
[11] Schedule 75, Decoupling Mechanism – Electric, WN U-28, Substitute Seventh Revision Sheet 75 canceling Sixth Revision Sheet 75, AVISTA CORPORATION dba Avista Utilities, Issued July 1, 2022, Effective October 1, 2022. See attached "DESCRIPTION OF THE ELECTRIC DECOUPLING MECHANISM: Calculation of Monthly Allowed Delivery Revenue Per Customer, Original Sheet 75A, Issued June 12, 2015, Effective August 1, 2015.

Table 1-1: 2020 Development of Electric Decoupled Revenue per Customer.

Electric Decoupling Mechanism
Development of Decoupled Revenue by Rate Schedule - Electric
Washington Docket No. UE-170485 Compliance Filing

		TOTAL	RESIDENTIAL SCHEDULE 1,2	GENERAL SVC. SCH. 11,12	LG. GEN. SVC. SCH. 21,22	PUMPING SCH. 30, 31, 32	EX LG GEN SVC SCHEDULE 25	ST & AREA LTG SCH. 41-48
1	Total Normalized 12ME Dec 2016 Revenue	$ 492,134,000	$ 209,489,000	$ 73,766,000	$ 126,766,000	$ 10,894,000	$ 64,348,000	$ 6,871,000
2	Allowed Revenue Increase (Attachment 1)	$ 10,763,000	$ 4,904,000	$ 1,291,000	$ 2,775,000	$ 238,000	$ 1,405,000	$ 150,000
3	Allowed Base Rate Revenue	$ 502,897,000	$ 214,393,000	$ 75,057,000	$ 129,541,000	$ 11,132,000	$ 65,753,000	$ 7,021,000
4	Normalized kWhs (12ME Dec 2016 Test Year)	5,658,613,712	2,361,885,989	623,243,883	1,409,459,201	133,495,310	1,107,408,158	23,121,171
5	Retail Revenue Adjustment (line 14)	$ 0.01900	$ 0.01900	$ 0.01900	$ 0.01900	$ 0.01900	$ 0.01900	$ 0.01900
6	Variable Power Supply Revenue (L4 * L5)	$ 107,513,661	$ 44,875,834	$ 11,841,634	$ 26,779,725	$ 2,536,411	$ 21,040,755	$ 439,302
7	Delivery & Power Plant Revenue (L3 - L6)	$ 344,089,397	$ 169,517,166	$ 63,215,366	$ 102,761,275	$ 8,595,589		
8	Customer Bills (12ME Dec 2016 Test Year)	2,945,836	2,518,371	375,436	22,836	29,193		
9	Allowed Basic Charges		$ 9.00	$ 20.00	$ 500.00	$ 20.00		
10	Basic Charge Revenue (Ln 8 * Ln 9)	$ 42,175,919	$ 22,665,339	$ 7,508,720	$ 11,418,000	$ 583,860		
11	Decoupled Revenue	$ 301,913,478	$ 146,851,827	$ 55,706,646	$ 91,343,275	$ 8,011,729	Excluded From Decoupling	

Step 2: Determine the Variable Power Supply Revenue.

This value is shown on Line 6 and is the product of Normalized kWh on Line 4 and Retail Revenue Credit from Line 5. Values in the Total column for Lines 1-6 are not used since they include results for non-decoupled schedules.

Step 3: Determine Delivery and Power Plant Revenue.

For the decoupled schedules *only*, subtract Variable Power Supply Revenue (Line 6) from the Total Normalized Revenue (Line 3) and enter results on Line 7. Beginning with Line 7, values in the Total column are valid for decoupling.

Step 4: Remove Basic Charge Revenue.

Because the decoupling mechanism only tracks revenue that varies with customer energy usage, revenue directly recovered from Fixed Charges is removed in this step. Basic Charge Revenue is shown on Line 10. It is the product of the number of Customer Bills (2016 Test Year) on Line 8 times the Allowed Basic Charge (Line 9).[12]

Step 5: Determine Decoupled Revenue.

Decoupled Revenue is equal to the Delivery and Power Plant Revenue (Step 3; Line 7) minus the Basic Charge Revenue (Step 4; Line 10). Decoupled Revenue is shown on Line 11.

[12] Basic charge includes minimum charge revenue for non-residential customers.

Step 6: Determine Decoupled Revenue per Customer.

In this step, Decoupled Revenue from Line 11 is put on a per customer basis. The Decoupled Revenue is divided by the approved Rate Year number of customers (by Rate Group). This determines the annual Allowed Decoupled Revenue per Customer.

Table 1-2: 2020 Electric Decoupled Revenue per Customer.

Avista Utilities
Electric Decoupling Mechanism
Development of Annual Decoupled Revenue Per Customer - Electric
Washington Docket No. UE-170485 Compliance Filing

Line No.		Source		Residential		Non-Residential Schedules*
	(a)	(b)		(c)		(d)
1	Decoupled Revenues	Attachment 4, Page 1	$	146,851,827	$	155,061,651
2	Test Year # of Customers 12 ME 12.2016	Revenue Data		209,864		35,622
3	Decoupled Revenue per Customer	(1) / (2)	$	699.75	$	4,352.97
	* Schedules 11, 12, 21, 22, 31, 32.					
	Attachment 4, Page 2					
	Revenues					
	From revenue per customer		$	146,852,334	$	155,061,497
	From basic charge		$	22,665,339	$	19,510,580
	From power supply		$	44,875,834	$	41,157,769
	Total		$	214,393,507	$	215,729,847

Step 7: Determine the Monthly Decoupled Revenue per Customer.

Step 7 converts Allowed Decoupled Revenue per Customer (by Rate Group) into monthly values. The assignment of monthly values is carried out by modeling monthly kWh use (by Rate Group) in relationship to the annual kWh (Table 1-3). Kilowatt hours (kWh) for Group 1 (Residential) for 2020 are shown in Line 3 and for Group 2 (Non-Residential) in Line 6. Below the monthly values (Lines 4 and 7) monthly percentages are shown. Lines 11 and 14 show the use of these percentages, applied to annual Allowed Decoupled Revenue per Customer (by Rate Group) to generate monthly values. Table 1-3 shows the monthly results for both Electric Residential and Electric Non-Residential decoupling.

Table 1-3: 2020 Development of Monthly Electric Decoupled Revenue per Customer.

Avista Utilities
Electric Decoupling Mechanism
Development of Monthly Decoupled Revenue Per Customer - Electric
Washington Docket No. UE-170485 Compliance Filing

Line No.		Source	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	TOTAL
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
1	**Electric Sales**														
2	*Residential*														
3	- Weather-Normalized kWh Sales	Monthly Test Year	282,718,944	229,028,914	209,765,396	176,926,076	154,900,987	143,616,706	190,502,271	171,958,392	162,813,881	159,069,574	215,944,062	264,640,786	2,361,885,989
4	- % of Annual Total	% of Total	11.97%	9.70%	8.88%	7.49%	6.56%	6.08%	8.07%	7.28%	6.89%	6.73%	9.14%	11.20%	100.00%
5	*Non-Residential**														
6	- Weather-Normalized kWh Sales	Monthly Test Year	179,053,129	167,633,774	172,512,516	163,846,532	181,092,306	185,499,649	204,307,747	192,388,070	180,766,696	182,872,741	162,705,681	193,519,554	2,166,198,394
7	- % of Annual Total	% of Total	8.27%	7.74%	7.96%	7.56%	8.36%	8.56%	9.43%	8.88%	8.34%	8.44%	7.51%	8.93%	100.00%
8	**Monthly Decoupled Revenue Per Customer ("RPC")**														
9	*Residential*														
10	-UE-170485 Decoupled RPC	Attachment 4, P. 2 L. 3													$ 699.75
11	- Monthly Decoupled RPC	(4) x (10)	$ 83.76	$ 67.85	$ 62.15	$ 52.42	$ 45.89	$ 42.55	$ 56.44	$ 50.95	$ 48.24	$ 47.13	$ 63.98	$ 78.40	$ 699.75
12	*Non-Residential**														
13	-UE-170485 Decoupled RPC	Attachment 4, P. 2 L. 3													$ 4,352.97
14	- Monthly Decoupled RPC	(7) x (13)	$ 359.81	$ 336.86	$ 346.66	$ 329.25	$ 363.90	$ 372.76	$ 410.56	$ 386.60	$ 363.25	$ 367.48	$ 326.96	$ 388.88	$ 4,352.97

* Schedules 11, 12, 21, 22, 31, 32.

Schedule 75B – Electric Monthly Decoupling Deferral

Monthly values developed in accordance with Schedule 75A are then used in the implementation of Schedule 75B.

Schedule 75B specifies the method for developing the *Monthly Decoupling Deferral* for electric service. The reporting format for calculation of the monthly electric decoupling deferral for 2020 is shown in Table 1-4 for Electric Residential and in Table 1-5 for Electric Non-Residential.[13] These one-month tables are included to introduce the format and calculation steps used in the actual tables (Tables 1-6 for Electric Residential & 1-7 for Electric Non-Residential). In Table 1-6 and Table 1-7, the monthly decoupling deferral amounts across 2020 sum to the annual total decoupling deferral for 2020. For the electric residential group (Table 1-6), deferred revenue for 2020 is a refund to customers of $810,734.[14] In Table 1-7, deferred revenue for 2020 for the electric non-residential group is a decoupling surcharge to customers of $10,452,475.[15]

The Schedule 75B calculation steps for Electric Residential follow. There are eight steps. The sequence of the line numbers in Table 1-4 are keyed to the eight steps. Steps 1 through 5 are required to remove new customers (new hookups) from the calculation. These steps apply to the short table (Table 1-4) and the full table (Table 1-5). The short table is included to introduce the format used in the full table.

[13] Only one month (April 2020) is shown here to keep the table readable on the page. Full tables are provided as Table 1-6 (Electric Residential) and 1-7 (Electric Non-Residential).
[14] Table 1-5, Line 24, Balance.
[15] Table 1-6, line 26, (Rebate/Surcharge) Balance.

Electric – Residential (Schedule 75B)

Step 1: Deduct new hookup customers. New hookup customers (Line 5) are deducted from total actual number of customers (Line 1) to determine the actual number of test year existing customers each month. The result (actual number of decoupled customers after subtracting out new customers) is shown on Line 9.

Step 2: Calculate total Allowed Decoupled Revenue each month. This is calculated by multiplying the number of Actual Customers after removing new customers (Line 9) by the Monthly Decoupled Revenue per Customer (Line 10). The result is shown on Line 11, Decoupled Revenue.

Step 3: Deduct actual new hookup customer revenue from total actual revenue. This determines the actual test year existing customer revenue collected in the applicable month. To form this result, Actual Base Rate Revenue (Line 3) is adjusted by subtracting New Customer Base Rate Revenue (Line 7). The result is shown on Line 12.

Step 4: Deduct actual new hookup customer fixed charge revenue from total actual fixed charge revenue. Line 8, New Customer Basic Charge Revenue, is subtracted from Line 4, Actual Basic Charge Revenue. The result, Actual Basic Charge Revenue (Test Year Existing), is shown on Line 13.

Step 5: Deduct actual new hookup customer kWh sales from total actual kWh sales. This is Line 2 (Actual Usage kWh) minus Line 6 (New Customer Usage (kWh). The result is the Actual Usage (kWh)/Test Year Existing (Line 14) from which new customer (new hookups) actual usage has been removed. Then, Actual Usage (kWh)/Test Year Existing in Line 14 is multiplied by the approved Retail Revenue Credit (Line 15). The result is the revenue collected related to the variable power supply (Variable Power Supply Payments; Line 16). When Step 5 is completed, all quantities remaining in the analysis have been adjusted to remove new customers (new hookups).

Step 6: Compute Customer Decoupled Payments. Actual Decoupled Revenue is calculated by subtracting the Actual Basic Charge Revenue/Test Year Existing in Line 13 and the Variable Power Supply Payments (Line 16) from the Actual Base Rate Revenue/Test Year Existing (Line 12). Customer Decoupled Payments is shown on Line 17.

Table 1-4: 2020 Electric Residential Deferral – Format.

Decoupling Mechanism - UE-170485 Base effective 5/1/2018,
Electric Residential
Development of WA Electric Deferrals (Calendar Year 2020)

Line No.		Source		Month Apr-20
	(a)	(b)		(f)
1	Actual Customers	Revenue System		220,604
2	Actual Usage (kWhs)	Revenue System		188,286,073
3	Actual Base Rate Revenue	Revenue System	$	17,970,007
4	Actual Basic Charge Revenue	Revenue System	$	2,021,544
5	New Customers	Revenue System		3,261
6	New Customer Usage (kWhs)	Revenue System		1,762,897
7	New Customer Base Rate Revenue	Revenue System	$	175,571
8	New Customer Basic Charge Revenue	Revenue System	$	29,574
9	Actual Customers/Test Year Existing	(1) - (5)		217,343
10	Monthly Decoupled Revenue per Customer	Attachment 3, Page 3		$55.20
11	Decoupled Revenue	(9) x (10)	$	11,998,161
12	Actual Base Rate Revenue/Test Year Existing	(3) - (7)	$	17,794,436
13	Actual Basic Charge Revenue/Test Year Existing	(4) - (8)	$	1,991,970
14	Actual Usage (kWhs)/Test Year Existing	(2) - (6)		186,523,176
15	Retail Revenue Credit ($/kWh)	Attachment 3, Page 1	$	0.01895
16	Variable Power Supply Payments	(14) x (15)	$	3,534,614
17	Customer Decoupled Payments	(12) - (13) -(16)	$	12,267,852
18	Residential Revenue Per Customer Received	(17) / (9)		$56.44
19	Deferral - Surcharge (Rebate)	(6) - (17)	$	(269,691)
20	Deferral - Revenue Related Expenses	Rev Conv Factor	$	11,966
21		FERC Rate		4.75%
22	Interest on Deferral	Avg Balance Calc	$	8,255
23	**Monthly Residential Deferral Totals**		**$**	**(249,470)**
24	Cumulative Deferral (Rebate)/Surcharge Balance	Σ((19) ,(20) , (22))	$	1,957,141

As approved in Docket No. UE-190334, the Company is required to calculate decoupled revenue using YTD average customers, compare to what was recorded using monthly customer counts, and record the difference in December so that the annual decoupled revenue is based on YTD average customers. This amount includes that annual true-up that resulted in a decrease to decoupled revenue of $10,366.26.

Step 7: Compute Balance to be Deferred by the Company as a Surcharge or as a Rebate. The result (Deferral – Surcharge/Rebate) is shown on Line 19. It is computed in Table 1-4 by subtracting Customer Decoupled Payments of $12,267,852 (Line 17) from Decoupled Revenue of $11,998,161 (Line 11).[16]

[16] Notation of source for Line 19, Deferral – Surcharge (Rebate) is shown as “(6) – (17)”. This should be “(11-17)”; the calculation, however, is correct.

This amount is then adjusted for Revenue Related Expenses (Line 20) and for interest at the FERC rate (FERC interest rate at Line 21 and interest at Line 22). The result is the Monthly Electric Residential Deferral Total (Line 23).

These monthly amounts are then cumulated in Line 24. The Total Cumulative Deferral (Rebate)/Surcharge Balance is tracked in Line 48. The total cumulative deferral for Electric Residential is a rebate to customers of $810,734.[17]

Step 8: Comparison. At the end of every 12-month deferral period, the annual decoupled revenue per customer, by rate group, is multiplied by the average annual number of actual test year existing customers. The result of that calculation is compared to the actual deferred revenue for the same 12-month period. The difference between the actual deferred revenue, and the calculated value, is then added to, or subtracted from, the total deferred balance by Rate Group. This calculation is shown in Table 1-8.

Electric – Non-Residential (Schedule 75B)

The Schedule 75B calculation for Electric Non-Residential steps follow. There are eight steps. The sequence of the line numbers are keyed to the eight steps. Steps 1 through 5 are required to remove new customers (new hookups) from the calculation.

Step1: Deduct new hookup customers. New hookup customers (Line 29) are deducted from the total actual number of customers (Line 25) to determine the actual number of test year existing customers each month. The result (actual number of customers after subtracting out new customers) is in Line 33.

Step 2: Calculate total Allowed Decoupled Revenue each month. This is calculated by multiplying the number of Actual Customers after removing new customers (Line 33) by the Monthly Decoupled Revenue per Customer (Line 34). The result is shown on Line 35.

Step 3: Deduct actual new hookup customer revenue from total actual revenue. This determines the actual test year existing customer revenue collected in the applicable month. To form this result, Actual Base Rate Revenue (Line 27) is adjusted by subtracting New Customer Base Rate Revenue (Line 31). The result is shown on Line 36.

[17] Table 1-6, line 24, (Rebate/Surcharge) Balance, last column.

Step 4: Deduct actual new hookup customer fixed charge revenue from total actual fixed charge revenue. Line 32, New Customer Basic Charge Revenue, is subtracted from Line 28, Actual Basic Charge Revenue. The result, Actual Basic Charge Revenue (Test Year Existing), is shown on Line 37.

Step 5: Deduct actual new hookup customer kWh sales from total actual kWh sales. This is Line 26 (Total Actual kWh Sales) minus Line 30 (New Customer Usage (kWh). The result is the Actual Usage (kWh) from which new customer actual usage has been removed. The result is shown in Line 38. Then, Actual Usage (kWh) in Line 38 is multiplied by the approved Retail Revenue Credit (Line 39). The result is the revenue collected related to the variable power supply (Variable Power Supply Payments in Line 40). When Step 5 is completed, all remaining quantities have been adjusted to remove new customers (new hookups).

Step 6: Compute Customer Decoupled Payments. Actual Decoupled Revenue is calculated by subtracting the Actual Basic Charge Revenue (Test Year Existing) in Line 37 and the Variable Power Supply Payments (Line 40) from the Actual Base Rate Revenue (Line 36) and is shown on Line 41.

Step 7: Compute Balance to be Deferred by the Company as a Surcharge or as a Rebate. The Balance (for each month) is computed by subtracting Customer Decoupled Payments (Line 41) from Decoupled Revenue (Line 35).[18] The result (Deferral – Surcharge/Rebate) is shown on Line 43. This amount is then adjusted for Revenue Related Expenses (Line 44) and for interest at the FERC rate (Lines 44 and 45). The result is the Monthly Non-Residential Deferral Total (Line 47). These monthly amounts are cumulated in Line 48

Monthly Residential Deferral Total for each month is shown just below Line 12. This is the difference between the Actual Decoupled Revenue (Step 6; Line 9) and the Allowed Decoupled Revenue (Step 2; Line 3) plus any interest on the deferral.

The Total Cumulative Deferral (Rebate)/Surcharge Balance is tracked in Line 48. The total cumulative deferral for Electric Non-Residential is a surcharge to customers of $10,452,475.[19]

[18] In Table 1-5, the source for Line 43 is listed as (31) – (41). This should read (35) – (41). Although there is an error in notation, the calculation is correct. Both notation and calculation are correct in Table 1-6, Line 43.
[19] Table 1-6, line 26, (Rebate/Surcharge) Balance.

Table 1-5: 2020 Electric Non-Residential Deferral - Format.

Decoupling Mechanism - UE-170485 Base effective 5/1/2018,
Electric Non-Residential
Development of WA Electric Deferrals (Calendar Year 2020)

Line No.		Source	Month Apr-20
	(a)	(b)	(f)
	Non-Residential Group		
25	Actual Customers	Revenue System	37,426
26	Actual Usage (kWhs)	Revenue System	139,907,714
27	Actual Base Rate Revenue	Revenue System	$ 15,261,341
28	Actual Basic Charge Revenue	Revenue System	$ 1,726,758
29	New Customers	Revenue System	873
30	New Customer Usage (kWhs)	Revenue System	2,007,628
31	New Customer Base Rate Revenue	Revenue System	$ 238,432
32	New Customer Basic Charge Revenue	Revenue System	$ 33,333
33	Actual Customers/Test Year Existing	(25) - (29)	36,553
34	Monthly Decoupled Revenue per Customer	Attachment 3, Page 3	$335.56
35	Decoupled Revenue	(33) x (34)	$ 12,265,725
36	Actual Base Rate Revenue/Test Year Existing	(27) - (31)	$ 15,022,910
37	Actual Basic Charge Revenue/Test Year Existing	(28) - (32)	$ 1,693,425
38	Actual Usage (kWhs)/Test Year Existing	(26) - (30)	137,900,086
39	Retail Revenue Credit ($/kWh)	Attachment 3, Page 1	$ 0.01895
40	Variable Power Supply Payments	(38) x (39)	$ 2,613,207
41	Customer Decoupled Payments	(36) - (37) -(40)	$ 10,716,278
42	Non-Residential Revenue Per Customer Received	(41) / (33)	$293.17
43	Deferral - Surcharge (Rebate)	(31) - (41)	$ 1,549,340
44	Deferral - Revenue Related Expenses	Rev Conv Factor	$ (68,743)
45		FERC Rate	4.75%
46	Interest on Deferral	Avg Balance Calc	$ 8,689
47	**Monthly Non-Residential Deferral Totals**		**$ 1,489,286**
48	Cumulative Deferral (Rebate)/Surcharge Balance	Σ((43) ,(44) , (46))	$ 2,944,082
49	**Total Cumulative Deferral (Rebate)/Surcharge Balance**		$ 4,901,223

As approved in Docket No. UE-190334, the Company is required to calculate decoupled revenue using YTD average customers, compare to what was recorded using monthly customer counts, and record the difference in December so that the annual decoupled revenue is based on YTD average customers. This amount includes that annual true-up that resulted in an increase to decoupled revenue of $262.05.

Step 8: Comparison. At the end of every 12-month deferral period, the annual decoupled revenue per customer, by rate group, will be multiplied by the average annual number of actual test year existing customers. The results of that calculation will be compared to the actual deferred revenue for the same 12-month period. The difference between the actual deferred revenue and the calculated value will be added to, or subtracted from, the total deferred balance by Rate Group. This calculation is shown in Table 1-8, and results in a decrease of $10,366.26 for Residential; and an increase of $262.05 for Non-Residential.[20]

[20] Table 1-8, Net increase/(decrease) to Decoupled Revenue due to Average Calculation (middle of Table for Residential, bottom line for Non-Residential).

Table 1-6: 2020 Electric Decoupling - Residential.

Decoupling Mechanism - UE-170485 Base effective 5/1/2018,
UE-190334 Base effective 4/1/2020
Development of WA Electric Deferrals (Calendar Year 2020)

Line No.		Source	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Total
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
	Residential Group														
1	Actual Customers	Revenue System				220,604	220,212	220,636	220,799	220,884	221,811	221,953	222,003	222,995	
2	Actual Usage (kWhs)	Revenue System				188,286,073	159,744,333	155,578,204	190,128,187	205,649,832	168,829,432	173,706,610	230,501,382	274,711,064	
3	Actual Base Rate Revenue	Revenue System				$ 17,970,007	$ 15,313,338	$ 15,206,666	$ 18,292,550	$ 20,121,070	$ 16,336,511	$ 16,643,397	$ 22,255,095	$ 26,944,369	
4	Actual Basic Charge Revenue	Revenue System				$ 2,021,544	$ 2,023,335	$ 2,043,423	$ 2,040,597	$ 2,045,007	$ 2,041,983	$ 2,038,977	$ 2,036,844	$ 2,040,939	
5	New Customers	Revenue System				3,261	3,380	3,544	3,916	4,199	4,652	4,942	5,251	5,437	
6	New Customer Usage (kWhs)	Revenue System				1,762,897	1,373,083	1,398,479	1,613,174	2,155,535	2,320,559	2,018,639	3,258,845	4,691,916	
7	New Customer Base Rate Revenue	Revenue System				$ 175,571	$ 144,960	$ 149,069	$ 169,826	$ 219,597	$ 235,292	$ 211,411	$ 326,948	$ 464,626	
8	New Customer Basic Charge Revenue	Revenue System				$ 29,574	$ 30,636	$ 32,742	$ 35,559	$ 37,701	$ 40,851	$ 44,244	$ 47,340	$ 48,843	
9	Actual Customers/Test Year Existing	(1) - (5)	221,120	220,271	220,636	217,343	216,832	217,092	216,883	216,685	217,159	217,011	216,752	217,558	2,615,342
10	Monthly Decoupled Revenue per Customer	Attachment 3, Page 3	$83.76	$67.85	$62.15	$55.20	$50.42	$48.03	$52.84	$61.70	$46.23	$51.24	$68.57	$86.79	$735.32
11	Decoupled Revenue	(9) x (10)	$ 18,521,106	$ 14,946,228	$ 13,711,791	$ 11,998,161	$ 10,933,097	$ 10,426,781	$ 11,459,637	$ 13,370,263	$ 10,040,141	$ 11,119,340	$ 14,861,953	$ 18,871,080 *	$ 160,259,577
12	Actual Base Rate Revenue/Test Year Existing	(3) - (7)	$ 23,579,888	$ 20,630,118	$ 20,089,065	$ 17,794,436	$ 15,168,378	$ 15,057,597	$ 18,122,724	$ 19,901,473	$ 16,101,219	$ 16,431,986	$ 21,928,147	$ 26,479,743	$ 231,284,774
13	Actual Basic Charge Revenue/Test Year Existing	(4) - (8)	$ 2,025,764	$ 2,014,030	$ 2,024,532	$ 1,991,970	$ 1,992,699	$ 2,010,681	$ 2,005,038	$ 2,007,306	$ 2,001,132	$ 1,994,733	$ 1,989,504	$ 1,992,096	$ 24,049,485
14	Actual Usage (kWhs)/Test Year Existing	(2) - (6)	258,096,251	225,826,180	218,575,770	186,523,176	158,371,250	154,179,725	188,515,013	203,494,297	166,508,873	171,687,971	227,242,537	270,019,148	2,429,040,190
15	Retail Revenue Credit ($/kWh)	Attachment 3, Page 1	$ 0.01900	$ 0.01900	$ 0.01900	$ 0.01895	$ 0.01895	$ 0.01895	$ 0.01895	$ 0.01895	$ 0.01895	$ 0.01895	$ 0.01895	$ 0.01895	
16	Variable Power Supply Payments	(14) x (15)	$ 4,903,829	$ 4,290,697	$ 4,152,940	$ 3,534,614	$ 3,001,135	$ 2,921,706	$ 3,572,359	$ 3,856,217	$ 3,155,343	$ 3,253,487	$ 4,306,246	$ 5,116,863	$ 46,065,437
17	Customer Decoupled Payments	(12) - (13) -(16)	$ 16,650,296	$ 14,325,391	$ 13,911,593	$ 12,267,852	$ 10,174,544	$ 10,125,210	$ 12,545,326	$ 14,037,950	$ 10,944,744	$ 11,183,766	$ 15,632,397	$ 19,370,784	$ 161,169,853
18	Residential Revenue Per Customer Received	(17) / (9)	$75.30	$65.04	$63.05	$56.44	$46.92	$46.64	$57.84	$64.79	$50.40	$51.54	$72.12	$89.04	$739.50
19	Deferral - Surcharge (Rebate)	(11) - (17)	$ 1,870,810	$ 620,838	$ (199,802)	$ (269,691)	$ 758,552	$ 301,570	$ (1,085,690)	$ (667,687)	$ (904,603)	$ (64,427)	$ (770,444)	$ (499,704)	$ (910,276)
20	Deferral - Revenue Related Expenses	Rev Conv Factor	$ (87,324)	$ (28,979)	$ 9,326	$ 11,966	$ (33,656)	$ (13,380)	$ 48,171	$ 29,625	$ 40,136	$ 2,859	$ 34,184	$ 22,171	$ 35,098
21		FERC Rate	4.96%	4.96%	4.96%	4.75%	4.75%	4.75%	3.43%	3.43%	3.43%	3.25%	3.25%	3.25%	
22	Interest on Deferral	Avg Balance Calc	$ 3,686	$ 8,610	$ 9,475	$ 8,225	$ 9,182	$ 11,223	$ 7,065	$ 4,691	$ 2,557	$ 1,176	$ 99	$ (1,545)	$ 64,443
23	**Monthly Residential Deferral Totals**		**$ 1,787,172**	**$ 600,469**	**$ (181,000)**	**$ (249,500)**	**$ 734,078**	**$ 299,413**	**$ (1,030,453)**	**$ (633,371)**	**$ (861,909)**	**$ (60,392)**	**$ (736,162)**	**$ (479,078)**	**$ (810,734)**
24	Cumulative Deferral (Rebate)/Surcharge Balance	Σ((19) ,(20) , (22))	$ 1,787,172	$ 2,387,641	$ 2,206,641	$ 1,957,141	$ 2,691,218	$ 2,990,632	$ 1,960,178	$ 1,326,807	$ 464,897	$ 404,505	$ (331,657)	**$ (810,734)**	

*** - As approved in Docket No. UE-190334, the Company is required to calculate decoupled revenue using YTD average customers, compare to what was recorded using monthly customer counts, and record the difference in December so that the annual decoupled revenue is based on YTD average customers. This amount includes that annual true-up that resulted in a decrease to decoupled revenue of $10,366.26.**

Table 1-7: 2020 Electric Decoupling - Non-Residential.

Decoupling Mechanism - UE-170485 Base effective 5/1/2018,
UE-190334 Base effective 4/1/2020
Development of WA Electric Deferrals (Calendar Year 2020)

Line No.		Source	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Total
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
	Non-Residential Group														
25	Actual Customers	Revenue System				37,426	37,036	37,925	37,616	37,401	37,679	37,795	37,724	37,949	
26	Actual Usage (kWhs)	Revenue System				139,907,714	148,830,839	164,045,166	185,995,405	181,437,975	172,570,197	186,445,471	152,188,443	168,250,485	
27	Actual Base Rate Revenue	Revenue System				$ 15,261,341	$ 15,696,874	$ 17,336,325	$ 19,145,563	$ 18,905,149	$ 18,121,063	$ 19,453,895	$ 16,587,759	$ 17,769,454	
28	Actual Basic Charge Revenue	Revenue System				$ 1,726,758	$ 1,720,550	$ 1,787,846	$ 1,757,369	$ 1,744,423	$ 1,745,238	$ 1,764,533	$ 1,718,318	$ 1,754,820	
29	New Customers	Revenue System				873	919	1,048	1,135	1,177	1,273	1,363	1,486	1,529	
30	New Customer Usage (kWhs)	Revenue System				2,007,628	1,811,961	2,179,064	2,350,154	3,078,900	4,524,953	4,003,265	4,655,162	5,333,626	
31	New Customer Base Rate Revenue	Revenue System				$ 238,432	$ 230,638	$ 280,786	$ 299,927	$ 367,867	$ 504,817	$ 507,503	$ 551,396	$ 612,911	
32	New Customer Basic Charge Revenue	Revenue System				$ 33,333	$ 34,931	$ 41,255	$ 39,311	$ 38,306	$ 42,245	$ 43,531	$ 47,938	$ 52,393	
33	Actual Customers/Test Year Existing	(25) - (29)	37,482	37,041	37,523	36,553	36,117	36,877	36,481	36,224	36,406	36,432	36,238	36,420	439,794
34	Monthly Decoupled Revenue per Customer	Attachment 3, Page 3	$359.81	$336.86	$346.66	$335.56	$361.67	$376.01	$413.67	$396.88	$352.61	$379.63	$363.03	$358.52	$4,380.91
35	Decoupled Revenue	(33) x (34)	$ 13,486,278	$ 12,477,618	$ 13,007,853	$ 12,265,618	$ 13,062,557	$ 13,866,018	$ 15,091,182	$ 14,376,466	$ 12,837,137	$ 13,830,788	$ 13,155,503	$ 13,057,563 **	$ 160,514,581
36	Actual Base Rate Revenue/Test Year Existing	(27) - (31)	$ 18,011,842	$ 17,151,617	$ 17,206,840	$ 15,022,910	$ 15,466,236	$ 17,055,539	$ 18,845,635	$ 18,537,281	$ 17,616,246	$ 18,946,392	$ 16,036,364	$ 17,156,543	$ 207,053,445
37	Actual Basic Charge Revenue/Test Year Existing	(28) - (32)	$ 1,711,699	$ 1,666,204	$ 1,699,799	$ 1,693,425	$ 1,685,619	$ 1,746,591	$ 1,718,059	$ 1,706,117	$ 1,702,993	$ 1,721,002	$ 1,670,380	$ 1,702,427	$ 20,424,314
38	Actual Usage (kWhs)/Test Year Existing	(26) - (30)	179,782,076	168,654,118	169,349,462	137,900,086	147,018,878	161,866,102	183,645,251	178,359,075	168,045,244	182,442,206	147,533,281	162,916,858	1,987,512,637
39	Retail Revenue Credit ($/kWh)	Attachment 3, Page 1	$ 0.01900	$ 0.01900	$ 0.01900	$ 0.01895	$ 0.01895	$ 0.01895	$ 0.01895	$ 0.01895	$ 0.01895	$ 0.01895	$ 0.01895	$ 0.01895	
40	Variable Power Supply Payments	(38) x (39)	$ 3,415,859	$ 3,204,428	$ 3,217,640	$ 2,613,207	$ 2,786,008	$ 3,067,363	$ 3,480,078	$ 3,379,904	$ 3,184,457	$ 3,457,280	$ 2,795,756	$ 3,087,274	$ 37,689,254
41	Customer Decoupled Payments	(36) - (37) -(40)	$ 12,884,284	$ 12,280,985	$ 12,289,401	$ 10,716,278	$ 10,994,609	$ 12,241,586	$ 13,647,499	$ 13,451,260	$ 12,728,796	$ 13,768,110	$ 11,570,228	$ 12,366,842	$ 148,939,878
42	Non-Residential Revenue Per Customer Received	(41) / (33)	$343.75	$331.55	$327.52	$293.17	$304.42	$331.96	$374.10	$371.34	$349.63	$377.91	$319.28	$339.56	$4,063.90
43	Deferral - Surcharge (Rebate)	(35) - (41)	$ 601,994	$ 196,633	$ 718,452	$ 1,549,340	$ 2,067,948	$ 1,624,432	$ 1,443,683	$ 925,206	$ 108,341	$ 62,678	$ 1,585,275	$ 690,721	$ 11,574,703
44	Deferral - Revenue Related Expenses	Rev Conv Factor	$ (28,099)	$ (9,178)	$ (33,535)	$ (68,743)	$ (91,753)	$ (72,074)	$ (64,055)	$ (41,050)	$ (4,807)	$ (2,781)	$ (70,337)	$ (30,647)	$ (517,059)
45		FERC Rate	4.96%	4.96%	4.96%	4.75%	4.75%	4.75%	3.43%	3.43%	3.43%	3.25%	3.25%	3.25%	
46	Interest on Deferral	Avg Balance Calc	$ 1,186	$ 2,764	$ 4,579	$ 8,689	$ 15,565	$ 22,610	$ 20,582	$ 23,876	$ 25,356	$ 24,315	$ 26,514	$ 29,531	$ 205,566
47	**Monthly Non-Residential Deferral Totals**		**$ 575,081**	**$ 190,219**	**$ 689,495**	**$ 1,489,286**	**$ 1,991,760**	**$ 1,574,968**	**$ 1,400,210**	**$ 908,032**	**$ 128,890**	**$ 84,212**	**$ 1,541,451**	**$ 689,605**	**$ 11,263,209**
48	Cumulative Deferral (Rebate)/Surcharge Balance	Σ((43) ,(44) , (46))	$ 575,081	$ 765,300	$ 1,454,795	$ 2,944,082	$ 4,935,842	$ 6,510,810	$ 7,911,019	$ 8,819,051	$ 8,947,941	$ 9,032,153	$ 10,573,605	**$ 11,263,209**	
49	**Total Cumulative Deferral (Rebate)/Surcharge Balance**	**#REF!**	$ 2,362,253	$ 3,152,942	$ 3,661,437	$ 4,901,223	$ 7,627,060	$ 9,501,441	$ 9,871,198	$ 10,145,858	$ 9,412,838	$ 9,436,658	$ 10,241,948	**$ 10,452,475**	

**** - As approved in Docket No. UE-190334, the Company is required to calculate decoupled revenue using YTD average customers, compare to what was recorded using monthly customer counts, and record the difference in December so that the annual decoupled revenue is based on YTD average customers. This amount includes that annual true-up that resulted in an increase to decoupled revenue of $262.05.**

Table 1-8: 2020 Annual True-Up for Electric Residential and Electric Non-Residential.

Purpose: As required by UE-190334 (UE-190222, consolidated) paragraph 111, the Company is required to calculate decoupled revenue using YTD average customers, compare to what was recorded using monthly customer counts, and record the difference so that the annual decoupled revenue is based on YTD average customers.

Procedure: Separately for residential and non-residential, calculated YTD average decoupled (test year existing) customers and multiplied that by the sum of decoupled revenue per customer by month to calculate total decoupled revenue for the period based on YTD average customers (for 2020, the YTD was from April through December as the order was effective 4/1/2020). This was compared to the amount recorded using monthly decoupled customers and monthly decoupled revenue per customer. The difference was recorded with the monthly decoupled revenue for December 2020.

Residential		
Average Decoupled Customers (average of line 9 in Deferral Calc for April-Dec 2020)		217,035
Sum of Decoupled Revenue per Customer (sum of line 10 in Deferral Calc for April-Dec 2020)		521.02
Total Decoupled Revenue using Average Decoupled Customers	$	113,080,451.53
Less April - November Decoupled Revenue (sum of line 11 in Deferral Calc for April-Nov 2020)		94,209,371.45
Decoupled Revenue to record for December to reflect true-up	$	18,871,080.08
December Decoupled Customers (line 9, column n in Deferral Calc)		217,558
December Decoupled Revenue per Customer (line 10, column n in Deferral Calc)	$	86.79
Total Decoupled Revenue for December using monthly decoupled customers	$	18,881,446.33
Net increase/(decrease) to Decoupled Revenue due to Average Calculation	$	(10,366.26)
Non-Residential		
Average Decoupled Customers (average of line 33 in Deferral Calc for April-Dec 2020)		36,416
Sum of Decoupled Revenue per Customer (sum of line 34 in Deferral Calc for April-Dec 2020)	$	3,337.58
Total Decoupled Revenue using Average Decoupled Customers	$	121,542,832.48
Less April - November Decoupled Revenue (sum of line 35 in Deferral Calc for April-Nov 2020)		108,485,269.60
Decoupled Revenue to record for December to reflect true-up	$	13,057,562.88
December Decoupled Customers (line 33, column n in Deferral Calc)		36,420
December Decoupled Revenue per Customer (line 34, column n in Deferral Calc)	$	358.52
Total Decoupled Revenue for December using monthly decoupled customers	$	13,057,300.82
Net increase/(decrease) to Decoupled Revenue due to Average Calculation	$	262.05

For Electric Residential service, the computations developed deferred revenue ($810,734) in the rebate direction (Table 1-6, Line 23, Total Column and copied to Table 1-9, 2020 Deferred Revenue). For the annual decoupling filing, adjustments (Table 1-9), including a Prior Year Carryover Balance of ($210,964) plus other adjustments produced a final rebate result of ($1,112,391).[21]

Table 1-9: 2020 Electric Residential Group Rate Determination.

Residential Electric Service: Adjustments		
2020 Deferred Revenue	$	(810,734)
Add: Earnings Sharing/DSM Adjustment	$	-
Add: Prior Year Carryover Balance	$	(210,964)
Add: Interest through 7/31/2024	$	(31,835)
Add: Revenue Related Expense Adjustment	$	(58,858)
Total Requested Recovery	$	(1,112,391)
Customer Surcharge Revenue	$	(1,112,391)
Carryover Deferred Revenue	$	-

For Non-Electric Residential service, the computations developed deferred revenue of $11,260,209 in the surcharge direction (Table 1-6, Line 48, Cumulative Deferrals (Rebate)/Surcharge Balance, Dec-20 Column, and copied to Table 1-10, 2020 Deferred Revenue). For the annual decoupling filing, adjustments (Table 1-10), including a Prior Year Carryover Balance of $2,433,164) plus other adjustments produced a Customer Surcharge Revenue amount of $14,489,389 plus a Carryover Deferred Revenue amount of $271,257.[22]

[21] Letter of Joe Miller, Senior Manager of Rates and Tariffs, Regulatory Affairs, Avista to Mark L. Johnson, Executive Director and Secretary, Washington Utilities and Transportation Commission, Re: Tariff WN U-28, Electric Service Electric Decoupling Rate Adjustment, May 26, 2021, Page 2 of 6.
[22] Letter of Joe Miller, Senior Manager of Rates and Tariffs, Regulatory Affairs, Avista to Mark L. Johnson, Executive Director and Secretary, Washington Utilities and Transportation Commission, Re: Tariff WN U-28, Electric Service Electric Decoupling Rate Adjustment, May 26, 2021, Page 3 of 6.

Table 1-10: 2020 Electric Non-Residential Group Rate Determination.

Non-Residential Electric Service: Adjustments		
2020 Deferred Revenue	$	11,263,209
Add: Earnings Sharing/DSM Adjustment	$	-
Add: Prior Year Carryover Balance	$	2,433,164
Add: Interest through 7/31/2024	$	445,414
Add: Revenue Related Expense Adjustment	$	618,839
Total Requested Recovery	$	14,760,626
Customer Surcharge Revenue	$	14,489,369
Carryover Deferred Revenue	$	271,257

Natural Gas Group 1 (Residential) and Group 2 (Non-Residential)

For natural gas *Decoupled Revenue per Customer (by Rate Group)* is developed following the steps in Schedule 175A.[23] Calculation of Decoupled Revenue per Customer is specified in seven steps. These steps are implemented for Residential Customers in Table 1-9 and for Non-Residential Customers in Table 1-10. Monthly Decoupled Revenue per Customer for Group 1: Residential and Group 2: Non-Residential are then used to develop the *Monthly Decoupling Deferral* for natural gas, following the steps in Schedule 175B.

<u>Natural Gas Decoupling Deferral (Schedule 175A)</u>

Step 1: Determine the Total Normalized Revenue. The Total Normalized Revenue is equal to the final approved base rate revenue approved in the Company's last general rate case, individually for each rate schedule. Table 1-9, Line 1 shows initial Total Normalized Net Revenue. In addition, Line 2 shows Allowed Revenue Decrease. The sum of Line 1 and Line 2 is shown on Line 3 as the Allowed Base Rate Revenue.

Step 2: Determine Variable Gas Supply Revenue. The product of Normalized Therms (Line 4) from the 2016 test year and PGA Rates (Line 5) is the Variable Gas Supply Revenue (Line 6).

Step 3: Determine Delivery Revenue. To determine the Delivery Revenue, the Variable Gas Supply Revenue (Line 6) is subtracted from the Total Normalized Revenue.

[23] Avista Corporation, dba Avista Utilities, Schedule 175A, Decoupling Mechanism – Natural Gas, Issued June 12, 2015, Effective August 1, 2015.

Step 4: Remove Basic Charge Revenue. Step 4 is to calculate the Basic Charge Revenue. Because the decoupling mechanism only tracks revenue that is included in the variable portion of the rate, revenue already allocated to the fixed portion of the rate (customer charge) is removed. Basic Charge Revenue is the product of the number of Customer Bills in the 2016 test year (Line 8) times the Settlement Basic Charges (Line 9). The result, Basic Charge Revenue, is shown on Line 10.[24]

Step 5: Determine Allowed Decoupled Revenue. The Allowed Decoupled Revenue is equal to the Delivery Revenue (from Line 7) minus the Basic Charge Revenue (Line 10). The resulting Decoupled Revenue is shown on Line 11.

Step 6: Determine the Allowed Decoupled Revenue per Customer. In Step 6, Decoupled Revenue from Line 11 is put on a per customer basis. The Decoupled Revenue (by Rate Group) is divided by the approved Rate Year number of customers (by Rate Group). This determines the annual Allowed Decoupled Revenue per Customer (by Rate Group) as shown in Table 1-10.

Step 7: Determine the Monthly Allowed Decoupled Revenue per Customer. This step converts the annual Allowed Decoupled Revenue per Customer (by Rate Group) into monthly values. The assignment of monthly values is carried out by modeling monthly therm use in relation to the annual therm use for the rate year. This modeling is shown in Table 1-11.

In Table 1-11, the therm use for Group 1 (Residential) is shown in Line 4 and for Group 2 (Non-Residential) in Line 8. Both monthly therm values and the annual therm values are shown. Below the monthly values, percentages (Lines 5 and 9) are shown. Lines 14 and 18 show the use of these percentages, applied to annual Allowed Decoupled Revenue per Customer to generate monthly values.

These monthly values are then used in the implementation of Schedule 175B.

[24] For natural gas minimum charges are treated like fixed charges.

Table 1-11. 2020 Development of Natural Gas Decoupled Revenue per Customer

Avista Utilities
Natural Gas Decoupling Mechanism
Development of Decoupled Revenue by Rate Schedule - Natural Gas
Washington Docket No. UG-170486 Compliance Filing

	TOTAL	RESIDENTIAL SCHEDULE 101/102	GENERAL SVC. SCH. 111/112/116	LG. GEN. SVC. SCH. 121/122/126	INTERRUPTIBLE SCH 131	SCHEDULES 132	SCHEDULES 146 & 148	Schedule 132
1 Total Normalized 12 ME Dec 2016 Revenue	$ 88,831,000	$ 67,622,000	$ 15,462,000	$ 1,024,000	$ -	$ 190,000	$ 4,533,000	$ 190,000
2 Allowed Revenue Decrease (Attachment 2)	$ (2,145,000)	$ (1,663,000)	$ (380,000)	$ (25,000)	$ -	$ (5,000)	$ (72,000)	$ (5,000)
3 Allowed Base Rate Revenue	$ 86,686,000	$ 65,959,000	$ 15,082,000	$ 999,000	$ -	$ 185,000	$ 4,461,000	$ 185,000
4 Normalized Therms (12ME Dec 2016 Test Year)	252,141,683	119,446,617	47,951,720	4,115,331	-	901,267	79,726,748	901,267
5 Schedule 150 PGA Rates excluded from base rates		$ -	$ -	$ -	$ -			$ -
6 Variable Gas Supply Revenue	$ -	$ -	$ -	$ -	$ -			$ -
7 Delivery Revenue (Ln 3 - Ln 6)	$ 82,040,000	$ 65,959,000	$ 15,082,000	$ 999,000	$ -			$ 185,000
8 Customer Bills (12ME Dec 2016 Test Year)	1,881,282	1,847,462	32,983	273	0	24	540	24
9 Allowed Basic / Minimum Charges		$9.50	$97.25	$240.44	$0.00			$ -
10 Basic Charge Revenue (Ln 8 * Ln 9)	$ 20,824,126	$ 17,550,889	$ 3,207,597	$ 65,640	$ -			$ -
11 Decoupled Revenue	$ 61,215,874	$ 48,408,111	$ 11,874,403	$ 933,360	$ -	Excluded From Decoupling		$ 185,000

	Residential	Non-Residential Group
12 Average Number of Customers (Line 8 / 12)	153,955	2,771
13 Annual Therms	119,446,617	52,067,051
14 Basic Charge Revenues	$ 17,550,889	$ 3,273,237
15 Customer Bills	1,847,462	33,256
16 Average Basic Charge	$9.50	$98.43

Attachment 5, Page 1 (UG-170486 Compliance Filing)

Table 1-12. 2020 Natural Gas Decoupled Revenue per Customer

Avista Utilities
Natural Gas Decoupling Mechanism
Development of Decoupled Revenue Per Customer - Natural Gas
Washington Docket No. UG-170486 Compliance Filing

Line No.		Source	Residential Schedules*	Non-Residential Schedules**
	(a)	(b)	(c)	(d)
1	Decoupled Revenues	Attachment 5, Page 1	$ 48,408,111	$ 12,807,763
2	Test Year # of Customers 12 ME12.2016	Revenue Data	153,955	2,771
3	Decoupled Revenue Per Customer	(1) / (3)	$ 314.43	$ 4,621.52

*Rate Schedules 101, 102.
**Rate Schedules 111, 112, 116, 121, 122, 126, 131.

Attachment 5, Page 2 (UG-170486 Compliance Filing)

Revenues		
From Revenue Per Customer	$ 48,408,123	$ 12,807,772
From Basic Charges	$ 17,550,889	$ 3,273,237
From Gas Supply	$ -	$ -
Total	$ 65,959,012	$ 16,081,009

Table 1-13. 2020 Development of Monthly Natural Gas Decoupled Revenue per Customer

Natural Gas Decoupling Mechanism
'Development of Monthly Decoupled Revenue Per Customer - Natural Gas
Washington Docket No. UG-170486 Compliance Filing

Line No.		Source	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	TOTAL
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
1															
2	**Natural Gas Delivery Volume**														
3	*Residential**														
4	- Weather-Normalized Therm Delivery Volume	Monthly Rate Year	21,124,002	16,814,801	13,702,397	8,379,182	4,880,475	3,154,867	2,296,193	2,357,534	3,002,764	7,503,054	14,548,064	21,683,284	119,446,617
5	- % of Annual Total	% of Total	17.68%	14.08%	11.47%	7.02%	4.09%	2.64%	1.92%	1.97%	2.51%	6.28%	12.18%	18.15%	100.00%
6															
7	*Non-Residential***														
8	- Weather-Normalized Therm Delivery Volume	Monthly Rate Year	7,263,564	6,455,069	5,655,268	3,958,871	3,051,972	2,050,065	1,757,090	1,837,589	2,247,269	4,164,398	5,571,304	8,054,593	52,067,051
9	- % of Annual Total	% of Total	13.95%	12.40%	10.86%	7.60%	5.86%	3.94%	3.37%	3.53%	4.32%	8.00%	10.70%	15.47%	100.00%
10															
11	**Monthly Decoupled Revenue Per Customer ("RPC")**														
12	*Residential**														
13	-UG-150205 Decoupled RPC	Attachment 5, P. 2 L. 3													$ 314.43
14	-Monthly Decoupled RPC	() x (13)	$ 55.61	$ 44.26	$ 36.07	$ 22.06	$ 12.85	$ 8.30	$ 6.04	$ 6.21	$ 7.90	$ 19.75	$ 38.30	$ 57.08	$ 314.43
15															
16	*Non-Residential***														
17	-UG-150205 Decoupled RPC	Attachment 5, P. 2 L. 3													$ 4,621.52
18	-Monthly Decoupled RPC	() x (17)	$ 644.72	$ 572.96	$ 501.97	$ 351.39	$ 270.90	$ 181.97	$ 155.96	$ 163.11	$ 199.47	$ 369.64	$ 494.51	$ 714.93	$ 4,621.52
19															
20	*Rate Schedules 101, 102.														
21	**Rate Schedules 111, 112, 116, 121, 122, 126, 131.														

Attachment 5, Page 2 (UG-170486 Compliance Filing)

Natural Gas Monthly Decoupling Deferral
Schedule 175B specifies the method for developing the *Monthly Decoupling Deferral* for natural gas service. The calculation of the monthly natural gas decoupling deferral for 2020 is shown in Table 1-14 for Gas Residential and in Table 1-15 for Gas Non-Residential. The monthly decoupling deferral amounts across 2020 sum to the annual total decoupling deferral for 2020.

The Schedule 175B calculation steps for Natural Gas Residential follow. There are eight steps. The sequence of the line numbers in Table 1-14 are keyed to the eight steps. Steps 1 through 5 are required to remove new customers (new hookups) from the calculation.

Natural Gas – Residential (Schedule 175B)

Step 1: Deduct new hookup customers. New hookup customers (Line 5) are deducted from total actual number of customers (Line 1) to determine the actual number of test year existing customers each month. The result (actual test year number of decoupled customers after subtracting out new customers) is shown on Line 9.

Step 2: Calculate total Allowed Decoupled Revenue each month. This is calculated by multiplying the number of Actual Customers after removing new customers (Line 9) by the Monthly Decoupled Revenue per Customer (Line 10). The result is shown on Line 11, Decoupled Revenue.

Step 3: Deduct actual new hookup customer revenue from total actual revenue. This determines the actual test year existing customer revenue collected in the applicable month. To form this result, Actual Base Rate Revenue (Line 3) is adjusted by subtracting New Customer Base Rate Revenue (Line 7). The result is shown on Line 12.

Step 4: Deduct actual new hookup customer fixed charge revenue from total actual fixed charge revenue. Line 8, New Customer Basic Charge Revenue, is subtracted from Line 4, Actual Basic Charge Revenue. The result, Actual Basic Charge Revenue (Test Year Existing), is shown on Line 13.

Step 5: Deduct actual new hookup customer kWh sales from total actual kWh sales. This is Line 2 (Actual Usage kWh) minus Line 6 (New Customer Usage (kWh). The result is the Actual Usage (kWh)/Test Year Existing (Line 14) from which new customer (new hookups) actual usage has been removed. Then, Actual Usage (kWh)/Test Year Existing in Line 14 is multiplied by the approved Retail Revenue Credit (Line 15). The result is the revenue collected related to the variable power supply (Variable Power Supply Payments;

Line 16). When Step 5 is completed, all quantities remaining in the analysis have been adjusted to remove new customers (new hookups).

Step 6: Compute Customer Decoupled Payments. Actual Decoupled Revenue is calculated by subtracting the Actual Basic Charge Revenue/Test Year Existing in Line 13 and the Variable Power Supply Payments (Line 15) from the Actual Base Rate Revenue/Test Year Existing (Line 12). Customer Decoupled Payments is shown on Line 17.

Step 7: Compute Balance to be Deferred by the Company as a Surcharge or as a Rebate. The Balance (for each month) is computed by subtracting Customer Decoupled Payments (Line 15) from Decoupled Revenue (Line 11).[25] The result (Deferral – Surcharge/Rebate) is shown on Line 19.

This amount is then adjusted for Revenue Related Expenses (Line 20) and for interest at the FERC rate (FERC interest rate at Line 21 and interest at Line 22). The result is the Monthly Electric Residential Deferral Total (Line 23).

These monthly amounts are then cumulated in Line 24. The Total Cumulative Deferral (Rebate)/Surcharge Balance is tracked in Line 48. The total cumulative deferral for Natural Gas Residential is a decoupling surcharge to customers of $1,174,438.[26]

Step 8: Comparison. At the end of every 12-month deferral period, the annual decoupled revenue per customer, by rate group, is multiplied by the average annual number of actual test year existing customers. The result of that calculation is compared to the actual deferred revenue for the same 12-month period. The difference between the actual deferred revenue, and the calculated value, is then added to, or subtracted from, the total deferred balance by Rate Group. This calculation is shown in Table 1-12.

[25] In Table 1-14, the source for Deferral - Surcharge (Rebate) is listed as (12) – (15). The source should be corrected to (11) – (15). The calculated value, however, is correct.
[26] Table 1-14, line 24, (Rebate/Surcharge) Balance, last column.

Table 1-14: 2020 Natural Gas Decoupling - Residential.

Decoupling Mechanism - UG-170486 Base effective 5/1/2018,
UG-190335 Base effective 4/1/2020
Development of WA Natural Gas Deferrals (Calendar Year 2020)

Line No.		Source	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Total
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
	Residential Group														
1	Actual Customers	Revenue System				167,876	167,226	168,009	168,008	167,867	168,830	168,858	168,988	169,632	
2	Actual Usage ("Therms)	Revenue System				8,680,515	5,177,292	3,321,590	2,633,258	2,239,101	2,847,296	8,977,249	17,157,823	21,531,818	
3	Actual Base Rate Revenue	Revenue System				$ 5,252,399	$ 3,776,495	$ 3,000,532	$ 2,761,937	$ 2,607,616	$ 2,797,558	$ 5,409,453	$ 9,409,133	$ 11,826,570	
4	Actual Fixed Charge Revenue	Revenue System				$ 1,613,347	$ 1,609,140	$ 1,623,885	$ 1,623,370	$ 1,621,147	$ 1,628,022	$ 1,627,063	$ 1,625,840	$ 1,629,450	
5	New Customers	Revenue System				4,208	4,233	4,349	4,745	4,977	5,290	5,449	5,715	5,901	
6	New Customer Usage (Therms)	Revenue System				268,677	120,936	82,419	54,756	35,744	44,185	100,287	370,194	614,291	
7	New Customer Base Rate Revenue	Revenue System				$ 153,301	$ 92,622	$ 77,767	$ 69,541	$ 62,486	$ 69,408	$ 94,795	$ 219,659	$ 343,301	
8	New Customer Fixed Charge Revenue	Revenue System				$ 40,632	$ 41,054	$ 42,532	$ 45,847	$ 47,225	$ 50,372	$ 51,661	$ 54,543	$ 56,079	
9	Actual/Test Year Existing Customers	(1) - (5)	167,769	167,465	167,740	163,668	162,993	163,660	163,263	162,890	163,540	163,409	163,273	163,731	1,973,401
10	Monthly Decoupled Revenue per Customer	Attachment 4, Page 3	$55.61	$44.26	$36.07	$27.53	$16.27	$8.72	$6.48	$6.25	$8.69	$24.18	$45.05	$63.77	$342.87
11	Decoupled Revenue	(9) x (10)	$ 9,329,063	$ 7,412,520	$ 6,050,389	$ 4,505,527	$ 2,652,551	$ 1,426,598	$ 1,057,715	$ 1,018,372	$ 1,421,151	$ 3,950,883	$ 7,355,157	$ 10,420,882 *	$ 56,600,806
12	Actual Usage /Test Year Existing	(2) - (6)	19,902,225	18,156,995	16,737,084	8,411,838	5,056,357	3,239,171	2,578,501	2,203,357	2,803,112	8,876,962	16,787,629	20,917,527	125,670,758
13	Actual Base Rate Revenue / Test Year Existing	(3) - (7)	$ 11,069,164	$ 9,201,681	$ 8,457,284	$ 5,099,098	$ 3,683,872	$ 2,922,766	$ 2,692,396	$ 2,545,130	$ 2,728,150	$ 5,314,659	$ 9,189,474	$ 11,483,269	$ 74,386,943
14	Actual Fixed Charge Revenue / Test Year Existing	(4) - (8)	$ 1,611,951	$ 1,607,724	$ 1,613,623	$ 1,572,716	$ 1,568,086	$ 1,581,354	$ 1,577,523	$ 1,573,922	$ 1,577,650	$ 1,575,402	$ 1,571,297	$ 1,573,371	$ 19,004,616
15	Customer Decoupled Payments	(13) - (14)	$ 9,457,214	$ 7,593,958	$ 6,843,662	$ 3,526,383	$ 2,115,787	$ 1,341,412	$ 1,114,873	$ 971,208	$ 1,150,500	$ 3,739,257	$ 7,618,177	$ 9,909,898	$ 55,382,328
16	Residential Revenue Per Customer Received	(15) / (9)	$56.37	$45.35	$40.80	$21.55	$12.98	$8.20	$6.83	$5.96	$7.03	$22.88	$46.66	$60.53	
17	Deferral - Surcharge (Rebate)	(12) - (15)	$ (128,150)	$ (181,437)	$ (793,272)	$ 979,144	$ 536,764	$ 85,185	$ (57,158)	$ 47,164	$ 270,651	$ 211,626	$ (263,021)	$ 510,984	$ 1,218,479
18	Deferral - Revenue Related Expenses	Rev Conv Factor	$ 5,955	$ 8,430	$ 36,859	$ (43,234)	$ (23,701)	$ (3,761)	$ 2,524	$ (2,083)	$ (11,951)	$ (9,344)	$ 11,614	$ (22,562)	$ (51,254)
19		FERC Rate	4.96%	4.96%	4.96%	4.75%	4.75%	4.75%	3.43%	3.43%	3.43%	3.25%	3.25%	3.25%	
20	Interest on Deferral	Avg Balance Calc	$ (253)	$ (864)	$ (2,788)	$ (2,326)	$ 533	$ 1,711	$ 1,279	$ 1,269	$ 1,707	$ 2,246	$ 2,186	$ 2,513	$ 7,214
21	**Monthly Residential Deferral Totals**		**$ (122,449)**	**$ (173,870)**	**$ (759,201)**	**$ 933,584**	**$ 513,596**	**$ 83,135**	**$ (53,355)**	**$ 46,350**	**$ 260,407**	**$ 204,528**	**$ (249,221)**	**$ 490,934**	**$ 1,174,438**
22	Cumulative Deferral (Rebate) Balance	Σ((17) ,(18) , (20))	$ (122,449)	$ (296,319)	$ (1,055,520)	$ (121,936)	$ 391,661	$ 474,796	$ 421,441	$ 467,791	$ 728,198	$ 932,726	$ 683,504	**$ 1,174,438**	

*** As approved in Docket No. UG-190335, the Company is required to calculate decoupled revenue using YTD average customers, compare to what was recorded using monthly customer counts, and record the difference in December so that the annual decoupled revenue is based on YTD average customers. This amount includes that annual true-up that resulted in a decrease to decoupled revenue of $19,742.07.**

The result of these calculations is that for the gas residential group, deferred revenue for 2020 is decoupling surcharge of $1,174,438[27],

[27] Table 1-14, Line 22, Cumulative Deferral (Rebate)/Surcharge Balance, Dec-20 Column.

Natural Gas – Non-Residential (Schedule 175B)

Schedule 175B calculation for Electric Non-Residential steps follow. There are eight steps. The sequence of the line numbers are keyed to the eight steps. Steps 1 through 5 are required to remove new customers (new hookups) from the calculation.

Step1: Deduct new hookup customers. New hookup customers (Line 29) are deducted from the total actual number of customers (Line 25) to determine the actual number of test year existing customers each month. The result (actual number of customers after subtracting out new customers) is in Line 33.

Step 2: Calculate total Allowed Decoupled Revenue each month. This is calculated by multiplying the number of Actual Customers after removing new customers (Line 33) by the Monthly Decoupled Revenue per Customer (Line 34). The result is shown on Line 35.

Step 3: Deduct actual new hookup customer revenue from total actual revenue. This determines the actual test year existing customer revenue collected in the applicable month. To form this result, Actual Base Rate Revenue (Line 27) is adjusted by subtracting New Customer Base Rate Revenue (Line 31). The result is shown on Line 36.

Step 4: Deduct actual new hookup customer fixed charge revenue from total actual fixed charge revenue. Line 32, New Customer Basic Charge Revenue, is subtracted from Line 28, Actual Basic Charge Revenue. The result, Actual Basic Charge Revenue (Test Year Existing), is shown on Line 37.

Step 5: Deduct actual new hookup customer kWh sales from total actual kWh sales. This is Line 26 (Total Actual kWh Sales) minus Line 30 (New Customer Usage (kWh). The result is the Actual Usage (kWh) from which new customer actual usage has been removed. The result is shown in Line 38. Then, Actual Usage (kWh) in Line 38 is multiplied by the approved Retail Revenue Credit (Line 39). The result is the revenue collected related to the variable power supply (Variable Power Supply Payments in Line 40). When Step 5 is completed, all remaining quantities have been adjusted to remove new customers (new hookups).

Step 6: Compute Customer Decoupled Payments. Actual Decoupled Revenue is calculated by subtracting the Actual Basic Charge Revenue (Test Year Existing) in Line 37 and the Variable Power Supply Payments (Line 40) from the Actual Base Rate Revenue (Line 36) and is shown on Line 41.

Step 7: Compute Balance to be Deferred by the Company as a Surcharge or as a Rebate. The Balance (for each month) is computed by subtracting Customer Decoupled Payments (Line 41) from Decoupled Revenue (Line 35). The result (Deferral – Surcharge/Rebate) is shown on Line 43. This amount is then adjusted for Revenue Related Expenses (Line 44) and for interest at the FERC rate (Lines 44 and 45). The result is the Monthly Non-Residential Deferral Total (Line 47). These monthly amounts are cumulated in Line 48

Monthly Residential Deferral Total for each month is shown just below Line 12. This is the difference between the Actual Decoupled Revenue (Step 6; Line 9) and the Allowed Decoupled Revenue (Step 2; Line 3) plus any interest on the deferral. The Total Cumulative Deferral (Rebate)/Surcharge Balance is tracked in Line 48. The total cumulative deferral for Natural Gas Non-Residential is a surcharge to customers of $11,263,209.[28]

Step 8: Comparison. At the end of every 12-month deferral period, the annual decoupled revenue per customer, by rate group, will be multiplied by the average annual number of actual test year existing customers. The results of that calculation will be compared to the actual deferred revenue for the same 12-month period. The difference between the actual deferred revenue and the calculated value will be added to, or subtracted from, the total deferred balance by Rate Group. This calculation is shown in Table 1-16, and results in a decrease of $19,742.07 for the Residential Group and a decrease of $12,689.42 for the Non-Residential Group.[29]

[28] Table 1-15, line 48, Cumulative Deferral (Rebate/Surcharge) Balance.
[29] Table 1-16, Net increase (decrease) to Decoupled Revenue due to Average Calculation (middle of table for Residential; bottom line for Non-Residential).

Table 1-15: 2020 Natural Gas Decoupling - Non-Residential.

Decoupling Mechanism - UG-170486 Base effective 5/1/2018, UG-190335 Base effective 4/1/2020
Development of WA Natural Gas Deferrals (Calendar Year 2020)

Line No.		Source	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Total
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
	Non-Residential Group														
23	Actual Customers	Revenue System				3,153	3,122	3,159	3,148	3,122	3,151	3,156	3,158	3,173	
24	Actual Usage ("Therms)	Revenue System				3,634,382	2,904,968	1,882,576	1,780,378	1,674,515	2,068,491	4,988,126	5,823,340	7,851,509	
25	Actual Base Rate Revenue	Revenue System				$ 1,271,852	$ 1,057,694	$ 769,948	$ 753,247	$ 745,621	$ 839,523	$ 1,642,483	$ 1,906,840	$ 2,470,331	
26	Actual Fixed Charge Revenue	Revenue System				$ 322,894	$ 336,113	$ 340,494	$ 339,112	$ 336,676	$ 340,191	$ 340,207	$ 339,539	$ 341,752	
27	New Customers	Revenue System				41	38	38	38	42	37	36	44	42	
28	New Customer Usage (Therms)	Revenue System				108,540	55,253	35,573	22,680	15,266	17,847	28,994	73,866	142,469	
29	New Customer Base Rate Revenue	Revenue System				$ 32,149	$ 18,348	$ 13,156	$ 9,775	$ 7,889	$ 8,345	$ 11,208	$ 23,820	$ 41,807	
30	New Customer Fixed Charge Revenue	Revenue System				$ 4,090	$ 3,928	$ 4,109	$ 4,087	$ 4,252	$ 3,980	$ 3,829	$ 3,860	$ 4,510	
31	Test Year Existing Customers	(23) - (27)	3,142	3,158	3,147	3,112	3,084	3,121	3,110	3,080	3,114	3,120	3,114	3,131	37,433
32	Monthly Decoupled Revenue per Customer	Attachment 5, Page 3	$644.72	$572.96	$501.97	$402.99	$292.00	$212.46	$153.39	$167.80	$199.69	$364.00	$552.49	$675.30	$4,739.76
33	Decoupled Revenue	(31) x (32)	$ 2,025,712	$ 1,809,401	$ 1,579,690	$ 1,254,106	$ 900,513	$ 663,088	$ 477,029	$ 516,836	$ 621,830	$ 1,135,675	$ 1,720,466	$ 2,101,686 **	$ 14,806,033
34	Actual Usage (Therms) /Test Year Existing	(24) - (28)	8,048,135	7,886,250	7,168,311	3,525,842	2,849,715	1,847,002	1,757,698	1,659,248	2,050,644	4,959,132	5,749,475	7,709,040	55,210,492
35	Actual Base Rate Revenue / Test Year Existing	(25) - (29)	$ 2,616,090	$ 2,269,383	$ 2,087,429	$ 1,239,703	$ 1,039,346	$ 756,791	$ 743,471	$ 737,732	$ 831,177	$ 1,631,275	$ 1,883,020	$ 2,428,524	$ 18,263,942
36	Actual Fixed Charge Revenue / Test Year Existing	(26) - (30)	$ 306,762	$ 308,694	$ 307,626	$ 318,804	$ 332,186	$ 336,385	$ 335,025	$ 332,424	$ 336,211	$ 336,378	$ 335,679	$ 337,242	$ 3,923,415
37	Customer Decoupled Payments	(35) - (36)	$ 2,309,327	$ 1,960,689	$ 1,779,803	$ 920,899	$ 707,160	$ 420,406	$ 408,447	$ 405,308	$ 494,966	$ 1,294,897	$ 1,547,342	$ 2,091,282	$ 14,340,526
38	Non-Residential Revenue Per Customer Rece	(37) / (31)	$734.99	$620.86	$565.56	$295.92	$229.30	$134.70	$131.33	$131.59	$158.95	$415.03	$496.90	$667.93	
39	Deferral - Surcharge (Rebate)	(33) - (37)	$ (283,615)	$ (151,287)	$ (200,113)	$ 333,207	$ 193,352	$ 242,682	$ 68,582	$ 111,528	$ 126,864	$ (159,222)	$ 173,124	$ 10,404	$ 465,506
40	Deferral - Revenue Related Expenses	Rev Conv Factor	$ 13,178	$ 7,030	$ 9,298	$ (14,713)	$ (8,537)	$ (10,716)	$ (3,028)	$ (4,925)	$ (5,602)	$ 7,030	$ (7,644)	$ (459)	$ (19,088)
41		FERC Rate	4.96%	4.96%	4.96%	4.75%	4.75%	4.75%	3.43%	3.43%	3.43%	3.25%	3.25%	3.25%	
42	Interest on Deferral	Avg Balance Calc	$ (559)	$ (1,418)	$ (2,117)	$ (1,783)	$ (794)	$ 28	$ 446	$ 693	$ 1,021	$ 928	$ 948	$ 1,189	$ (1,418)
43	**Monthly Non-Residential Deferral Totals**		**$ (270,996)**	**$ (145,676)**	**$ (192,931)**	**$ 316,712**	**$ 184,021**	**$ 231,994**	**$ 65,999**	**$ 107,297**	**$ 122,283**	**$ (151,264)**	**$ 166,428**	**$ 11,133**	**$ 445,001**
44	Cumulative Deferral (Rebate) Balance	Σ((39) ,(40) , (42))	$ (270,996)	$ (416,672)	$ (609,603)	$ (292,892)	$ (108,870)	$ 123,124	$ 189,124	$ 296,420	$ 418,703	$ 267,439	$ 433,867	**$ 445,001**	
45	**Total Cumulative Deferral (Rebate)**	**(22) + (44)**	$ (393,444)	$ (712,991)	$ (1,665,123)	$ (414,827)	$ 282,791	$ 597,920	$ 610,564	$ 764,211	$ 1,146,901	$ 1,200,165	$ 1,117,372	**$ 1,619,439**	

**** As approved in Docket No. UG-190335, the Company is required to calculate decoupled revenue using YTD average customers, compare to what was recorded using monthly customer counts, and record the difference in December so that the annual decoupled revenue is based on YTD average customers. This amount includes that annual true-up that resulted in a decrease to decoupled revenue of $12,689.42.**

The result of these calculations for the natural gas Non-Residential group is a decoupling surcharge to customers of $445,001.[30]

[30] Table 1-15, Line 48, Cumulative Deferral (Rebate) Surcharge Balance, Dec-20 Column.

Table 1-16: 2020 Annual December True-Up for Gas Residential and Non-Residential.

Purpose: As required by UG-190335 (UE-190222, consolidated) paragraph 111, the Company is required to calculate decoupled revenue using YTD average customers, compare to what was recorded using monthly customer counts, and record the difference so that the annual decoupled revenue is based on YTD average customers.

Procedure: Separately for residential and non-residential, calculated YTD average decoupled (test year existing) customers and multiplied that by the sum of decoupled revenue per customer by month to calculate total decoupled revenue for the period based on YTD average customers (for 2020, the YTD was from April through December as the order was effective 4/1/2020). This was compared to the amount recorded using monthly decoupled customers and monthly decoupled revenue per customer. The difference was recorded with the monthly decoupled revenue for December 2020.

Residential		
Average Decoupled Customers (average of line 9 in Deferral Calc for April-Dec 2020)		163,381
Sum of Decoupled Revenue per Customer (sum of line 10 in Deferral Calc for April-Dec 2020)	$	206.93
Total Decoupled Revenue using Average Decoupled Customers	$	33,808,833.58
Less April - November Decoupled Revenue (sum of line 11 in Deferral Calc for April-Nov 2020)		23,387,952.06
Decoupled Revenue to record for December to reflect true-up	$	10,420,881.52
December Decoupled Customers (line 9, column n in Deferral Calc)		163,731
December Decoupled Revenue per Customer (line 10, column n in Deferral Calc)	$	63.77
Total Decoupled Revenue for December using monthly decoupled customers	$	10,440,623.59
Net increase/(decrease) to Decoupled Revenue due to Average Calculation	$	(19,742.07)
Non-Residential		
Average Decoupled Customers (average of line 33 in Deferral Calc for April-Dec 2020)		3,110
Sum of Decoupled Revenue per Customer (sum of line 34 in Deferral Calc for April-Dec 2020)	$	3,020.12
Total Decoupled Revenue using Average Decoupled Customers	$	9,391,229.07
Less April - November Decoupled Revenue (sum of line 35 in Deferral Calc for April-Nov 2020)		7,289,542.62
Decoupled Revenue to record for December to reflect true-up	$	2,101,686.45
December Decoupled Customers (line 33, column n in Deferral Calc)		3,131
December Decoupled Revenue per Customer (line 34, column n in Deferral Calc)	$	675.30
Total Decoupled Revenue for December using monthly decoupled customers	$	2,114,375.87
Net increase/(decrease) to Decoupled Revenue due to Average Calculation	$	(12,689.42)

The result of these calculations is that for the gas Residential Group, deferred revenue for 2020 is in the surcharge direction with a decoupling surcharge of $1,174,438[31]. Adjustments, conveyed in the annual filing, result in a final Residential surcharge of $1,256,386, including a prior year carryover offset of ($13,216) and other adjustments (Table 1-15).[32]

Table 1-17: 2020 Natural Gas Residential Group Rate Determination.

Residential Natural Gas Service: Adjustments		
2020 Deferred Revenue	$	1,174,438
Add: Earnings Sharing/DSM Adjustment	$	-
Add: Prior Year Carryover Balance	$	(13,216)
Add: Interest through 7/31/2024	$	40,677
Add: Revenue Related Expense Adjustment	$	54,487
Total Requested Recovery	$	1,256,386
Customer Surcharge Revenue	$	801,749
Carryover Deferred Revenue	$	-

For the natural gas Non-Residential group, deferred revenue is in the surcharge direction with a decoupling surcharge to customers of $445,001.[33] Adjustments, conveyed in the annual filing, result in a final Non-Residential surcharge of $494,874 (Table 1-18).[34,35]

Table 1-18: 2020 Natural Gas Non-Residential Rate Determination.

Non-Residential Natural Gas Service: Adjustments		
2020 Deferred Revenue	$	445,001
Add: Earnings Sharing/DSM Adjustment	$	-
Add: Prior Year Carryover Balance	$	12,745
Add: Interest through 7/31/2024	$	15,564
Add: Revenue Related Expense Adjustment	$	21,563
Total Requested Recovery	$	494,873
Customer Surcharge Revenue	$	494,873
Carryover Deferred Revenue	$	-

[31] Table 1-14, Line 22, Cumulative Deferral (Rebate)/Surcharge Balance, Dec-20 Column
[32] Letter, re: Tariff WN U-29, Natural Gas Service Decoupling Rate Adjustment from Joe Miller, Avista Senior Manager for Rates and Tariffs, Regulatory Affairs to Mark L. Johnson, Executive Director and Secretary, Washington Utilities and Transportation Commission dated May 26, 2021, P. 2 of 5.
[33] Table 1-15, Line 48, Cumulative Deferral (Rebate) Surcharge Balance, Dec-20 Column.
[34] Letter, re: Tariff WN U-29, Natural Gas Service Decoupling Rate Adjustment from Joe Miller, Avista Senior Manager for Rates and Tariffs, Regulatory Affairs to Mark L. Johnson, Executive Director and Secretary, Washington Utilities and Transportation Commission dated May 26, 2021, P. 2 of 5.
[35] Total Requested Recovery in Table 1-16 is off by one dollar, due to a rounding difference.

Earnings Test 2020

The decoupling mechanism, in Schedules 75D and 175D, provides for application of an earnings test, separately for electric service and for natural gas.

Schedule 75D – Electric Earnings Test

According to Schedule 75D, the decoupling mechanism for Electric is subject to an annual earnings test based on the Company's year-end Commission Basis Reports that reflect actual decoupling-related revenues and various normalizing adjustments. As shown in Table 1-19, Line 3, the calculated rate of return on a normalized[36] basis in 2020 is 6.39%. This is lower than the Base rate of return authorized, so there are no Excess Earnings (Line 6).

Table 1-19. 2020 Electric Earnings Test.

	2020 Commission Basis Earnings Test for Decoupling		
Line No.			Electric
1	Rate Base		$ 1,700,977,000
2	Net Income		$ 108,650,000
3	Calculated ROR		6.39%
4	Base ROR	Pro-rated	7.28%
5	Excess ROR		-0.89%
6	Excess Earnings		$ -
7	Conversion Factor		0.756050
8	Excess Revenue (Excess Earnings/CF)		$ -
9	Sharing %		50%
10	2020 Total Earnings Test Sharing		**$ -**

Since the normalized return is less than the allowed return, the Earnings Test has no effect for electric customers for 2020.

[36] "Normalized" in this context means normalized to the commission basis earnings test (it does not refer to weather normalization, a different use of the same term).

Schedule 175D – Natural Gas Earnings Test

According to Schedule 175D, the decoupling mechanism for natural gas is subject to an annual earnings test based on the Company's year-end Commission Basis Reports that reflect actual decoupling-related revenues and various normalizing adjustments. As shown in Table 1-16, the rate of return on a normalized basis in 2020 is 6.08%. This is less than the allowed return. Since the normalized return is less than the allowed return, the Earnings Test has no effect for natural gas customers for 2020.

Table 1-20: 2020 Natural Gas Earnings Test.

	2020 Commission Basis Earnings Test for Decoupling		
Line No.			Natural Gas
1	Rate Base		$ 410,952,000
2	Net Income		$ 24,969,000
3	Calculated ROR		6.08%
4	Base ROR	Pro-rated	7.28%
5	Excess ROR		-1.21%
6	Excess Earnings		$ -
7	Conversion Factor		0.756218
8	Excess Revenue (Excess Earnings/CF)		$ -
9	Sharing %		50%
10	2019 Total Earnings Test Sharing		**$ -**

Three-Percent Annual Rate Increase Limitation 2020

Decoupling annual rate adjustment surcharges are subject to a 3% annual rate increase limitation (there is no reciprocal limit on rebate rate adjustments). The test is to divide the *incremental* annual revenue to be collected (proposed surcharge revenue minus present surcharge revenue) by the total "normalized" revenue for the two Rate Groups for the most recent January through December.

Normalized revenue is determined by multiplying the weather-corrected usage for the period by the present rates in effect. If the incremental amount of the proposed surcharge exceeds 3%, only a 3% incremental rate increase will apply. Any remaining deferred revenue will be carried over to the following years.

Schedule 75E – Electric 3% Rate Increase Test

The Electric Incremental Surcharge Test is shown in Table 1-17. Specifications for the test limit the surcharge to 3%, with any remainder deferred to the following year. For Residential customers, the result for the Incremental Decoupling Recovery Rate is negative (Line 7), so there is no Carryover Deferred Revenue.

For Non-Residential customers, the Incremental Surcharge result is 3.14% (Line 7), which is 0.14% above the 3% limit. Accordingly, the Adjusted Incremental Surcharge for Non-Residential Electric is set at 3% (Line 12) and there is Carryover Deferred Revenue for Non-Residential Electric. Following adjustments specified in the letter of Joe Miller, Senior Manager of Rates and Tariffs, Regulatory Affairs, Avista to Mark L. Johnson, Executive Director and Secretary, Washington Utilities and Transportation Commission of May 26, 2021, Table on Page 3 of 6, the Carryover is $271.257.

Table 1-21: 2020 Electric 3% Annual Rate Increase Limitation.

Line No.	**3% Incremental Surcharge Test**	Residential	Non-Residential
1	Revenue From 2020 Normalized Loads and Customers at Present Billing Rates (Note 1)	$ 239,238,066	$ 223,195,803
2	August 2021 - July 2022 Usage (kWhs)	2,471,980,588	2,133,927,654
3	Proposed Decoupling Recovery Rates	-$0.00045	$0.00693
4	Present Decoupling Surcharge Recovery Rates	$0.00244	$0.00365
5	Incremental Decoupling Recovery Rates	-$0.00289	$0.00328
6	Incremental Decoupling Recovery	$ (7,144,024)	$ 6,999,283
7	Incremental Surcharge %	**-2.99%**	**3.14%**
8	3% Test Adjustment (Notes 2)	$ -	$ (303,409)
9	3% Test Rate Adjustment	$0.00000	-$0.00014
10	Adjusted Proposed Decoupling Recovery Rates	-$0.00045	$0.00679
11	Adjusted Incremental Decoupling Recovery	$ (7,144,024)	$ 6,700,533
12	Adjusted Incremental Surcharge %	**-2.99%**	**3.00%**
	Notes		
	(1) Revenue from 2020 normalized loads and customers at present billing rates effective since April 1, 2021.		
	(2) The carryover balances will differ from the 3% adjustment amounts due to the revenue related expense gross up partially offset by additional interest on the outstanding balance during the amortization period.		

Schedule 175E – Natural Gas 3% Rate Increase Test

The Natural Gas Incremental Surcharge Test is shown in Table 1-18. The test limits the Residential and the Non-Residential Surcharge each to 3%. For both the Residential and the Non-Residential Groups, the incremental surcharge is below 3% (Line 7), so there is no Carryover Deferred Revenue amount (Line 8) to be to be deferred to the following year.

Table 1-22. 2020 Natural Gas 3% Rate Increase Limitation.

Line No.	**3% Incremental Surcharge Test**	Residential	Non-Residential
1	Revenue From 2020 Normalized Loads and Customers at Present Billing Rates (Note 1)	$ 123,149,739	$ 34,857,536
2	August 2021 - July 2022 Usage	135,825,505	60,870,053
3	Proposed Decoupling Recovery Rates	$0.00925	$0.00813
4	Present Decoupling Surcharge Recovery Rates (2)	$0.00000	$0.00419
5	Incremental Decoupling Recovery Rates	$0.00925	$0.00394
6	Incremental Decoupling Recovery	$ 1,256,386	$ 239,828
7	Incremental Surcharge %	**1.02%**	**0.69%**
8	3% Test Adjustment (3)	$ -	$ -
9	3% Test Rate Adjustment	$0.00000	$0.00000
10	Adjusted Proposed Decoupling Recovery Rates	$0.00925	$0.00813
11	Adjusted Incremental Decoupling Recovery	$ 1,256,386	$ 239,828
12	Adjusted Incremental Surcharge %	**1.02%**	**0.69%**

Notes

(1) Revenue from 2020 normalized loads and customers at present billing rates effective since April 1, 2021.

(2) As stated on tariff Sheet 175E, the reversal of a rebate rate is not included in the 3% incremental surcharge test. Therefore the Residential Group rebate of -$0.00685 is $0.00000 in this incremental rate calculation.

(3) The carryover balances will differ from the 3% adjustment amounts due to the revenue related expense gross up partially offset by additional interest on the outstanding balance during the amortization period.

2021 Decoupling Mechanism - Electric (Schedule 75) and Natural Gas (Schedule 175)

In this section, as specified in Schedule 75 and Schedule 175, calculations were carried out separately and in parallel for Residential and Non-Residential accounts. For each of these groups of accounts, the sum of monthly deferral amounts over calendar year 2021 is the cumulative deferral (rebate or surcharge).

Electric Group 1 (Residential) and Group 2 (Non-Residential)

Schedule 75A is used to develop the *Decoupled Revenue per Customer*. Schedule 75B uses the results from Schedule 75A to develop the *Monthly Decoupling Deferral*. There are seven calculation steps in Schedule 75A and there are eight calculation steps in Schedule 75B. These are developed in this subsection of the report. Results for Schedule 75A for both Electric Residential and Electric Non-Residential customers are shown in Tables 1-23 through 1-25. Results for Schedule 75B are shown separately for Electric Residential customers in Table 1-26 and for Electric Non-Residential customers in Table 1-27.[37]

Electric Residential Decoupled Revenue per Customer (Schedule 75A)

Calculation of Decoupled Revenue per Customer for Electric Residential and Electric Non-Residential is specified in seven steps in Schedule 75A. These steps are implemented in Tables 1-23, 1-24 and 1-25.

Step 1: Determine the Total Normalized Revenue.

Total Normalized Revenue is equal to the final approved base rate revenue approved in the Company's last general rate case, individually for each Rate Schedule. Table 1-23, Line 1 shows initial Total Normalized Net Revenue. In Line 2 the Allowed Revenue Increase is shown. The sum of Line 1 and Line 2 is the Allowed Base Rate Revenue or Total Normalized Revenue. Note that the results for Line 1 are used, going forward, only for the individual decoupled schedules. Values in the Total column for Lines 1-6 are not used since they include results for non-decoupled schedules.

Step 2: Determine the Variable Power Supply Revenue.

This value is shown on Line 6 and is the product of Normalized kWh on Line 4 and Retail Revenue Credit from Line 5. Values in the Total column for Lines 1-6 are not used since they include results for non-decoupled schedules.

[37] Tables in this subsection are attachments or parts of attachments to the Electric Decoupling Rate Adjustment filing of May 27, 2022.

Table 1-23: 2021 Development of Electric Decoupled Revenue per Customer.

Electric Decoupling Mechanism
Development of Decoupled Revenue by Rate Schedule - Electric
Washington Docket No. UE-190334 Compliance Filing

		TOTAL	RESIDENTIAL SCHEDULE 1,2	GENERAL SVC. SCH. 11,12	LG. GEN. SVC. SCH. 21,22	PUMPING SCH. 30, 31, 32	EX LG GEN SVC SCHEDULE 25	ST & AREA LTG SCH. 41-48
1	Total Normalized 12ME Dec 2018 Revenue	$ 502,020,000	$ 216,075,000	$ 75,061,000	$ 125,677,000	$ 12,039,000	$ 66,744,000	$ 6,424,000
2	Allowed Revenue Increase (Attachment 1)	$ 28,500,000	$ 14,579,000	$ 2,131,000	$ 7,135,000	$ 684,000	$ 3,789,000	$ 182,000
3	Allowed Base Rate Revenue	$ 530,520,000	$ 230,654,000	$ 77,192,000	$ 132,812,000	$ 12,723,000	$ 70,533,000	$ 6,606,000
4	Normalized kWhs (12ME Dec 2018 Test Year)	5,637,842,826	2,374,703,689	619,305,952	1,365,904,624	145,822,517	1,113,564,012	18,542,032
5	Retail Revenue Adjustment (line 14)	$ 0.01895	$ 0.01895	$ 0.01895	$ 0.01895	$ 0.01895	$ 0.01895	$ 0.01895
6	Variable Power Supply Revenue (L4 * L5)	$ 106,837,122	$ 45,000,635	$ 11,735,848	$ 25,883,893	$ 2,763,337	$ 21,102,038	$ 351,372
7	Delivery & Power Plant Revenue (L3 - L6)	$ 367,997,288	$ 185,653,365	$ 65,456,152	$ 106,928,107	$ 9,959,663		
8	Customer Bills (12ME Dec 2018 Test Year)	3,027,008	2,587,975	386,800	22,787	29,446		
9	Allowed Basic Charges		$ 9.00	$ 20.00	$ 550.00	$ 20.00		
10	Basic Charge Revenue (Ln 8 * Ln 9)	$ 44,149,545	$ 23,291,775	$ 7,736,000	$ 12,532,850	$ 588,920		
11	Decoupled Revenue	$ 323,847,743	$ 162,361,590	$ 57,720,152	$ 94,395,257	$ 9,370,743	Excluded From Decoupling	
12	Retail Revenue Adjustment - (UE-170485 ERM Base	$0.01811						
13	Gross Up Factor for Revenue Related Exp	104.64%						
14	Grossed Up Retail Revenue Adjustment	$0.01895						

		Residential	Non-Residential Group
15	Average Number of Customers (Line 8 / 12)	215,665	36,586
16	Annual kWh	2,374,703,689	2,131,033,093
17	Basic Charge Revenues	23,291,775	20,857,770
18	Customer Bills	2,587,975	439,033
19	Average Basic Charge	$9.00	$47.51

Step 3: Determine Delivery and Power Plant Revenue.

For the decoupled schedules *only*, subtract Variable Power Supply Revenue (Line 6) from the Total Normalized Revenue (Line 3) and enter results on Line 7. Beginning with Line 7, values in the Total column are valid for decoupling.

Step 4: Remove Basic Charge Revenue.

Because the decoupling mechanism only tracks revenue that varies with customer energy usage, revenue directly recovered from Fixed Charges is removed in this step. Basic Charge Revenue is shown on Line 10. It is the product of the number of Customer Bills (2018 Test Year) on Line 8 times the Allowed Basic Charge (Line 9).[38]

Step 5: Determine Decoupled Revenue.

Decoupled Revenue is equal to the Delivery and Power Plant Revenue (Step 3; Line 7) minus the Basic Charge Revenue (Step 4; Line 10). Decoupled Revenue is shown on Line 11.

[38] Basic charge includes minimum charge revenue for non-residential customers.

Step 6: Determine Decoupled Revenue per Customer.

In this step, Decoupled Revenue from Line 11 is put on a per customer basis. The Decoupled Revenue is divided by the approved Rate Year number of customers (by Rate Group). This determines the annual Allowed Decoupled Revenue per Customer.

Table 1-24: 2021 Electric Decoupled Revenue per Customer.

Avista Utilities
Electric Decoupling Mechanism
Development of Annual Decoupled Revenue Per Customer - Electric
Washington Docket No. UE-190334 Compliance Filing

Line No.		Source		Residential		Non-Residential Schedules*
	(a)	(b)		(c)		(d)
1	Decoupled Revenues	Attachment 4, Page 1	$	162,361,590	$	161,486,153
2	Test Year # of Customers 12 ME 12.2018	Revenue Data		215,665		36,586
3	Decoupled Revenue per Customer	(1) / (2)	$	752.84	$	4,413.88
	* Schedules 11, 12, 21, 22, 31, 32.					
	Attachment 4, Page 2					
	Revenues					
	From revenue per customer		$	162,361,239	$	161,486,214
	From basic charge		$	23,291,775	$	20,857,770
	From power supply		$	45,000,635	$	40,383,077
	Total		$	230,653,649	$	222,727,061

Step 7: Determine the Monthly Decoupled Revenue per Customer.

Step 7 converts the annual Allowed Decoupled Revenue per Customer (by Rate Group) into monthly values. The assignment of monthly values is carried out by modeling monthly kWh use (by Rate Group) in relationship to the annual kWh use for the rate year. This modeling is shown in Table 1-21. Kilowatt hours (kWh) for Group 1 (Residential) for 2020 are shown in Line 3 and for Group 2 (Non-Residential) in Line 6. Both monthly values and the annual kWh value are shown. Below the monthly values (Lines 4 and 7) monthly percentages are shown. Lines 11 and 14 show the use of these percentages, applied to annual Allowed Decoupled Revenue per Customer (by Rate Group) to generate monthly values. Table 1-215shows the monthly results for both Electric Residential and Electric Non-Residential decoupling.

The monthly values developed following the steps in Schedule 75A are then used in the implementation of Schedule 75B.

Table 1-25: 2021 Development of Monthly Electric Decoupled Revenue per Customer.

Avista Utilities
Electric Decoupling Mechanism
Development of Monthly Decoupled Revenue Per Customer - Electric
Washington Docket No. UE-190334 Compliance Filing

	Source	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	TOTAL
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
Electric Sales														
Residential														
- Weather-Normalized kWh Sales	Monthly Test Year	292,945,712	209,125,084	229,152,606	174,130,864	159,047,393	151,500,182	166,667,943	194,633,617	145,837,334	161,623,305	216,281,572	273,758,077	2,374,703,689
- % of Annual Total	% of Total	12.34%	8.81%	9.65%	7.33%	6.70%	6.38%	7.02%	8.20%	6.14%	6.81%	9.11%	11.53%	100.00%
*Non-Residential**														
- Weather-Normalized kWh Sales	Monthly Test Year	176,964,441	175,619,317	167,056,292	162,007,860	174,616,873	181,537,287	199,722,134	191,613,197	170,241,283	183,287,817	175,272,145	173,094,449	2,131,033,094
- % of Annual Total	% of Total	8.30%	8.24%	7.84%	7.60%	8.19%	8.52%	9.37%	8.99%	7.99%	8.60%	8.22%	8.12%	100.00%
Monthly Decoupled Revenue Per Customer ("RPC")														
Residential														
-UE-170485 Decoupled RPC	Attachment 4, P. 2 L. 3													$ 752.84
- Monthly Decoupled RPC	(4) x (10)	$ 92.87	$ 66.30	$ 72.65	$ 55.20	$ 50.42	$ 48.03	$ 52.84	$ 61.70	$ 46.23	$ 51.24	$ 68.57	$ 86.79	$ 752.84
*Non-Residential**														
-UE-170485 Decoupled RPC	Attachment 4, P. 2 L. 3													$ 4,413.88
- Monthly Decoupled RPC	(7) x (13)	$ 366.54	$ 363.75	$ 346.01	$ 335.56	$ 361.67	$ 376.01	$ 413.67	$ 396.88	$ 352.61	$ 379.63	$ 363.03	$ 358.52	$ 4,413.88

* Schedules 11, 12, 21, 22, 31, 32.

Schedule 75B – Electric Monthly Decoupling Deferral

Schedule 75B specifies the method for developing the *Monthly Decoupling Deferral* for electric service. The calculation of the monthly electric decoupling deferral for 2021 is shown in Table 1-26 for Electric Residential and in Table 1-27 for Electric Non-Residential. The monthly decoupling deferral amounts across 2021 sum to the annual total decoupling deferral for 2021. The result of these calculations is that for the electric residential group, deferred revenue for 2021 is a refund to customers of $5,123,505,[39] and for the electric non-residential group a surcharge of $2,389,111.[40] However, for the electric residential group, adjustments result in a final customer rebate of $5,801,102.[41] For the electric non-residential group, adjustments result in a final Customer Surcharge Revenue of $2,747,724.[42]

Schedule 75B calculation for Electric Residential follows. There are eight steps. The sequence of the line numbers in Table 1-22 are keyed to the eight steps. Steps 1 through 5 are required to remove new customers (new hookups) from the calculation.

Electric – Residential (Schedule 75B)

Step 1: Deduct new hookup customers. New hookup customers (Line 5) are deducted from total actual number of customers (Line 1) to determine the actual number of test year existing customers each month. The result (actual number of decoupled customers after subtracting out new customers) is shown on Line 5.

Step 2: Calculate total Allowed Decoupled Revenue each month. This is calculated by multiplying the number of Actual Customers after removing new customers (Line 5) by the Monthly Decoupled Revenue per Customer (Line 10). The result is shown on Line 11, Decoupled Revenue.

Step 3: Deduct actual new hookup customer revenue from total actual revenue. This determines the actual test year existing customer revenue collected in the applicable month. To form this result, Actual Base Rate Revenue (Line 12) is adjusted by subtracting New Customer Base Rate Revenue (Line 7). The result is shown in Line 8.

[39] Table 1-26, Line 24, Cumulative Deferral (Rebate)/Surcharge Balance.
[40] Table 1-27, Line 48, Cumulative Deferral (Rebate)/Surcharge) Balance.
[41] Letter, re: Tariff WN U-28, Electric Service Electric Decoupling Rate Adjustment from Joe Miller, Avista Senior Manager for Rates and Tariffs, Regulatory Affairs to Amanda Maxwell, Executive Director and Secretary, Washington Utilities and Transportation Commission dated May 27, 2022, P. 2 of 5.
[42] Letter, re: Tariff WN U-28, Electric Service Electric Decoupling Rate Adjustment from Joe Miller, Avista Senior Manager for Rates and Tariffs, Regulatory Affairs to Amanda Maxwell, Executive Director and Secretary, Washington Utilities and Transportation Commission dated May 27, 2022, P. 3 of 5

Step 4: Deduct actual new hookup customer fixed charge revenue from total actual fixed charge revenue. Line 8, New Customer Basic Charge Revenue, is subtracted from Line 4, Actual Basic Charge Revenue. The result, Actual Basic Charge Revenue/Test Year Existing, is shown on Line 13.

Step 5: Deduct actual new hookup customer kWh sales from total actual kWh sales. This is Line 2 (Actual Usage kWh) minus Line 6 (New Customer Usage (kWh). The result is the Actual Usage (kWh)/Test Year Existing (Line 14) from which new customer (new hookups) actual usage has been removed. Then, Actual Usage (kWh)/Test Year Existing in Line 14 is multiplied by the approved Retail Revenue Credit (Line 15). The result is the revenue collected related to the variable power supply (Variable Power Supply Payments; Line 16). When Step 5 is completed, all quantities remaining in the analysis have been adjusted to remove new customers (new hookups).

Step 6: Compute Customer Decoupled Payments. Actual Decoupled Revenue is calculated by subtracting the Actual Basic Charge Revenue/Test Year Existing (Line 13 and the Variable Power Supply Payments (Line 16) from the Actual Base Rate Revenue/Test Year Existing (Line 12). Customer Decoupled Payments is shown in Line 17.

Step 7: Compute Balance to be Deferred by the Company as a Surcharge or as a Rebate. The Balance (for each month) is computed by subtracting Customer Decoupled Payments (Line 17) from Decoupled Revenue (Line 11). The result (Deferral – Surcharge/Rebate) is shown on Line 19.

This amount is then adjusted for Revenue Related Expenses (Line 20) and for interest at the FERC rate (FERC interest rate at Line 21 and interest at Line 22). The result is the Monthly Electric -Residential Deferral Totals (Line 23).

These monthly amounts are then cumulated in Line 24 to compute the Cumulative Deferral (Rebate)/Surcharge Balance for the Electric Residential Group. The Cumulative Deferral (Rebate)/Surcharge Balance for Electric-Residential is a rebate to customers of $5,123,505.[43] As noted earlier, adjustments included in the letter filing the rate resulted in a final value of $5,801,102.[44]

[43] Table 1-22, line 24, Cumulative Deferral (Rebate)/Surcharge) Balance, last column.
[44] See footnote 31.

Step 8: Comparison. At the end of every 12-month deferral period, the annual decoupled revenue per customer, by rate group, is multiplied by the average annual number of actual test year existing customers. The result of that calculation is compared to the actual deferred revenue for the same 12-month period. The difference between the actual deferred revenue, and the calculated value, is then added to, or subtracted from, the total deferred balance by Rate Group. This calculation is shown in Table 1-28.

Table 1-26: 2021 Electric Decoupling - Residential.

Avista Utilities

Decoupling Mechanism

UE-190334 Base effective 4/1/2020 & UE-200900 Base Effective 10/1/2021

Development of WA Electric Deferrals (Calendar Year 2021)

Line No.		Source	Revised Jan-21	Revised Feb-21	Revised Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Total
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
	Residential Group														
1	Actual Customers	Revenue System	223,405	223,405	223,405	224,063	223,629	223,770	223,958	224,348	224,617	224,905	224,968	225,556	
2	Actual Usage (kWhs)	Revenue System	252,707,036	243,176,802	230,221,468	175,211,847	165,160,581	195,418,248	252,257,937	213,300,859	155,388,557	169,159,242	211,413,739	279,622,692	
3	Actual Base Rate Revenue	Revenue System	$ 24,708,907	$ 23,717,932	$ 22,449,787	$ 16,836,457	$ 16,000,581	$ 18,670,121	$ 24,243,886	$ 21,043,709	$ 15,128,317	$ 17,003,721	$ 21,339,119	$ 28,454,380	
4	Actual Basic Charge Revenue	Revenue System	$ 1,910,628	$ 1,922,490	$ 2,292,716	$ 2,050,768	$ 2,051,037	$ 2,069,712	$ 2,064,231	$ 2,077,094	$ 2,063,601	$ 2,065,050	$ 2,064,460	$ 2,066,931	
5	New Customers	Revenue System	5,722	5,532	6,496	6,344	6,547	6,971	7,080	7,337	7,567	5,338	5,530	5,942	
6	New Customer Usage (kWhs)	Revenue System	5,453,471	5,273,613	5,258,143	3,904,551	3,133,924	3,338,318	4,816,736	4,770,441	3,912,316	2,285,907	3,300,094	5,140,312	
7	New Customer Base Rate Revenue	Revenue System	$ 539,229	$ 521,280	$ 522,512	$ 389,461	$ 319,982	$ 340,620	$ 475,648	$ 471,102	$ 394,480	$ 242,626	$ 346,305	$ 532,153	
8	New Customer Basic Charge Revenue	Revenue System	$ 51,707	$ 49,923	$ 58,349	$ 57,206	$ 58,889	$ 62,748	$ 63,749	$ 65,997	$ 68,031	$ 48,006	$ 49,788	$ 53,325	
9	Actual Customers/Test Year Existing	(1) - (5)	217,683	217,873	216,909	217,719	217,082	216,799	216,878	217,011	217,050	219,567	219,438	219,614	2,613,623
10	Monthly Decoupled Revenue per Customer	Attachment 3, Page 3	$92.87	$66.30	$72.65	$55.20	$50.42	$48.03	$52.84	$61.70	$46.23	$61.82	$78.34	$100.31	$787.18
11	Decoupled Revenue	(9) x (10)	$ 20,216,451	$ 14,444,510	$ 15,757,802	$ 12,018,917	$ 10,945,702	$ 10,412,708	$ 11,459,372	$ 13,390,379	$ 10,035,101	$ 13,574,134	$ 17,190,676	$ 22,003,863 *	$ 171,449,615
12	Actual Base Rate Revenue/Test Year Existing	(3) - (7)	$ 24,169,678	$ 23,196,653	$ 21,927,275	$ 16,446,996	$ 15,680,599	$ 18,329,501	$ 23,768,239	$ 20,572,607	$ 14,733,836	$ 16,761,095	$ 20,992,813	$ 27,922,227	$ 244,501,520
13	Actual Basic Charge Revenue/Test Year Existing	(4) - (8)	$ 1,858,921	$ 1,872,567	$ 2,234,367	$ 1,993,562	$ 1,992,148	$ 2,006,964	$ 2,000,482	$ 2,011,097	$ 1,995,570	$ 2,017,044	$ 2,014,672	$ 2,013,606	$ 24,011,000
14	Actual Usage (kWhs)/Test Year Existing	(2) - (6)	247,253,565	237,903,189	224,963,326	171,307,296	162,026,657	192,079,931	247,441,200	208,530,417	151,476,241	166,873,335	208,113,644	274,482,380	2,492,451,183
15	Retail Revenue Credit ($/kWh)	Attachment 3, Page 1	$ 0.01895	$ 0.01895	$ 0.01895	$ 0.01895	$ 0.01895	$ 0.01895	$ 0.01895	$ 0.01895	$ 0.01895	$ 0.01360	$ 0.01360	$ 0.01360	
16	Variable Power Supply Payments	(14) x (15)	$ 4,685,455	$ 4,508,265	$ 4,263,055	$ 3,246,273	$ 3,070,405	$ 3,639,915	$ 4,689,011	$ 3,951,651	$ 2,870,475	$ 2,269,477	$ 2,830,346	$ 3,732,960	$ 43,757,289
17	Customer Decoupled Payments	(12) - (13) -(16)	$ 17,625,302	$ 16,815,820	$ 15,429,853	$ 11,207,161	$ 10,618,046	$ 12,682,622	$ 17,078,746	$ 14,609,859	$ 9,867,792	$ 12,474,574	$ 16,147,796	$ 22,175,661	$ 176,733,232
18	Residential Revenue Per Customer Received	(17) / (9)	$80.97	$77.18	$71.14	$51.48	$48.91	$58.50	$78.75	$67.32	$45.46	$56.81	$73.59	$100.98	$811.44
19	Deferral - Surcharge (Rebate)	(11) - (17)	$ 2,591,149	$ (2,371,311)	$ 327,949	$ 811,756	$ 327,656	$ (2,269,914)	$ (5,619,374)	$ (1,219,480)	$ 167,310	$ 1,099,560	$ 1,042,880	$ (171,797)	$ (5,283,617)
20	Deferral - Revenue Related Expenses	Rev Conv Factor	$ (114,967)	$ 105,213	$ (14,551)	$ (36,017)	$ (14,538)	$ 100,714	$ 249,326	$ 54,107	$ (7,423)	$ (48,305)	$ (45,815)	$ 7,547	$ 235,291
21		FERC Rate	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	
22	Interest on Deferral	Avg Balance Calc	$ 3,353	$ 3,647	$ 1,012	$ 2,490	$ 3,971	$ 1,468	$ (8,737)	$ (17,611)	$ (19,020)	$ (17,431)	$ (14,705)	$ (13,617)	$ (75,179)
23	**Monthly Residential Deferral Totals**		**$ 2,479,536**	**$ (2,262,451)**	**$ 314,410**	**$ 778,229**	**$ 317,089**	**$ (2,167,732)**	**$ (5,378,785)**	**$ (1,182,984)**	**$ 140,866**	**$ 1,033,823**	**$ 982,360**	**$ (177,867)**	**$ (5,123,505)**
24	Cumulative Deferral (Rebate)/Surcharge Balance	Σ((19) ,(20) , (22))	$ 2,479,536	$ 217,084	$ 531,495	$ 1,309,724	$ 1,626,813	$ (540,918)	$ (5,919,703)	$ (7,102,687)	$ (6,961,820)	$ (5,927,997)	$ (4,945,638)	$\boxed{\textbf{\$ (5,123,505)}}$	

*** - As approved in Docket No. UE-190334, the Company is required to calculate decoupled revenue using YTD average customers, compare to what was recorded using monthly customer counts, and record the difference in December so that the annual decoupled revenue is based on YTD average customers. This amount includes that annual true-up that resulted in a decrease to decoupled revenue of $24,965.05.**

Electric – Non-Residential (Schedule 75B)

The Schedule 75B calculation for Electric Non-Residential steps follow. There are eight steps. The sequence of the line numbers in Table 1-23 are keyed to the eight steps. Steps 1 through 5 are required to remove new customers (new hookups) from the calculation.

Step1: Deduct new hookup customers. New hookup customers (Line 29) are deducted from the total actual number of customers (Line 25) to determine the actual number of test year existing customers each month. The result (actual number of customers after subtracting out new customers) is in Line 33.

Step 2: Calculate total Allowed Decoupled Revenue each month. This is calculated by multiplying the number of Actual Customers after removing new customers (Line 33) by the Monthly Decoupled Revenue per Customer (Line 34). The result is shown on Line 35.

Step 3: Deduct actual new hookup customer revenue from total actual revenue. This determines the actual test year existing customer revenue collected in the applicable month. To form this result, Actual Base Rate Revenue (Line 27) is adjusted by subtracting New Customer Base Rate Revenue (Line 31). The result is shown on Line 36.

Step 4: Deduct actual new hookup customer fixed charge revenue from total actual fixed charge revenue. Line 32, New Customer Basic Charge Revenue, is subtracted from Line 28, Actual Basic Charge Revenue. The result, Actual Basic Charge Revenue (Test Year Existing), is shown on Line 37.

Step 5: Deduct actual new hookup customer kWh sales from total actual kWh sales. This is Line 26 (Total Actual kWh Sales) minus Line 30 (New Customer Usage (kWh). The result is the Actual Usage (kWh) from which new customer actual usage has been removed. The result is shown in Line 38. Then, Actual Usage (kWh) in Line 38 is multiplied by the approved Retail Revenue Credit (Line 39). The result is the revenue collected related to the variable power supply (Variable Power Supply Payments in Line 40). When Step 5 is completed, all remaining quantities have been adjusted to remove new customers (new hookups).

Step 6: Compute Customer Decoupled Payments. Actual Decoupled Revenue is calculated by subtracting the Actual Basic Charge Revenue (Test Year Existing) in Line

37 and the Variable Power Supply Payments (Line 40) from the Actual Base Rate Revenue (Line 36) and is shown on Line 41.

Step 7: Compute Balance to be Deferred by the Company as a Surcharge or as a Rebate. The Balance (for each month) is computed by subtracting Customer Decoupled Payments (Line 41) from Decoupled Revenue (Line 35). The result (Deferral – Surcharge/Rebate) is shown on Line 43. This amount is then adjusted for Revenue Related Expenses (Line 44) and for interest at the FERC rate (Lines 45 and 46). The result is the Monthly Non-Residential Deferral Total (Line 47). These monthly amounts are cumulated in Line 48.

Monthly Non-Residential Deferral Total for each month is shown just below Line 12. This is the difference between the Actual Decoupled Revenue (Step 6; Line 9) and the Allowed Decoupled Revenue (Step 2; Line 3) plus any interest on the deferral. The Total Cumulative Deferral (Rebate)/Surcharge Balance is tracked in Line 48. The total cumulative deferral for Electric Non-Residential is a surcharge to customers of $2,389,111.[45] This result is subject to adjustment.

Step 8: Comparison. At the end of every 12-month deferral period, the annual decoupled revenue per customer, by rate group, will be multiplied by the average annual number of actual test year existing customers. The results of that calculation will be compared to the actual deferred revenue for the same 12-month period. The difference between the actual deferred revenue and the calculated value will be added to, or subtracted from, the total deferred balance by Rate Group. This calculation is shown in Table 1-8, and results in a decrease of $24,965.05 for Residential; and an increase of $406.83 for Non-Residential.[46]

[45] Table 1-23, line 48, Total Cumulative Deferral (Rebate)/Surcharge) Balance, last column.
[46] Table 1-8, Net increase/(decrease) to Decoupled Revenue due to Average Calculation (middle of Table for Residential, bottom line for Non-Residential).

Table 1-27: 2021 Electric Decoupling - Non-Residential.

Avista Utilities
Decoupling Mechanism
UE-190334 Base effective 4/1/2020 & UE-200900 Base Effective 10/1/2021
Development of WA Electric Deferrals (Calendar Year 2021)

Line No.		Source	Revised Jan-21	Revised Feb-21	Revised Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Total
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
	Non-Residential Group														
25	Actual Customers	Revenue System	37,888	37,888	37,888	38,020	37,820	38,221	38,142	38,125	38,161	38,317	38,098	38,370	
26	Actual Usage (kWhs)	Revenue System	166,909,354	157,727,108	168,214,115	155,684,619	177,821,928	208,606,878	203,985,723	197,901,981	177,337,033	175,624,228	164,220,212	183,526,968	
27	Actual Base Rate Revenue	Revenue System	$ 17,448,084	$ 16,763,031	$ 18,238,873	$ 16,657,934	$ 18,676,991	$ 21,340,727	$ 21,029,491	$ 20,469,420	$ 18,597,954	$ 18,846,990	$ 17,834,276	$ 19,526,738	
28	Actual Basic Charge Revenue	Revenue System	$ 1,673,037	$ 1,627,814	$ 1,944,698	$ 1,770,531	$ 1,719,333	$ 1,749,355	$ 1,734,734	$ 1,712,436	$ 1,715,536	$ 1,717,925	$ 1,702,423	$ 1,700,077	
29	New Customers	Revenue System	1,622	1,562	1,805	1,771	1,932	2,007	2,090	2,187	2,190	1,754	1,809	1,885	
30	New Customer Usage (kWhs)	Revenue System	6,267,128	5,493,508	6,239,854	5,228,133	4,910,750	6,230,698	6,242,989	7,306,694	6,780,553	4,854,698	6,655,678	6,497,568	
31	New Customer Base Rate Revenue	Revenue System	$ 708,442	$ 630,898	$ 710,227	$ 619,053	$ 602,106	$ 718,199	$ 729,397	$ 837,328	$ 788,169	$ 574,823	$ 747,171	$ 742,227	
32	New Customer Basic Charge Revenue	Revenue System	$ 54,938	$ 50,447	$ 57,119	$ 55,943	$ 63,565	$ 63,212	$ 67,756	$ 74,043	$ 71,428	$ 54,963	$ 58,272	$ 56,901	
33	Actual Customers/Test Year Existing	(25) - (29)	36,266	36,326	36,083	36,249	35,888	36,214	36,052	35,938	35,971	36,563	36,289	36,485	434,324
34	Monthly Decoupled Revenue per Customer	Attachment 3, Page 3	$366.54	$363.75	$346.01	$335.56	$361.67	$376.01	$413.67	$396.88	$352.61	$420.52	$365.86	$403.51	$4,502.58
35	Decoupled Revenue	(33) x (34)	$ 13,292,785	$ 13,213,571	$ 12,485,209	$ 12,163,609	$ 12,979,734	$ 13,616,725	$ 14,913,717	$ 14,262,960	$ 12,683,751	$ 15,375,376	$ 13,276,554	$ 14,722,601 **	$ 162,986,590
36	Actual Base Rate Revenue/Test Year Existing	(27) - (31)	$ 16,739,642	$ 16,132,133	$ 17,528,645	$ 16,038,881	$ 18,074,885	$ 20,622,528	$ 20,300,094	$ 19,632,092	$ 17,809,784	$ 18,272,166	$ 17,087,105	$ 18,784,511	$ 217,022,467
37	Actual Basic Charge Revenue/Test Year Existing	(28) - (32)	$ 1,618,099	$ 1,577,367	$ 1,887,579	$ 1,714,587	$ 1,655,768	$ 1,686,143	$ 1,666,978	$ 1,638,392	$ 1,644,108	$ 1,662,962	$ 1,644,151	$ 1,643,176	$ 20,039,310
38	Actual Usage (kWhs)/Test Year Existing	(26) - (30)	160,642,227	152,233,600	161,974,261	150,456,487	172,911,179	202,376,180	197,742,734	190,595,286	170,556,480	170,769,530	157,564,534	177,029,400	2,064,851,898
39	Retail Revenue Credit ($/kWh)	Attachment 3, Page 1	$ 0.01895	$ 0.01895	$ 0.01895	$ 0.01895	$ 0.01895	$ 0.01895	$ 0.01895	$ 0.01895	$ 0.01895	$ 0.01360	$ 0.01360	$ 0.01360	
40	Variable Power Supply Payments	(38) x (39)	$ 3,044,170	$ 2,884,827	$ 3,069,412	$ 2,851,150	$ 3,276,667	$ 3,835,029	$ 3,747,225	$ 3,611,781	$ 3,232,045	$ 2,322,466	$ 2,142,878	$ 2,407,600	$ 36,425,249
41	Customer Decoupled Payments	(36) - (37) -(40)	$ 12,077,373	$ 11,669,939	$ 12,571,654	$ 11,473,143	$ 13,142,450	$ 15,101,356	$ 14,885,892	$ 14,381,919	$ 12,933,631	$ 14,286,739	$ 13,300,076	$ 14,733,735	$ 160,557,908
42	Non-Residential Revenue Per Customer Received	(41) / (33)	$333.02	$321.26	$348.41	$316.51	$366.21	$417.00	$412.90	$400.19	$359.56	$390.74	$366.50	$403.83	$4,436.08
43	Deferral - Surcharge (Rebate)	(35) - (41)	$ 1,215,412	$ 1,543,632	$ (86,446)	$ 690,465	$ (162,716)	$ (1,484,631)	$ 27,825	$ (118,960)	$ (249,880)	$ 1,088,637	$ (23,522)	$ (11,134)	$ 2,428,682
44	Deferral - Revenue Related Expenses	Rev Conv Factor	$ (53,927)	$ (68,489)	$ 3,836	$ (30,635)	$ 7,220	$ 65,872	$ (1,235)	$ 5,278	$ 11,087	$ (47,825)	$ 1,033	$ 489	$ (107,297)
45		FERC Rate	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	
46	Interest on Deferral	Avg Balance Calc	$ 1,573	$ 5,148	$ 7,047	$ 7,848	$ 8,552	$ 6,444	$ 4,576	$ 4,470	$ 4,005	$ 5,102	$ 6,495	$ 6,467	$ 67,726
47	**Monthly Non-Residential Deferral Totals**		**$ 1,163,058**	**$ 1,480,290**	**$ (75,563)**	**$ 667,678**	**$ (146,945)**	**$ (1,412,316)**	**$ 31,166**	**$ (109,211)**	**$ (234,788)**	**$ 1,045,913**	**$ (15,994)**	**$ (4,177)**	**$ 2,389,111**
48	Cumulative Deferral (Rebate)/Surcharge Balance	Σ((43) ,(44) , (46))	$ 1,163,058	$ 2,643,348	$ 2,567,785	$ 3,235,463	$ 3,088,519	$ 1,676,202	$ 1,707,369	$ 1,598,157	$ 1,363,370	$ 2,409,283	$ 2,393,289	**$ 2,389,111**	
49	**Total Cumulative Deferral (Rebate)/Surcharge Balance**		$ 3,642,594	$ 2,860,433	$ 3,099,280	$ 4,545,187	$ 4,715,332	$ 1,135,284	$ (4,212,334)	$ (5,504,529)	$ (5,598,450)	$ (3,518,714)	$ (2,552,349)	**$ (2,734,393)**	

**** - As approved in Docket No. UE-190334, the Company is required to calculate decoupled revenue using YTD average customers, compare to what was recorded using monthly customer counts, and record the difference in December so that the annual decoupled revenue is based on YTD average customers. This amount includes that annual true-up that resulted in an increase to decoupled revenue of $406.83.**

Table 1-28: 2021 Annual True-Up for Electric Residential and Electric Non-Residential.

Purpose: As required by UE-190334 (UE-190222, consolidated) paragraph 111, the Company is required to calculate decoupled revenue using YTD average customers, compare to what was recorded using monthly customer counts, and record the difference so that the annual decoupled revenue is based on YTD average customers.

Procedure: Separately for residential and non-residential, calculated average customers and multiplied that by the sum of decoupled revenue by month to calculate total allowed decoupled revenue for the period based on average customers. Note, the average customer calculation and allowed revenue was broken out into the period of Jan - Sep 2021 when the UE-190334 authorized base was in effect and Oct - Dec 2021 when the UE-200900 authorized base was in effect. This was compared to the amount recorded using monthly actual customers and monthly decoupled revenue per customer. The difference was recorded with the monthly decoupled revenue for December 2021.

Residential			
Average Actual Customers (average of line 9 in Deferral Calc for Jan-Sep 2021 - UE-190334)			217,223
Sum of Decoupled Revenue (sum of line 10 in Deferral Calc for Jan-Sep 2021 - UE-190334)		$	546.25
Total Decoupled Revenue using Average Actual Customers		$	118,657,158.69
Average Actual Customers (average of line 9 in Deferral Calc for Oct-Dec 2021 - UE-200900)			219,540
Sum of Decoupled Revenue (sum of line 10 in Deferral Calc for Oct-Dec 2021 - UE-200900)		$	240.47
Total Decoupled Revenue using Average Actual Customers		$	52,792,456.33
Total Annual Authorized Decoupled Revenue using Average Actual Customers	Σ A	$	171,449,615.02
Less Jan - November Decoupled Revenue (sum of line 11 in Deferral Calc for Jan-Nov 2021)			149,445,751.74
Decoupled Revenue to record for December to reflect true-up		$	22,003,863.28
December Actual Customers (line 9, column n in Deferral Calc)			219,614
December Decoupled Revenue per Customer (line 10, column n in Deferral Calc)		$	100.31
Total Decoupled Revenue for December using monthly actuals		$	22,028,828.33
Net increase/(decrease) to Decoupled Revenue due to Average Calculation		$	(24,965.05)
Non-Residential			
Average Actual Customers (average of line 33 in Deferral Calc for Jan-Sep 2021 - UE-190334)			36,110
Sum of Decoupled Revenue (sum of line 34 in Deferral Calc for Jan-Sep 2021 - UE-190334)		$	3,312.70
Total Decoupled Revenue using Average Actual Customers		$	119,620,361.51
Average Actual Customers (average of line 33 in Deferral Calc for Oct-Dec 2021 - UE-200900)			36,446
Sum of Decoupled Revenue (sum of line 34 in Deferral Calc for Oct-Dec 2021 - UE-200900)		$	1,189.89
Total Decoupled Revenue using Average Actual Customers		$	43,366,228.88
Total Annual Authorized Decoupled Revenue using Average Actual Customers	Σ B	$	162,986,590.39
Less Jan - November Decoupled Revenue (sum of line 35 in Deferral Calc for Jan-Nov 2021)			148,263,989.26
Decoupled Revenue to record for December to reflect true-up		$	14,722,601.13
December Actual Customers (line 33, column n in Deferral Calc)			36,485
December Decoupled Revenue per Customer (line 34, column n in Deferral Calc)		$	403.51
Total Decoupled Revenue for December using monthly actuals		$	14,722,194.30
Net increase/(decrease) to Decoupled Revenue due to Average Calculation		$	406.83

The result of these calculations is that for the gas Residential Group, deferred revenue for 2021 is in the rebate direction with a decoupling Deferred Revenue of ($5,123,505)[47]. Adjustments, conveyed in the annual filing, result in a final Residential rebate of ($5,801,102), including a prior year carryover offset of ($224,670) and other adjustments (Table 1-29).[48]

Table 1-29: 2021 Electric Residential Rate Determination.

Residential Electric Service: Adjustments		
2021 Deferred Revenue	$	(5,123,505)
Add: Earnings Sharing/DSM Adjustment	$	-
Add: Prior Year Carryover Balance	$	(224,670)
Add: Interest through 7/31/2024	$	(187,264)
Add: Revenue Related Expense Adjustment	$	(265,663)
Total Requested Recovery	$	(5,801,102)
Customer Surcharge Revenue	$	(5,801,102)
Carryover Deferred Revenue	$	-

For Non-Electric Residential service, the computations developed deferred revenue of $2,389,111 in the surcharge direction (Table 1-6, Line 48, Cumulative Deferrals (Rebate)/Surcharge Balance, Dec-21 Column, and Table 1-30, 2021 Deferred Revenue). Adjustments (Table 1-30), including a Prior Year Carryover Balance of $148,270 and other adjustments produced a Customer Surcharge Revenue amount of $2,727,724.[49]

Table 1-30: 2021 Electric Non-Residential Group Rate Determination.

Non-Residential Electric Service: Adjustments		
2021 Deferred Revenue	$	2,389,111
Add: Earnings Sharing/DSM Adjustment	$	(17,014)
Add: Prior Year Carryover Balance	$	148,270
Add: Interest through 7/31/2024	$	86,597
Add: Revenue Related Expense Adjustment	$	123,746
Total Requested Recovery	$	2,747,724
Customer Surcharge Revenue	$	2,747,724
Carryover Deferred Revenue	$	-

[47] Table 1-26, Line 24, Cumulative Deferral (Rebate)/Surcharge Balance, Dec-21 Column.
[48] Letter, re: Tariff WN U-29, Natural Gas Service Decoupling Rate Adjustment from Joe Miller, Avista Senior Manager for Rates and Tariffs, Regulatory Affairs to Amanda Maxwell, Executive Director and Secretary, Washington Utilities and Transportation Commission dated May 27, 2022, P. 2 of 5.
[49] Letter of Joe Miller, Senior Manager of Rates and Tariffs, Regulatory Affairs, Avista to Amanda Maxwell, Executive Director and Secretary, Washington Utilities and Transportation Commission, Re: Tariff WN U-28, Electric Service Electric Decoupling Rate Adjustment, May 26, 2022, Page 3 of 6.

Natural Gas Group 1 (Residential) and Group 2 (Non-Residential)

For natural gas, following steps in Schedule 175A, *Decoupled Revenue per Customer (by Rate Group)* is developed.[50] Calculation of Decoupled Revenue per Customer (by Rate Group) is specified in seven steps in Schedule 175A. These steps are implemented in the Residential Customers in Table 1-9 and for the Non-Residential Customers in Table 1-10.[51] Monthly Decoupled Revenue per Customer for Group 1: Residential and Group 2: Non-Residential are then used to develop the *Monthly Decoupling Deferral* for natural gas, following the steps in Schedule 175B.

Natural Gas Decoupling Deferral (Schedule 175A)

Step 1: Determine the Total Normalized Revenue. The Total Normalized Revenue is equal to the final approved base rate revenue approved in the Company's last general rate case, individually for each rate schedule. Table 1-25, Line 1 shows initial Total Normalized Net Revenue. In addition, Line 2 shows Allowed Revenue Decrease. The sum of Line 1 and Line 2 is shown on Line 3 as the Allowed Base Rate Revenue.

Step 2: Determine Variable Gas Supply Revenue. The product of Normalized Therms (Line 4) from the last approved general rate case (2018 Rate Year) and PGA Rates (Line 5) is the Variable Gas Supply Revenue (Line 6).

Step 3: Determine Delivery Revenue. To determine the Delivery Revenue (Line 7), the Variable Gas Supply Revenue (Line 6) is subtracted from the Total Normalized Revenue (Line1).

Step 4: Remove Basic Charge Revenue. Step 4 is to calculate the Basic Charge Revenue. Because the decoupling mechanism only tracks revenue that varies with customer energy usage, revenue from previously allocated Fixed Charges is removed. Basic Charge Revenue is the product of the number of Customer Bills in the test period (2018 Rate Year) on Line 8 times the Settlement Basic Charges (Line 9). The result, Basic Charge Revenue, is shown on Line 10.[52]

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[50] Avista Corporation, dba Avista Utilities, Schedule 175A, Decoupling Mechanism – Natural Gas, Issued June 12, 2015, Effective August 1, 2015.
[51] All tables in this section are attachments or parts of attachments to the Electric and Natural Gas Decoupling Rate Adjustment filings of August 31, 2016.
[52] For natural gas minimum charges are treated like fixed charges.

Step 5: Determine Allowed Decoupled Revenue. The Allowed Decoupled Revenue is equal to the Delivery Revenue (from Line 7) minus the Basic Charge Revenue (Line 10). The resulting Decoupled Revenue is shown on Line 11.

Step 6: Determine the Allowed Decoupled Revenue per Customer. In Step 6, Decoupled Revenue from Line 11 is put on a per customer basis. The Decoupled Revenue (by Rate Group) is divided by the approved Rate Year number of customers (by Rate Group). This determines the annual Allowed Decoupled Revenue per Customer (by Rate Group) as shown in Table 1-26.

Step 7: Determine the Monthly Allowed Decoupled Revenue per Customer. This converts the annual Allowed Decoupled Revenue per Customer (by Rate Group) into monthly values. The assignment of monthly values is carried out by modeling monthly therm use (by Rate Group) in relationship to the annual therm use for the rate year. This modeling is shown in Table 1-27.

In Table 1-27, the therm usage for Group 1 (Residential) for 2018 is shown in Line 4 and for Group 2 (Non-Residential) in Line 8. Both monthly therm values and the annual therm values are shown. Below the monthly values, percentages (Lines 5 and 9) are shown. Lines 14 and 18 show the use of these percentages, applied to annual Allowed Decoupled Revenue per Customer (by Rate Group) to generate monthly values.

These monthly values are then taken forward to be used in the implementation of Schedule 175B.

Table 1-31. 2021 Development of Natural Gas Decoupled Revenue per Customer

Natural Gas Decoupling Mechanism
Development of Decoupled Revenue by Rate Schedule - Natural Gas
Washington Docket No. UG-190355 Compliance Filing

	TOTAL	RESIDENTIAL SCHEDULE 101/102	GENERAL SVC. SCH. 111/112/116	LG. GEN. SVC. SCH. 121/122/126	INTERRUPTIBLE SCH 131	SCHEDULES 132	SCHEDULES 146 & 148
1 Total Normalized 12 ME Dec 2018 Revenue	$ 93,707,000	$ 71,132,000	$ 17,418,000	$ -	$ -	$ 201,000	$ 4,956,000
2 Allowed Revenue Decrease (Attachment 2)	$ 8,000,000	$ 6,187,000	$ 1,515,000	$ -	$ -	$ 17,000	$ 281,000
3 Allowed Base Rate Revenue	$ 101,707,000	$ 77,319,000	$ 18,933,000	$ -	$ -	$ 218,000	$ 5,237,000
4 Normalized Therms (12ME Dec 2018 Test Year)	275,981,665	128,985,980	55,884,877	-	-	985,267	90,125,541
5 Schedule 150 PGA Rates excluded from base rates		$ -	$ -	$ -	$ -		
6 Variable Gas Supply Revenue	$ -	$ -	$ -	$ -	$ -		
7 Delivery Revenue (Ln 3 - Ln 6)	$ 96,252,000	$ 77,319,000	$ 18,933,000	$ -	$ -		
8 Customer Bills (12ME Dec 2018 Test Year)	1,978,935	1,941,495	36,876	0	0	24	540
9 Allowed Basic / Minimum Charges		$9.50	$107.56	$0.00	$0.00		
10 Basic Charge Revenue (Ln 8 * Ln 9)	$ 22,410,585	$ 18,444,203	$ 3,966,383	$ -	$ -		
11 Decoupled Revenue	$ 73,841,415	$ 58,874,798	$ 14,966,617	$ -	$ -	Excluded From Decoupling	
		Residential	Non-Residential Group				
12 Average Number of Customers (Line 8 / 12)		161,791	3,073				
13 Annual Therms		128,985,980	55,884,877				
14 Basic Charge Revenues		$ 18,444,203	$ 3,966,383				
15 Customer Bills		1,941,495	36,876				
16 Average Basic Charge		$9.50	$107.56				

Table 1-32. 2021 Natural Gas Decoupled Revenue per Customer

Avista Utilities
Natural Gas Decoupling Mechanism
Development of Decoupled Revenue Per Customer - Natural Gas
Washington Docket No. UG-200901 Compliance Filing

Line No.		**Source**	**Residential Schedules***	**Non-Residential Schedules****
	(a)	(b)	(c)	(d)
1	Decoupled Revenues	Attachment 4, Page 1	$ 67,962,780	$ 16,088,382
2	Test Year # of Customers 12 ME12.2018	Revenue Data	165,362	3,105
3	Decoupled Revenue Per Customer	(1) / (3)	$ 410.99	$ 5,182.28
	*Rate Schedules 101, 102. **Rate Schedules 111, 112, 116, 131.			
Attachment 4, Page 2				
		Revenues		
		From Revenue Per Customer	$ 67,961,957	$ 16,088,388
		From Basic Charges	$ 18,851,221	$ 4,449,618
		From Gas Supply	$ -	$ -
		Total	$ 86,813,178	$ 20,538,006

Table 1-33. 2021 Development of Monthly Natural Gas Decoupled Revenue per Customer

Avista Utilities
Natural Gas Decoupling Mechanism
'Development of Monthly Decoupled Revenue Per Customer - Natural Gas
Washington Docket No. UG-200901 Compliance Filing

Line No.		Source	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	TOTAL
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
1															
2	**Natural Gas Delivery Volume**														
3	*Residential**														
4	- Weather-Normalized Therm Delivery Volume	Monthly Rate Year	22,053,451	17,838,631	15,392,331	9,335,434	6,176,185	3,137,238	2,719,096	2,706,113	2,771,534	10,154,966	17,140,392	22,670,233	132,095,604
5	- % of Annual Total	% of Total	16.70%	13.50%	11.65%	7.07%	4.68%	2.37%	2.06%	2.05%	2.10%	7.69%	12.98%	17.16%	100.00%
6															
7	*Non-Residential***														
8	- Weather-Normalized Therm Delivery Volume	Monthly Rate Year	8,577,346	7,573,569	6,130,350	4,993,382	3,224,280	2,598,074	2,115,989	2,178,138	2,697,188	4,650,252	6,926,057	8,661,298	60,325,922
9	- % of Annual Total	% of Total	14.22%	12.55%	10.16%	8.28%	5.34%	4.31%	3.51%	3.61%	4.47%	7.71%	11.48%	14.36%	100.00%
10															
11	**Monthly Decoupled Revenue Per Customer ("RPC")**														
12	*Residential**														
13	-UG-190335Decoupled RPC	Attachment 5, P. 2 L. 3													$ 410.99
14	-Monthly Decoupled RPC	() x (13)	$ 68.62	$ 55.50	$ 47.89	$ 29.05	$ 19.22	$ 9.76	$ 8.46	$ 8.42	$ 8.62	$ 31.60	$ 53.33	$ 70.53	$ 410.99
15															
16	*Non-Residential***														
17	-UG-190335 Decoupled RPC	Attachment 5, P. 2 L. 3													$ 5,182.28
18	-Monthly Decoupled RPC	() x (17)	$ 736.83	$ 650.61	$ 526.63	$ 428.95	$ 276.98	$ 223.19	$ 181.77	$ 187.11	$ 231.70	$ 399.48	$ 594.98	$ 744.05	$ 5,182.28
19															
20	*Rate Schedules 101, 102.														
21	**Rate Schedules 111, 112, 116, 131.														

Natural Gas Monthly Decoupling Deferral

Schedule 175B specifies the method for developing the *Monthly Decoupling Deferral* for natural gas service. The calculation of the monthly natural gas decoupling deferral for 2021 is shown in Table 1-28 for Gas Residential and in Table 1-29 for Gas Non-Residential. The monthly decoupling deferral amounts across 2021 sum to the annual total decoupling deferral for 2021.

The Schedule 175B calculation steps for Natural Gas Residential follow. There are eight steps. The sequence of the line numbers in Table 1-14 are keyed to the eight steps. Steps 1 through 5 are required to remove new customers (new hookups) from the calculation.

Natural Gas – Residential (Schedule 175B)

Step 1: Deduct new hookup customers. New hookup customers (Line 5) are deducted from total actual number of customers (Line 1) to determine the actual number of test year existing customers each month. The result (actual number of decoupled customers after subtracting out new customers) is shown on Line 9.

Step 2: Calculate total Allowed Decoupled Revenue each month. This is calculated by multiplying the number of Actual Customers after removing new customers (Line 9) by the Monthly Decoupled Revenue per Customer (Line 10). The result is shown on Line 11, Decoupled Revenue.

Step 3: Deduct actual new hookup customer revenue from total actual revenue. This determines the actual test year existing customer revenue collected in the applicable month. To form this result, Actual Base Rate Revenue (Line 3) is adjusted by subtracting New Customer Base Rate Revenue (Line 7). The result is shown on Line 12.

Step 4: Deduct actual new hookup customer fixed charge revenue from total actual fixed charge revenue. Line 8, New Customer Basic Charge Revenue, is subtracted from Line 4, Actual Basic Charge Revenue. The result, Actual Basic Charge Revenue (Test Year Existing), is shown on Line 13.

Step 5: Deduct actual new hookup customer kWh sales from total actual kWh sales. This is Line 2 (Actual Usage kWh) minus Line 6 (New Customer Usage (kWh). The result is the Actual Usage (kWh)/Test Year Existing (Line 14) from which new customer (new hookups) actual usage has been removed. Then, Actual Usage (kWh)/Test Year Existing in Line 14 is multiplied by the approved Retail Revenue Credit (Line 15). The result is the revenue collected related to the variable power supply (Variable Power

Supply Payments; Line 16). When Step 5 is completed, all quantities remaining in the analysis have been adjusted to remove new customers (new hookups).

Step 6: Compute Customer Decoupled Payments. Actual Decoupled Revenue is calculated by subtracting the Actual Basic Charge Revenue/Test Year Existing in Line 13 and the Variable Power Supply Payments (Line 16) from the Actual Base Rate Revenue/Test Year Existing (Line 12). Customer Decoupled Payments is shown on Line 17.

Step 7: Compute Balance to be Deferred by the Company as a Surcharge or as a Rebate. The Balance (for each month) is computed by subtracting Customer Decoupled Payments (Line 17) from Decoupled Revenue (Line 11).[53] The result (Deferral – Surcharge/Rebate) is shown on Line 19.

This amount is then adjusted for Revenue Related Expenses (Line 20) and for interest at the FERC rate (FERC interest rate at Line 21 and interest at Line 22). The result is the Monthly Electric Residential Deferral Total (Line 23).

These monthly amounts are then cumulated in Line 24. The Total Cumulative Deferral (Rebate)/Surcharge Balance is tracked in Line 48. The total cumulative deferral for Natural Gas Residential is a decoupling refund to customers of $.[54] However, this is modified by adjustments in the filing for Tariff U-29, Natural Gas Service Natural Gas Decoupling Rate Adjustment, dated May 27, 2022.[55] In the filing, the Proposed Decoupling Revenue is set to $5,378,553, and there is a Carryover Deferred Revenue of $1,642,757.

Step 8: Comparison. At the end of every 12-month deferral period, the annual decoupled revenue per customer, by rate group, is multiplied by the average annual number of actual test year existing customers. The result of that calculation is compared to the actual deferred revenue for the same 12-month period. The difference between the actual deferred revenue, and the calculated value, is then added to, or subtracted from, the total deferred balance by Rate Group. This calculation is shown in Table 1-30.

[53] The source entry for Deferral – Surcharge (Rebate), Line 15) is "(12) - (15)". This notation should be corrected to "(11 - 15)". However, the calculation is correct.
[54] Table 1-28, line 24, (Rebate/Surcharge) Balance, last column.
[55] Letter of Joe Miller, Avista Senior Manager of Rates and Tariffs, Regulatory Affairs to Amanda Maxwell, Executive Director and Secretary, Washington Utilities and Transportation Commission, re: Tariff WN U-29, Natural Gas Service Natural Gas Decoupling Rate Adjustment, dated May 27, 2022, P. 2 of 5.

Table 1-34: 2021 Natural Gas Decoupling - Residential.

Avista Utilities
Decoupling Mechanism
UG-190335 Base effective 4/1/2020 & UG-200901 Base Effective 10-1-2021
Development of WA Natural Gas Deferrals (Calendar Year 2021)

Line No.		Source	Revised Jan-20	Revised Feb-20	Revised Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Total
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
	Residential Group														
1	Actual Customers	Revenue System	170,038	170,038	170,038	170,295	170,263	170,396	170,444	170,724	170,589	171,132	171,256	171,774	
2	Actual Usage ("Therms)	Revenue System	20,684,875	21,500,858	14,765,518	8,962,165	4,466,068	2,745,599	2,048,449	2,330,904	3,156,001	8,316,628	14,219,304	23,797,281	
3	Actual Base Rate Revenue	Revenue System	$ 11,496,790	$ 11,782,889	$ 8,420,598	$ 5,288,493	$ 3,492,252	$ 2,800,621	$ 2,499,581	$ 2,697,286	$ 2,845,244	$ 5,661,049	$ 7,955,293	$ 13,471,458	
4	Actual Fixed Charge Revenue	Revenue System	$ 1,564,897	$ 1,561,449	$ 1,768,948	$ 1,636,898	$ 1,637,981	$ 1,647,015	$ 1,644,906	$ 1,648,687	$ 1,643,700	$ 1,648,858	$ 1,648,972	$ 1,650,321	
5	New Customers	Revenue System	6,135	5,922	6,787	6,599	6,840	6,970	7,188	7,394	7,540	4,403	4,679	4,909	
6	New Customer Usage (Therms)	Revenue System	701,592	695,498	639,367	402,019	201,657	114,045	68,683	57,571	77,980	116,188	292,557	513,683	
7	New Customer Base Rate Revenue	Revenue System	$ 389,558	$ 384,688	$ 360,703	$ 241,488	$ 152,690	$ 115,222	$ 98,471	$ 94,893	$ 105,266	$ 95,884	$ 192,178	$ 316,498	
8	New Customer Fixed Charge Revenue	Revenue System	$ 58,748	$ 56,269	$ 64,515	$ 62,957	$ 65,237	$ 66,168	$ 68,375	$ 70,158	$ 71,469	$ 41,876	$ 44,698	$ 46,750	
9	Actual/Test Year Existing Customers	(1) - (5)	163,903	164,116	163,251	163,696	163,423	163,426	163,256	163,330	163,049	166,729	166,577	166,865	1,971,621
10	Monthly Decoupled Revenue per Customer	Attachment 4, Page 3	$64.18	$48.76	$44.02	$27.53	$16.27	$8.72	$6.48	$6.25	$8.69	$31.60	$53.33	$70.53	$386.36
11	Decoupled Revenue	(9) x (10)	$ 10,519,508	$ 8,002,021	$ 7,185,922	$ 4,506,298	$ 2,659,549	$ 1,424,558	$ 1,057,670	$ 1,021,122	$ 1,416,884	$ 5,267,839	$ 8,883,389	$ 11,724,193 *	$ 63,668,952
12	Actual Usage /Test Year Existing	(2) - (6)	19,983,283	20,805,360	14,126,150	8,560,146	4,264,411	2,631,554	1,979,766	2,273,333	3,078,021	8,200,440	13,926,747	23,283,597	123,112,807
13	Actual Base Rate Revenue / Test Year Existing	(3) - (7)	$ 11,107,231	$ 11,398,201	$ 8,059,895	$ 5,047,004	$ 3,339,562	$ 2,685,399	$ 2,401,111	$ 2,602,392	$ 2,739,978	$ 5,565,165	$ 7,763,115	$ 13,154,960	$ 75,864,015
14	Actual Fixed Charge Revenue / Test Year Existing	(4) - (8)	$ 1,506,149	$ 1,505,180	$ 1,704,433	$ 1,573,941	$ 1,572,744	$ 1,580,848	$ 1,576,531	$ 1,578,530	$ 1,572,231	$ 1,606,982	$ 1,604,275	$ 1,603,572	$ 18,985,414
15	Customer Decoupled Payments	(13) - (14)	$ 9,601,082	$ 9,893,021	$ 6,355,462	$ 3,473,063	$ 1,766,818	$ 1,104,552	$ 824,579	$ 1,023,863	$ 1,167,747	$ 3,958,183	$ 6,158,841	$ 11,551,389	$ 56,878,601
16	Residential Revenue Per Customer Received	(15) / (9)	$58.58	$60.28	$38.93	$21.22	$10.81	$6.76	$5.05	$6.27	$7.16	$23.74	$36.97	$69.23	
17	Deferral - Surcharge (Rebate)	(12) - (15)	$ 918,426	$ (1,891,001)	$ 830,460	$ 1,033,234	$ 892,730	$ 320,006	$ 233,090	$ (2,740)	$ 249,137	$ 1,309,656	$ 2,724,548	$ 172,804	$ 6,790,351
18	Deferral - Revenue Related Expenses	Rev Conv Factor	$ (40,553)	$ 83,497	$ (36,669)	$ (45,622)	$ (39,419)	$ (14,130)	$ (10,292)	$ 121	$ (11,001)	$ (57,256)	$ (119,112)	$ (7,555)	$ (297,989)
19		FERC Rate	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	
20	Interest on Deferral	Avg Balance Calc	$ 1,189	$ (67)	$ (1,440)	$ 969	$ 3,464	$ 5,043	$ 5,773	$ 6,087	$ 6,422	$ 8,458	$ 13,705	$ 17,494	$ 67,097
21	**Monthly Residential Deferral Totals**		**$ 879,061**	**$ (1,807,570)**	**$ 792,351**	**$ 988,580**	**$ 856,776**	**$ 310,919**	**$ 228,571**	**$ 3,467**	**$ 244,558**	**$ 1,260,858**	**$ 2,619,142**	**$ 182,744**	**$ 6,559,458**
22	Cumulative Deferral (Rebate) Balance	Σ((17) ,(18) , (20))	$ 879,061	$ (928,509)	$ (136,158)	$ 852,423	$ 1,709,199	$ 2,020,118	$ 2,248,689	$ 2,252,156	$ 2,496,715	$ 3,757,573	$ 6,376,714	**$ 6,559,458**	

*** As approved in Docket No. UG-190335, the Company is required to calculate decoupled revenue using YTD average customers, compare to what was recorded using monthly customer counts, and record the difference in December so that the annual decoupled revenue is based on YTD average customers. This amount includes that annual true-up that resulted in a decrease to decoupled revenue of $19,742.07.**

Natural Gas – Non-Residential (Schedule 175B)

Schedule 175B calculation for Electric Non-Residential steps follow. There are eight steps. The sequence of the line numbers are keyed to the eight steps, and to Table 1-29. Steps 1 through 5 are required to remove new customers (new hookups) from the calculation.

Step1: Deduct new hookup customers. The number of new hookup customers (Line 27) is deducted from the total actual number of customers (Line 23) to determine the actual number of test year existing customers each month. The result (actual number of customers after subtracting out new customers) is Test Year Existing Customers (Line 31).

Step 2: Calculate total Allowed Decoupled Revenue each month. This is calculated by multiplying the number of Actual Customers after removing new customers (Line 31) by the Monthly Decoupled Revenue per Customer (Line 32). The result is shown on Line 35.

Step 3: Deduct actual new hookup customer revenue from total actual revenue. This determines the actual test year existing customer revenue collected in the applicable month. To form this result, Actual Base Rate Revenue (Line 27) is adjusted by subtracting New Customer Base Rate Revenue (Line 31). The result is shown on Line 36.

Step 4: Deduct actual new hookup customer fixed charge revenue from total actual fixed charge revenue. Line 32, New Customer Basic Charge Revenue, is subtracted from Line 28, Actual Basic Charge Revenue. The result, Actual Basic Charge Revenue (Test Year Existing), is shown on Line 37.

Step 5: Deduct actual new hookup customer kWh sales from total actual kWh sales. This is Line 26 (Total Actual kWh Sales) minus Line 30 (New Customer Usage (kWh). The result is the Actual Usage (kWh) from which new customer actual usage has been removed. The result is shown in Line 38. Then, Actual Usage (kWh) in Line 38 is multiplied by the approved Retail Revenue Credit (Line 39). The result is the revenue collected related to the variable power supply (Variable Power Supply Payments in Line 40). When Step 5 is completed, all remaining quantities have been adjusted to remove new customers (new hookups).

Step 6: Compute Customer Decoupled Payments. Actual Decoupled Revenue is calculated by subtracting the Actual Basic Charge Revenue (Test Year Existing) in Line 37 and the Variable Power Supply Payments (Line 40) from the Actual Base Rate Revenue (Line 36) and is shown on Line 41.

Step 7: Compute Balance to be Deferred by the Company as a Surcharge or as a Rebate. The Balance (for each month) is computed by subtracting Customer Decoupled Payments (Line 37) from Decoupled Revenue (Line 33). The result (Deferral – Surcharge/Rebate) is shown on Line 39. This amount is then adjusted for Revenue Related Expenses (Line 44) and for interest at the FERC rate (Lines 44 and 45). The result is the Monthly Non-Residential Deferral Total (Line 47). These monthly amounts are cumulated in Line 48

Monthly Residential Deferral Total for each month is shown just below Line 12. This is the difference between the Actual Decoupled Revenue (Step 6; Line 9) and the Allowed Decoupled Revenue (Step 2; Line 3) plus any interest on the deferral. The Total Cumulative Deferral (Rebate)/Surcharge Balance is tracked in Line 48. The total cumulative deferral for Natural Gas Non-Residential is a surcharge to customers of $11,263,209.[56]

Step 8: Comparison. At the end of every 12-month deferral period, the annual decoupled revenue per customer, by rate group, will be multiplied by the average annual number of actual test year existing customers. The results of that calculation will be compared to the actual deferred revenue for the same 12-month period. The difference between the actual deferred revenue and the calculated value will be added to, or subtracted from, the total deferred balance by Rate Group. This calculation is shown in Table 1-30, and results in a decrease of $19,742.07 for the Residential Group and a decrease of $12,689.42 for the Non-Residential Group.[57]

[56] Table 1-15, line 48, Cumulative Deferral (Rebate/Surcharge) Balance.
[57] Table 1-16, Net increase (decrease) to Decoupled Revenue due to Average Calculation (middle of table for Residential; bottom line for Non-Residential).

Table 1-35: 2021 Natural Gas Decoupling - Non-Residential.

Avista Utilities
Decoupling Mechanism
UG-190335 Base effective 4/1/2020 & UG-200901 Base Effective 10/1/2021
Development of WA Natural Gas Deferrals (Calendar Year 2021)

Line No.		Source	Revised Jan-20	Revised Feb-20	Revised Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Total
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
	Non-Residential Group														
23	Actual Customers	Revenue System	3,182	3,182	3,182	3,195	3,179	3,181	3,196	3,193	3,192	3,210	3,225	3,253	
24	Actual Usage ("Therms)	Revenue System	7,591,558	7,598,557	6,994,946	4,053,887	2,846,431	1,971,230	1,689,800	1,930,413	2,393,928	4,327,020	5,630,045	9,023,138	
25	Actual Base Rate Revenue	Revenue System	$ 1,897,873	$ 2,381,220	$ 2,415,036	$ 1,529,319	$ 1,108,709	$ 862,281	$ 740,371	$ 776,531	$ 876,894	$ 1,321,635	$ 1,460,658	$ 2,486,342	
26	Actual Fixed Charge Revenue	Revenue System	$ 325,728	$ 317,031	$ 385,342	$ 343,857	$ 342,227	$ 343,652	$ 343,736	$ 343,772	$ 343,531	$ 363,468	$ 384,641	$ 389,100	
27	New Customers	Revenue System	46	49	58	56	63	62	65	69	74	37	41	48	
28	New Customer Usage (Therms)	Revenue System	185,880	212,999	245,547	124,307	86,274	49,014	36,011	31,807	39,268	21,805	44,814	174,933	
29	New Customer Base Rate Revenue	Revenue System	$ 50,878	$ 58,186	$ 67,909	$ 39,485	$ 31,604	$ 18,933	$ 15,856	$ 14,821	$ 17,540	$ 9,059	$ 16,526	$ 49,759	
30	New Customer Fixed Charge Revenue	Revenue System	$ 4,779	$ 4,987	$ 5,961	$ 5,954	$ 6,649	$ 6,531	$ 6,879	$ 6,945	$ 7,718	$ 3,567	$ 4,423	$ 5,979	
31	Test Year Existing Customers	(23) - (27)	3,136	3,133	3,124	3,139	3,116	3,119	3,131	3,124	3,118	3,173	3,184	3,205	37,702
32	Monthly Decoupled Revenue per Customer	Attachment 5, Page 3	$685.77	$646.17	$518.30	$402.99	$292.00	$212.46	$153.39	$167.80	$199.69	$399.48	$594.98	$744.05	$5,017.07
33	Decoupled Revenue	(31) x (32)	$ 2,150,581	$ 2,024,451	$ 1,619,165	$ 1,264,987	$ 909,857	$ 662,663	$ 480,250	$ 524,220	$ 622,629	$ 1,267,545	$ 1,894,419	$ 2,371,408 **	$ 15,792,174
34	Actual Usage (Therms) /Test Year Existing	(24) - (28)	7,405,678	7,385,558	6,749,398	3,929,580	2,760,157	1,922,216	1,653,788	1,898,606	2,354,660	4,305,215	5,585,230	8,848,204	54,798,292
35	Actual Base Rate Revenue / Test Year Existing	(25) - (29)	$ 1,846,995	$ 2,323,034	$ 2,347,127	$ 1,489,834	$ 1,077,105	$ 843,348	$ 724,515	$ 761,710	$ 859,354	$ 1,312,576	$ 1,444,132	$ 2,436,583	$ 17,466,313
36	Actual Fixed Charge Revenue / Test Year Existing	(26) - (30)	$ 320,949	$ 312,044	$ 379,381	$ 337,903	$ 335,578	$ 337,121	$ 336,857	$ 336,828	$ 335,813	$ 359,901	$ 380,218	$ 383,121	$ 4,155,711
37	Customer Decoupled Payments	(35) - (36)	$ 1,526,046	$ 2,010,991	$ 1,967,746	$ 1,151,931	$ 741,527	$ 506,227	$ 387,658	$ 424,882	$ 523,542	$ 952,675	$ 1,063,914	$ 2,053,462	$ 13,310,601
38	Non-Residential Revenue Per Customer Rece	(37) / (31)	$486.62	$641.87	$629.88	$366.97	$237.97	$162.30	$123.81	$136.01	$167.91	$300.24	$334.14	$640.71	
39	Deferral - Surcharge (Rebate)	(33) - (37)	$ 624,535	$ 13,461	$ (348,582)	$ 113,056	$ 168,330	$ 156,436	$ 92,592	$ 99,337	$ 99,087	$ 314,870	$ 830,505	$ 317,946	$ 2,481,573
40	Deferral - Revenue Related Expenses	Rev Conv Factor	$ (27,576)	$ (594)	$ 15,392	$ (4,992)	$ (7,433)	$ (6,907)	$ (4,088)	$ (4,386)	$ (4,375)	$ (13,765)	$ (36,308)	$ (13,900)	$ (108,934)
41		FERC Rate	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	
42	Interest on Deferral	Avg Balance Calc	$ 808	$ 1,636	$ 1,207	$ 905	$ 1,272	$ 1,696	$ 2,023	$ 2,277	$ 2,540	$ 3,083	$ 4,574	$ 6,074	$ 28,095
43	**Monthly Non-Residential Deferral Totals**		**$ 597,767**	**$ 14,503**	**$ (331,983)**	**$ 108,969**	**$ 162,170**	**$ 151,225**	**$ 90,526**	**$ 97,228**	**$ 97,252**	**$ 304,187**	**$ 798,771**	**$ 310,120**	**$ 2,400,734**
44	Cumulative Deferral (Rebate) Balance	Σ((39) ,(40) , (42))	$ 597,767	$ 612,269	$ 280,286	$ 389,255	$ 551,425	$ 702,650	$ 793,176	$ 890,404	$ 987,655	$ 1,291,842	$ 2,090,614	**$ 2,400,734**	
45	**Total Cumulative Deferral (Rebate)**	**(22) + (44)**	$ 1,476,828	$ (316,240)	$ 144,128	$ 1,241,678	$ 2,260,624	$ 2,722,768	$ 3,041,865	$ 3,142,560	$ 3,484,370	$ 5,049,415	$ 8,467,328	**$ 8,960,191**	

**** As approved in Docket No. UG-190335, the Company is required to calculate decoupled revenue using YTD average customers, compare to what was recorded using monthly customer counts, and record the difference in December so that the annual decoupled revenue is based on YTD average customers. This amount includes that annual true-up that resulted in a decrease to decoupled revenue of $12,689.42.**

Table 1-36: 2021 Annual True-Up for Natural Gas Residential and Non-Residential.

Purpose: As required by UG-190335 (UE-190222, consolidated) paragraph 111, the Company is required to calculate decoupled revenue using YTD average customers, compare to what was recorded using monthly customer counts, and record the difference so that the annual decoupled revenue is based on YTD average customers.

Procedure: Separately for residential and non-residential, calculated average customers and multiplied that by the sum of decoupled revenue by month to calculate total allowed decoupled revenue for the period based on average customers. Note, the average customer calculation and allowed revenue was broken out into the period of Jan - Sep 2021 when the UG-190335 authorized base was in effect and Oct - Dec 2021 when the UG-200901 authorized base was in effect. This was compared to the amount recorded using monthly actual customers and monthly decoupled revenue per customer. The difference was recorded with the monthly decoupled revenue for December 2021.

Residential				
Average Actual Customers (average of line 9 in Deferral Calc for Jan-Sep 2021 - UG-190335)			163,494	
Sum of Decoupled Revenue (sum of line 10 in Deferral Calc for Jan-Sep 2021 - UG-190335)		$	230.90	
Total Decoupled Revenue using Average Actual Customers		$	37,750,373.39	A
Average Actual Customers (average of line 9 in Deferral Calc for Oct-Dec 2021 - UG-200901)			166,724	
Sum of Decoupled Revenue (sum of line 10 in Deferral Calc for Oct-Dec 2021 - UG-200901)		$	155.46	
Total Decoupled Revenue using Average Actual Customers		$	25,918,578.20	A
Total Annual Authorized Decoupled Revenue using Average Actual Customers	∑ A	$	63,668,951.59	
Less January - November Decoupled Revenue (sum of line 11 in Deferral Calc for Jan-Dec 2021)			51,944,758.84	
Decoupled Revenue to record for December to reflect true-up		$	11,724,192.75	
December Actual Customers (line 9, column n in Deferral Calc)			166,865	
December Decoupled Revenue per Customer (line 10, column n in Deferral Calc)		$	70.53	
Total Decoupled Revenue for December using monthly actuals		$	11,769,665.72	
Net increase/(decrease) to Decoupled Revenue due to Average Calculation		$	(45,472.97)	
Non-Residential				
Average Actual Customers (average of line 33 in Deferral Calc for Jan-Sep 2021 - UG-190335)			3,127	
Sum of Decoupled Revenue (sum of line 34 in Deferral Calc for Jan-Sep 2021 - UG-190335)		$	3,278.56	
Total Decoupled Revenue using Average Actual Customers		$	10,250,977.41	B
Average Actual Customers (average of line 33 in Deferral Calc for Oct-Dec 2021 - UG-200901)			3,187	
Sum of Decoupled Revenue (sum of line 34 in Deferral Calc for Oct-Dec 2021 - UG-200901)		$	1,738.51	
Total Decoupled Revenue using Average Actual Customers		$	5,541,196.42	B
Total Annual Authorized Decoupled Revenue using Average Actual Customers	∑ B	$	15,792,173.83	
Less January - November Decoupled Revenue (sum of line 35 in Deferral Calc for Jan-Nov 2021)			13,420,765.61	
Decoupled Revenue to record for December to reflect true-up		$	2,371,408.22	
December Actual Customers (line 33, column n in Deferral Calc)			3,205	
December Decoupled Revenue per Customer (line 34, column n in Deferral Calc)		$	744.05	
Total Decoupled Revenue for December using monthly actuals		$	2,384,668.03	
Net increase/(decrease) to Decoupled Revenue due to Average Calculation		$	(13,259.81)	

Table 1-37: 2021 Natural Gas Residential Group Rate Determination.

Residential Natural Gas Service: Adjustments		
2021 Deferred Revenue	$	6,559,458
Add: Earnings Sharing/DSM Adjustment	$	(57,986)
Add: Prior Year Carryover Balance	$	24,802
Add: Interest through 7/31/2024	$	266,044
Add: Revenue Related Expense Adjustment	$	228,992
Total Requested Recovery	$	7,021,310
Customer Surcharge Revenue	$	5,378,553
Carryover Deferred Revenue	$	1,642,757

For the natural gas Non-Residential group, deferred revenue is in the surcharge direction with a decoupling surcharge to customers of $2,400,734.[58] Adjustments, conveyed in the annual filing, result in a Total Requested Recovery of $2,574,424, of which $2,574,424 is Customer Surcharge Revenue and $1,894,261 is Carryover Deferred Revenue (Table 1-38).[59,60]

Table 1-37: 2021 Natural Gas Non-Residential Rate Determination.

Non-Residential Natural Gas Service: Adjustments		
2021 Deferred Revenue	$	2,400,734
Add: Earnings Sharing/DSM Adjustment	$	(17,014)
Add: Prior Year Carryover Balance	$	18,077
Add: Interest through 7/31/2024	$	101,106
Add: Revenue Related Expense Adjustment	$	71,521
Total Requested Recovery	$	2,574,424
Customer Surcharge Revenue	$	2,574,424
Carryover Deferred Revenue	$	894,261

58 Table 1-15, Line 48, Cumulative Deferral (Rebate) Surcharge Balance, Dec-20 Column.
59 Letter, re: Tariff WN U-29, Natural Gas Service Decoupling Rate Adjustment from Joe Miller, Avista Senior Manager for Rates and Tariffs, Regulatory Affairs to Mark L. Johnson, Executive Director and Secretary, Washington Utilities and Transportation Commission dated May 26, 2021, P. 2 of 5.
60 Total Requested Recovery in Table 1-16 is off by one dollar, due to a rounding difference.

Earnings Test 2021

The decoupling mechanism, in Schedules 75D and 175D, provides for application of an earnings test, separately for electric service and for natural gas.

Schedule 75D – Electric Earnings Test

According to Schedule 75D, the decoupling mechanism for Electric is subject to an annual earnings test based on the Company's year-end Commission Basis Reports that reflect actual decoupling-related revenues and various normalizing adjustments. As shown in Table 1-15, Line 3, the calculated rate of return on a normalized basis in 2021 is 6.59%, which is less than the BASE rate of return of 7.19% (Line 4). This means there are no Electric Excess Earnings for 2021.

Table 1-38. 2021 Electric Earnings Test.

	2021 Commission Basis Earnings Test for Decoupling	
Line No.		Electric
1	Rate Base	$ 1,808,056,000
2	Net Income	$ 119,077,000
3	Calculated ROR	6.59%
4	Base ROR	7.19%
5	Excess ROR	-0.60%
6	Excess Earnings	$ -
7	Conversion Factor	0.756186
8	Excess Revenue (Excess Earnings/CF)	$ -
9	Sharing %	50%
10	2021 Total Earnings Test Sharing	**$ -**

Schedule 175D – Natural Gas Earnings Test

According to Schedule 175D, the decoupling mechanism for natural gas is subject to an annual earnings test based on the Company's year-end Commission Basis Reports that reflect actual decoupling-related revenues and various normalizing adjustments. As shown in Table 1-34, the rate of return on a normalized basis in 2020 is 7.10% (Line 3). This is less than the allowed return of 7.19% (Line 4). Since the normalized return is less than the Base ROR, the Earnings Test has no effect for natural gas customers for 2021.

Table 1-39: 2021 Natural Gas Earnings Test.

	2021 Commission Basis Earnings Test for Decoupling			
Line No.				Natural Gas
1	Rate Base		$	437,941,000
2	Net Income		$	31,094,000
3	Calculated ROR			7.10%
4	Base ROR	Pro-rated		7.19%
5	Excess ROR			-0.09%
6	Excess Earnings		$	-
7	Conversion Factor			0.756355
8	Excess Revenue (Excess Earnings/CF)		$	-
9	Sharing %			50%
10	2019 Total Earnings Test Sharing		**$**	**-**

Three-Percent Annual Rate Increase Limitation 2021

Decoupling annual rate adjustment surcharges are subject to a 3% annual rate increase limitation (there is no reciprocal limit on rebate rate adjustments). The test is to divide the *incremental* annual revenue to be collected (proposed surcharge revenue minus present surcharge revenue) by the total "normalized" revenue for the two Rate Groups for the most recent January through December.

Normalized revenue is determined by multiplying the weather-corrected usage for the period by the present rates in effect. If the incremental amount of the proposed surcharge exceeds 3%, only a 3% incremental rate increase will apply. Any remaining deferred revenue will be carried over to the following years.

Schedule 75E – Electric 3% Rate Increase Test

The Electric Incremental Surcharge Test is shown in Table 1-35. Specifications for the test limit the surcharge to 3%, with any remainder deferred to the following year. For Residential customers, the result for the Incremental Decoupling Recovery Rate is negative (Line 7), so there is no Carryover Deferred Revenue for Electric Residential Customers for 2021. For Non-Residential customers, the Incremental Surcharge result is negative (Line 7), so there is no Carryover Deferred Revenue for Electric Non-Residential Customers for 2021.

Table 1-40: 2021 Electric 3% Annual Rate Increase Limitation.

Line No.	**3% Incremental Surcharge Test**	Residential	Non-Residential
1	Revenue From 2021 Normalized Loads and Customers at Present Billing Rates (Note 1)	$ 236,287,828	$ 245,165,869
2	August 2022 - July 2023 Usage (kWhs)	2,479,103,469	2,081,609,218
3	Proposed Decoupling Recovery Rates	-$0.00234	$0.00132
4	Present Decoupling Surcharge Recovery Rates	-$0.00045	$0.00679
5	Incremental Decoupling Recovery Rates	-$0.00189	-$0.00547
6	Incremental Decoupling Recovery	$ (4,685,506)	$ (11,386,402)
7	Incremental Surcharge %	**-1.98%**	**-4.64%**
8	3% Test Adjustment (Note 2)	$ -	$ -
9	3% Test Rate Adjustment	$0.00000	$0.00000
10	Adjusted Proposed Decoupling Recovery Rates	-$0.00234	$0.00132
11	Adjusted Incremental Decoupling Recovery	$ (4,685,506)	$ (11,386,402)
12	Adjusted Incremental Surcharge %	**-1.98%**	**-4.64%**
	Notes		
	(1) Revenue from 2021 normalized loads and customers at present billing rates effective since November 1, 2021.		
	(2) The carryover balances will differ from the 3% adjustment amounts due to the revenue related expense gross up partially offset by additional interest on the outstanding balance during the amortization period.		

Schedule 175E – Natural Gas 3% Rate Increase Test

The Natural Gas Incremental Surcharge Test is shown in Table 1-36. The test limits the Residential and the Non-Residential Surcharge each to 3%. For both the Residential and the Non-Residential Groups, the incremental surcharge percent is above 3% (Line 7), so the surcharge for 2021 is set to 3% for each, and there is Carryover Deferred Revenue (Line 8) to be to be deferred to the following year.

Table 1-41. 2021 Natural Gas 3% Rate Increase Limitation.

Line No.	**3% Incremental Surcharge Test**	Residential	Non-Residential
1	Revenue From 2021 Normalized Loads and Customers at Present Billing Rates (Note 1)	$ 136,763,580	$ 40,127,787
2	August 2022 - July 2023 Usage	137,946,985	58,623,989
3	Proposed Decoupling Recovery Rates	$0.05125	$0.04436
4	Present Decoupling Surcharge Recovery Rates (2)	$0.00925	$0.00813
5	Incremental Decoupling Recovery Rates	$0.04200	$0.03623
6	Incremental Decoupling Recovery	$ 5,793,773	$ 2,123,947
7	Incremental Surcharge %	**4.24%**	**5.29%**
8	3% Test Adjustment (3)	$ (1,690,866)	$ (920,114)
9	3% Test Rate Adjustment	-$0.01226	-$0.01570
10	Adjusted Proposed Decoupling Recovery Rates	$0.03899	$0.02866
11	Adjusted Incremental Decoupling Recovery	$ 4,102,543	$ 1,203,550
12	Adjusted Incremental Surcharge %	**3.00%**	**3.00%**
	Notes		
	(1) Revenue from 2021 normalized loads and customers at present billing rates effective since November 1, 2021.		
	(3) The carryover balances will differ from the 3% adjustment amounts due to the revenue related expense gross up partially offset by additional interest on the outstanding balance during the amortization period.		

2022 Decoupling Mechanism – Electric (Schedule 75) and Natural Gas (Schedule 175)

In this section, we review analysis of data from 2022, used to develop amounts for decoupling revenue recovery from August 1, 2023, to July 31, 2024 (the third decoupling rate year of the three examined in this study). The decoupling mechanism is designed to arithmetically capture fixed costs from within the variable portion of the rate. Other fixed costs already accounted for in the customer charge are not included. The captured fixed cost from the variable portion of the rate, after adjustments, is recovered as deferred revenue during the rate year that begins August 1, 2023, by monthly allocation to customer bills according to a model.

As specified in Schedule 75 and Schedule 175, calculations were carried out separately and in parallel, for Residential and Non-Residential accounts. For each of these groups of accounts, the sum of monthly deferral amounts over calendar year 2022 is the cumulative deferral (rebate or surcharge). The cumulative deferral includes adjustments for prior year carryover balance, interest, and revenue related expense adjustment.

Electric Group 1 (Residential) and Group 2 (Non-Residential)

First the electric service analysis is reviewed, then the analysis for natural gas service.

<u>Decoupled Revenue per Customer - Residential and Non-Residential (Schedule 75A))</u>

For electric service, following steps in Schedule 75A, *Decoupled Revenue per Customer (by Rate Group)* is developed. Calculation of Decoupled Revenue per Customer (by Rate Group) is specified in seven steps in Schedule 75A.

Step 1: Step 1 is to enter the Total Normalized 12 Month Ending September 2021 Revenue, individually for each Rate Schedule. Table 1-37, Line 1 shows Total Normalized Net Revenue. Line 2 shows the Allowed Revenue Increase. The sum of Line 1 and Line 2 is the Proposed Base Rate Revenue (Line 3).

Step 2: Step 2 is to determine the Variable Power Supply Revenue (Line 6). This us shown is the product of Normalized kWh (Line 4) and Retail Revenue Adjustment from (Line 5).

Step 3: Step 3 is to enter Delivery and Power Plant Revenue (Line 7). This is constructed by subtraction of Variable Power Supply Revenue (Line 6) from the Total Normalized Revenue (Line 3).

Step 4: Step 4 is to Remove Basic Charge Revenue (Line 10). Because the decoupling mechanism only tracks revenue that varies with customer energy usage, revenue from already specified Fixed Charges is removed. Basic Charge Revenue is shown on Line 10. It is the product of the number of Customer Bills in the GRC test year (Line 8) and the Allowed Basic Charge (Line 9).

Step 5: In Step 5, the Decoupled Revenue is equal to the Delivery and Power Plant Revenue (Line 7) minus the Basic Charge Revenue (Line 10). Decoupled Revenue is shown on Line 11.

Step 6: In Step 6, (see Table 1-36) Decoupled Revenue (from Table 1-35, Line 11 is put on a per customer basis. The Decoupled Revenue (Residential) from Line 1 in Table 1-36 is divided by the approved Test Year number of residential customers (Table 1-36, Line 2). This determines the annual Allowed Decoupled Revenue per Customer, separately for the Electric Residential and Non-Residential customer groups (Table 1-36, Line 3).

Step 7: Step 7 converts the annual Allowed Decoupled Revenue per Customer (by Rate Group) into monthly values. The assignment of monthly values is carried out by modeling monthly kWh use (by Rate Group) in relationship to the annual kWh use for the test year. This modeling is shown in Table 1-39.

Kilowatt hours for Group 1 (Residential) for the test year are shown in Line 3 and for Group 2 (Non-Residential) in Line 6. Both monthly values and the annual kWh values are shown. Below the monthly values (Lines 4 and 7) monthly percentages are shown. Lines 11 and 14 use this percentage model, applied to annual Allowed Decoupled Revenue per Customer (by Rate Group), to generate monthly values.

The monthly values developed following the steps in Schedule 75A are then taken forward to be used in the implementation of Schedule 75B.

Table 1-42. 2022 Development of Electric Decoupled Revenue per Customer

Avista Utilities
Electric Decoupling Mechanism
Development of Decoupled Revenue by Rate Schedule - Electric
Washington Docket No. UE-220053 Compliance Filing

		TOTAL	RESIDENTIAL SCHEDULE 1,2	GENERAL SVC. SCH. 11,12,13	LG. GEN. SVC. SCH. 21,22,23	PUMPING SCH. 30, 31, 32	EX LG GEN SVC SCH. 25,25I	ST & AREA LTG SCH. 41-48
1	Total Normalized 12ME Sep 2021 Revenue	$ 550,652,000	$ 253,459,000	$ 81,570,000	$ 131,153,000	$ 14,579,000	$ 62,990,000	$ 6,901,000
2	Allowed Revenue Increase (Attachment 1)	$ 38,000,000	$ 26,025,000	$ 3,264,000	$ 5,247,000	$ 1,497,000	$ 1,258,000	$ 709,000
3	Proposed Base Rate Revenue	$ 588,652,000	$ 279,484,000	$ 84,834,000	$ 136,400,000	$ 16,076,000	$ 64,248,000	$ 7,610,000
4	Normalized kWhs (12ME Sep 2021 Test Year)	5,687,021,474	2,499,403,391	634,803,427	1,300,358,712	163,276,886	1,071,217,134	17,961,924
5	Retail Revenue Adjustment (line 14)	$ 0.01311	$ 0.01311	$ 0.01311	$ 0.01311	$ 0.01311	$ 0.01311	$ 0.01311
6	Variable Power Supply Revenue (L4 * L5)	$ 74,556,852	$ 32,767,178	$ 8,322,273	$ 17,047,703	$ 2,140,560	$ 14,043,657	$ 235,481
7	Delivery & Power Plant Revenue (L3 - L6)	$ 456,516,286	$ 246,716,822	$ 76,511,727	$ 119,352,297	$ 13,935,440		
8	Customer Bills (12ME Sep 2021 Test Year)	3,137,180	2,681,552	403,355	21,942	30,331		
9	Allowed Basic Charges		$ 9.00	$ 21.00	$ 600.00	$ 21.00		
10	Basic Charge Revenue (Ln 8 * Ln 9)	$ 46,406,574	$ 24,133,968	$ 8,470,455	$ 13,165,200	$ 636,951		
11	Decoupled Revenue	$ 410,109,712	$ 222,582,854	$ 68,041,272	$ 106,187,097	$ 13,298,489	Excluded From Decoupling	
12	Retail Revenue Adjustment - (Attachment 5 Approved	$0.01253						
13	Gross Up Factor for Revenue Related Exp	104.60%						
14	Grossed Up Retail Revenue Adjustment	$0.01311						

		Residential	Non-Residential Group
15	Average Number of Customers (Line 8 / 12)	223,463	37,969
16	Annual kWh	2,499,403,391	2,098,439,025
17	Basic Charge Revenues	24,133,968	22,272,606
18	Customer Bills	2,681,552	455,628
19	Average Basic Charge	$9.00	$48.88

Table 1-43. 2022 Electric Decoupled Revenue per Customer

Avista Utilities
Electric Decoupling Mechanism
Development of Annual Decoupled Revenue Per Customer - Electric
Washington Docket No. UE-220053 Compliance Filing

Line No.		Source	Residential	Non-Residential Schedules*
	(a)	(b)	(c)	(d)
1	Decoupled Revenues	Attachment 3, Page 1	$ 222,582,854	$ 187,526,858
2	Test Year # of Customers 12 ME 09.2021	Revenue Data	223,463	37,969
3	Decoupled Revenue per Customer	(1) / (2)	$ 996.06	$ 4,938.95

* Schedules 11, 12, 13, 21, 22, 23, 31, 32.

		Residential	Non-Residential Schedules*
Attachment 3, Page 2			
Revenues			
From revenue per customer		$ 222,582,556	$ 187,526,993
From basic charge		$ 24,133,968	$ 22,272,606
From power supply		$ 32,767,178	$ 27,510,536
Total		$ 279,483,702	$ 237,310,134

Table 1-44. 2022 Development of Monthly Electric Decoupled Revenue per Customer

Avista Utilities
Electric Decoupling Mechanism
Development of Monthly Decoupled Revenue Per Customer - Electric
Washington Docket No. UE-220053 Compliance Filing

Line No.		Source	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	TOTAL
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
1	**Electric Sales**														
2	*Residential*														
3	- Weather-Normalized kWh Sales	Monthly Test Year	269,928,495	231,695,829	237,266,610	182,595,902	169,557,272	145,316,369	202,830,169	207,412,726	155,120,595	174,601,948	234,301,988	288,775,489	2,499,403,391
4	- % of Annual Total	% of Total	10.80%	9.27%	9.49%	7.31%	6.78%	5.81%	8.12%	8.30%	6.21%	6.99%	9.37%	11.55%	100.00%
5	*Non-Residential**														
6	- Weather-Normalized kWh Sales	Monthly Test Year	170,832,385	156,477,576	170,321,875	156,304,005	178,484,305	191,690,896	188,791,635	196,116,120	177,255,646	187,317,716	153,304,398	171,542,469	2,098,439,025
7	- % of Annual Total	% of Total	8.14%	7.46%	8.12%	7.45%	8.51%	9.13%	9.00%	9.35%	8.45%	8.93%	7.31%	8.17%	100.00%
8	**Monthly Decoupled Revenue Per Customer ("RPC")**														
9	*Residential*														
10	-Allowed Decoupled RPC	Attachment 4, P. 2 L. 3													$ 996.06
11	- Monthly Decoupled RPC	(4) x (10)	$ 107.57	$ 92.34	$ 94.56	$ 72.77	$ 67.57	$ 57.91	$ 80.83	$ 82.66	$ 61.82	$ 69.58	$ 93.37	$ 115.08	$ 996.06
12	*Non-Residential**														
13	-Allowed Decoupled RPC	Attachment 4, P. 2 L. 3													$ 4,938.95
14	- Monthly Decoupled RPC	(7) x (13)	$ 402.08	$ 368.29	$ 400.87	$ 367.88	$ 420.09	$ 451.17	$ 444.35	$ 461.58	$ 417.19	$ 440.88	$ 360.82	$ 403.75	$ 4,938.95

* Schedules 11, 12, 13, 21, 22, 23, 31, 32.

Monthly Decoupling Deferral

Schedule 75B specifies the method for developing the *Monthly Decoupling Deferral* for electric service. Table 1-45 is in two sections. Electric Residential is developed in the top section; Electric Non-Residential is in the bottom section. Electric Residential deferred revenue for 2022 is a rebate to customers of $16,125,774 (Line 23, Total Column). Electric Non-Residential deferred revenue for 2022 is in the surcharge direction in the amount of $384,924 (Line 48, Total Column). These are intermediate results, subject to adjustment.

The calculation for Electric Residential steps follows. There are eight steps. The sequence of the line numbers in Table 1-45 are keyed to the eight steps. Steps 1 through 5 are required to remove new customers (new hookups) from the calculation.

Electric – Residential (Schedule 75B)

Step1: Deduct new hookup customers. New hookup customers (Line 5) are deducted from total actual number of customers (Line 1) to determine the actual number of test year existing customers each month. The result (actual number of customers after subtracting out new customers) is in Line 9.

Step 2: Calculate total Allowed Decoupled Revenue each month. This is calculated by multiplying the number of Actual Customers after removing new customers (Line 9) by the Monthly Decoupled Revenue per Customer (Line 10). The result is shown on Line 11.

Step 3: Deduct actual new hookup customer revenue from total actual revenue. This determines the actual test year existing customer revenue collected in the applicable month. To form this result, Actual Base Rate Revenue (Line 3) is adjusted by subtracting New Customer Base Rate Revenue (Line 7). The result is shown on Line 12.

Step 4: Deduct actual new hookup customer fixed charge revenue from total actual fixed charge revenue. Line 4, Actual Customer Basic Charge Revenue, minus Line 8, New Customer Basic Charge Revenue = Actual Basic Charge Revenue (Test Year Existing), shown on Line 13.

Step 5: Deduct actual new hookup customer kWh sales from total actual kWh sales. This is Total Actual kWh Sales (Line 2) minus New Customer Usage, kWh (Line 6). The result is the Actual Usage, kWh from which new customer actual usage has been removed (Line 14). Then, Actual Usage (kWh) in Line 14 is multiplied by the approved

Retail Revenue Credit (Line 15). The result is the revenue collected related to the variable power supply (Variable Power Supply Payments in Line 16). When Step 5 is completed, all remaining quantities have been adjusted to remove new customers (new hookups).

Step 6: Compute Customer Decoupled Payments. Customer Decoupled Payments (Line 17) = Actual Base Rate Revenue (Line 12) minus the Actual Basic Charge Revenue Test Year Existing (Line 13) minus Variable Power Supply Payments (Line 16).

Step 7: Compute Balance to be Deferred by the Company as a Surcharge or as a Rebate. The Balance (for each month) is computed by subtracting Customer Decoupled Payments (Line 17) from Decoupled Revenue (Line 11). The result (Deferral – Surcharge/Rebate) is shown on Line 19. This amount is then adjusted for Revenue Related Expenses (Line 20) and for interest at the FERC rate (rate in Line 21; amount in Line 22). The result is the Monthly Non-Residential Deferral Total (Line 23). These monthly amounts are cumulated in Line 23.

Step 8: Comparison. At the end of every 12-month deferral period, the annual decoupled revenue per customer, by rate group, will be multiplied by the average annual number of actual test year existing customers. The results of that calculation will be compared to the actual deferred revenue for the same 12-month period. The difference between the actual deferred revenue and the calculated value will be added to, or subtracted from, the total deferred balance by Rate Group. This calculation is shown in Table 1-46, and results in a decrease of $81,997.37. for Residential.[61]

<u>Electric – Non-Residential (Schedule 75B)</u>

Step1: Deduct new hookup customers. New hookup customers (Line 29) are deducted from the total actual number of customers (Line 25) to determine the actual number of test year existing customers each month. The result (actual number of customers after subtracting out new customers) is in Line 33.

Step 2: Calculate total Allowed Decoupled Revenue each month. This is calculated by multiplying the number of Actual Customers after removing new customers (Line 33) by the Monthly Decoupled Revenue per Customer (Line 34). The result is shown on Line 35.

[61] Table 1-46, Net increase/(decrease) to Decoupled Revenue due to Average Calculation (middle of table for Residential).

Step 3: Deduct actual new hookup customer revenue from total actual revenue. This determines the actual test year existing customer revenue collected in the applicable month. To form this result, Actual Base Rate Revenue (Line 27) is adjusted by subtracting New Customer Base Rate Revenue (Line 31). The result, Actual Base Rate Revenue/Test Year Existing, is shown on Line 36.

Step 4: Deduct actual new hookup customer fixed charge revenue from total actual fixed charge revenue. Line 32, New Customer Basic Charge Revenue, is subtracted from Line 28, Actual Basic Charge Revenue. The result, Actual Basic Charge Revenue (Test Year Existing), is shown on Line 37.

Step 5: Deduct actual new hookup customer kWh sales from total actual kWh sales. This is Total Actual kWh Sales (Line 26) minus New Customer Usage, kWh (Line 30). The result is the Actual Usage, kWh from which new customer actual usage has been removed (Line 14).

Then, Actual Usage (kWh) in Line 14 is multiplied by the approved Retail Revenue Credit (Line 15). The result is the revenue collected related to the variable power supply (Variable Power Supply Payments in Line 38). When Step 5 is completed, all remaining quantities have been adjusted to remove new customers (new hookups).

Step 6: Compute Customer Decoupled Payments. Actual Decoupled Revenue is calculated by subtracting the Actual Basic Charge Revenue (Test Year Existing) in Line 37 and the Variable Power Supply Payments (Line 40) from the Actual Base Rate Revenue (Line 36) and is shown on Line 41, Customer Decoupled Payments.

Step 7: Compute Balance to be Deferred by the Company as a Surcharge or as a Rebate. The Balance (for each month) is computed by subtracting Customer Decoupled Payments (Line 41) from Decoupled Revenue (Line 35). The result (Deferral – Surcharge/Rebate) is shown on Line 43.

This amount is then adjusted for Revenue Related Expenses (Line 44) and for interest at the FERC rate (rate on Line 45; amount on Line 46). The result is the Monthly Non-Residential Deferral Total (Line 47). These monthly amounts are cumulated in Line 48.

The Total Cumulative Deferral (Rebate)/Surcharge Balance is tracked on Line 49. The total cumulative deferral for Electric Non-Residential is a refund to customers of $15,740,850.[62]

Step 8: Comparison. At the end of every 12-month deferral period, the annual decoupled revenue per customer, by rate group, will be multiplied by the average annual number of actual test year existing customers. The results of that calculation will be

[62] Table 1-45, line 49, Total Cumulative Deferral (Rebate)/Surcharge) Balance, last column.

compared to the actual deferred revenue for the same 12-month period. The difference between the actual deferred revenue and the calculated value will be added to, or subtracted from, the total deferred balance by Rate Group. This calculation is shown in Table 1-46 and results an increase of $21,215.50 for Non-Residential.[63]

[63] Table 1-46, Net increase/(decrease) to Decoupled Revenue due to Average Calculation (bottom line for Non-Residential).

Table 1-45. 2022 Development of Electric Deferral

Avista Utilities
UE-200900 Base Effective 10/1/2021 & UE-220053 Base Effective 12/21/2022
Development of WA Electric Deferrals (Calendar Year 2022)

Line No.		Source	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22	Total
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
	Residential Group														
1	Actual Customers	Revenue System	225,340	225,717	227,174	226,203	226,093	226,925	226,281	227,405	227,331	227,745	228,126	228,468	
2	Actual Usage (kWhs)	Revenue System	298,119,667	244,172,704	232,185,970	201,122,968	170,060,699	152,339,120	204,164,001	243,398,035	165,011,836	157,554,288	259,935,819	326,483,029	
3	Actual Base Rate Revenue	Revenue System	$ 31,037,264	$ 24,795,549	$ 23,925,579	$ 20,482,252	$ 17,165,401	$ 15,556,305	$ 20,538,173	$ 24,510,120	$ 16,867,527	$ 16,166,683	$ 26,202,119	$ 34,651,046	
4	Actual Basic Charge Revenue	Revenue System	$ 1,937,178	$ 1,949,427	$ 2,319,363	$ 2,070,486	$ 2,071,053	$ 2,110,131	$ 2,082,672	$ 2,108,088	$ 2,090,421	$ 2,091,636	$ 2,080,899	$ 2,089,683	
5	New Customers	Revenue System	6,092	5,979	6,581	6,766	6,807	7,293	7,741	7,757	8,065	8,610	8,513	6,982	
6	New Customer Usage (kWhs)	Revenue System	6,690,600	5,966,653	5,382,277	4,504,116	4,066,391	3,357,456	3,676,368	4,956,756	4,566,925	3,815,379	6,192,117	8,787,345	
7	New Customer Base Rate Revenue	Revenue System	$ 696,383	$ 621,045	$ 561,826	$ 469,930	$ 426,600	$ 359,724	$ 392,623	$ 514,010	$ 477,865	$ 410,645	$ 643,597	$ 923,716	
8	New Customer Basic Charge Revenue	Revenue System	$ 55,008	$ 53,775	$ 59,247	$ 61,031	$ 61,281	$ 65,457	$ 69,561	$ 70,137	$ 72,702	$ 77,431	$ 76,563	$ 62,875	
9	Actual Customers/Test Year Existing	(1) - (5)	219,248	219,738	220,593	219,437	219,286	219,632	218,540	219,648	219,266	219,135	219,613	221,486	2,635,622
10	Monthly Decoupled Revenue per Customer	Attachment 3, Page 3	$98.18	$74.15	$82.10	$60.70	$60.39	$52.67	$69.52	$63.91	$55.14	$61.82	$78.34	$105.55	$71.87
11	Decoupled Revenue	(9) x (10)	$ 21,526,148	$ 16,292,582	$ 18,111,195	$ 13,320,682	$ 13,243,529	$ 11,568,593	$ 15,192,069	$ 14,038,192	$ 12,090,939	$ 13,547,426	$ 17,204,385	$ 23,295,840 A	$ 189,431,581
12	Actual Base Rate Revenue/Test Year Existing	(3) - (7)	$ 30,340,881	$ 24,174,504	$ 23,363,753	$ 20,012,322	$ 16,738,801	$ 15,196,581	$ 20,145,550	$ 23,996,110	$ 16,389,662	$ 15,756,038	$ 25,558,522	$ 33,727,330	$ 265,400,054
13	Actual Basic Charge Revenue/Test Year Existing	(4) - (8)	$ 1,882,170	$ 1,895,652	$ 2,260,116	$ 2,009,455	$ 2,009,772	$ 2,044,674	$ 2,013,111	$ 2,037,951	$ 2,017,719	$ 2,014,205	$ 2,004,336	$ 2,026,808	$ 24,215,969
14	Actual Usage (kWhs)/Test Year Existing	(2) - (6)	291,429,067	238,206,051	226,803,693	196,618,851	165,994,308	148,981,664	200,487,633	238,441,279	160,444,911	153,738,909	253,743,702	317,695,684	2,592,585,751
15	Retail Revenue Credit ($/kWh)	Attachment 3, Page 1	$ 0.01360	$ 0.01360	$ 0.01360	$ 0.01360	$ 0.01360	$ 0.01360	$ 0.01360	$ 0.01360	$ 0.01360	$ 0.01360	$ 0.01360	$ 0.01343	
16	Variable Power Supply Payments	(14) x (15)	$ 3,963,435	$ 3,239,602	$ 3,084,530	$ 2,674,016	$ 2,257,523	$ 2,026,151	$ 2,726,632	$ 3,242,801	$ 2,182,051	$ 2,090,849	$ 3,450,914	$ 4,265,423	$ 35,203,928
17	Customer Decoupled Payments	(12) - (13) -(16)	$ 24,495,276	$ 19,039,250	$ 18,019,106	$ 15,328,851	$ 12,471,507	$ 11,125,756	$ 15,405,807	$ 18,715,358	$ 12,189,892	$ 11,650,984	$ 20,103,272	$ 27,435,098	$ 205,980,156
18	Residential Revenue Per Customer Received	(17) / (9)	$111.72	$86.65	$81.68	$69.86	$56.87	$50.66	$70.49	$85.21	$55.59	$53.17	$91.54	$123.87	$78.15
19	Deferral - Surcharge (Rebate)	(11) - (17)	$ (2,969,128)	$ (2,746,668)	$ 92,089	$ (2,008,168)	$ 772,022	$ 442,837	$ (213,739)	$ (4,677,165)	$ (98,953)	$ 1,896,442	$ (2,898,886)	$ (4,139,258)	$ (16,548,575)
20	Deferral - Revenue Related Expenses	Rev Conv Factor	$ 130,438	$ 120,665	$ (4,046)	$ 88,222	$ (33,916)	$ (19,454)	$ 9,390	$ 205,475	$ 4,347	$ (83,313)	$ 127,352	$ 181,844	$ 727,003
21		FERC Rate	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.60%	3.60%	3.60%	4.91%	4.91%	4.91%	
22	Interest on Deferral	Avg Balance Calc	$ (3,844)	$ (11,255)	$ (14,722)	$ (17,242)	$ (18,890)	$ (17,368)	$ (18,962)	$ (26,033)	$ (32,960)	$ (41,573)	$ (43,704)	$ (57,649)	$ (304,202)
23	**Monthly Residential Deferral Totals**		**$ (2,842,534)**	**$ (2,637,258)**	**$ 73,321**	**$ (1,937,189)**	**$ 719,216**	**$ 406,015**	**$ (223,311)**	**$ (4,497,723)**	**$ (127,566)**	**$ 1,771,556**	**$ (2,815,238)**	**$ (4,015,063)**	**$ (16,125,774)**
24	Cumulative Deferral (Rebate)/Surcharge Balance	Σ((19) ,(20) , (22))	$ (2,842,534)	$ (5,479,791)	$ (5,406,470)	$ (7,343,659)	$ (6,624,443)	$ (6,218,428)	$ (6,441,739)	$ (10,939,462)	$ (11,067,028)	$ (9,295,473)	$ (12,110,711)	**$ (16,125,774)**	

Note: Table continues, below.

Avista Utilities
UE-200900 Base Effective 10/1/2021 & UE-220053 Base Effective 12/21/2022
Development of WA Electric Deferrals (Calendar Year 2022)

Line No.		Source	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22	Total
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
	Non-Residential Group														
25	Actual Customers	Revenue System	38,010	38,075	39,207	38,504	38,259	39,067	38,514	38,529	38,653	38,878	38,679	38,428	
26	Actual Usage (kWhs)	Revenue System	175,691,548	164,561,731	175,406,919	170,901,384	155,518,259	172,150,216	200,818,471	205,401,549	172,924,994	187,334,260	182,018,076	189,904,324	
27	Actual Base Rate Revenue	Revenue System	$ 19,617,944	$ 17,655,936	$ 19,148,228	$ 18,770,513	$ 16,893,514	$ 18,511,594	$ 21,264,457	$ 20,829,651	$ 18,508,860	$ 19,759,671	$ 19,526,881	$ 20,374,500	
28	Actual Basic Charge Revenue	Revenue System	$ 1,606,877	$ 1,593,727	$ 1,899,297	$ 1,696,030	$ 1,687,529	$ 1,711,619	$ 1,681,985	$ 1,680,574	$ 1,691,520	$ 1,694,725	$ 1,620,157	$ 1,719,490	
29	New Customers	Revenue System	1,937	1,887	2,022	2,082	2,158	2,246	2,344	2,326	2,470	2,596	2,611	2,129	
30	New Customer Usage (kWhs)	Revenue System	8,873,829	6,284,484	5,640,904	5,606,647	6,138,318	5,626,401	5,938,704	7,662,893	7,458,600	7,426,669	7,484,847	7,087,127	
31	New Customer Base Rate Revenue	Revenue System	$ 981,336	$ 710,416	$ 662,659	$ 673,348	$ 722,235	$ 675,100	$ 712,237	$ 867,549	$ 856,429	$ 862,763	$ 871,139	$ 810,774	
32	New Customer Basic Charge Revenue	Revenue System	$ 62,764	$ 58,297	$ 64,238	$ 66,333	$ 70,697	$ 69,765	$ 72,622	$ 71,793	$ 75,255	$ 79,241	$ 78,060	$ 63,790	
33	Actual Customers/Test Year Existing	(25) - (29)	36,073	36,188	37,185	36,422	36,101	36,821	36,170	36,203	36,183	36,282	36,068	36,299	435,995
34	Monthly Decoupled Revenue per Customer	Attachment 3, Page 3	$404.62	$380.46	$372.00	$363.72	$392.96	$408.58	$456.79	$436.78	$389.50	$420.52	$365.86	$403.60	$399.62
35	Decoupled Revenue	(33) x (34)	$ 14,596,758	$ 13,768,069	$ 13,832,765	$ 13,247,432	$ 14,186,303	$ 15,044,483	$ 16,522,189	$ 15,812,686	$ 14,093,285	$ 15,257,210	$ 13,195,700	$ 14,674,370	$ 174,230,252
36	Actual Base Rate Revenue/Test Year Existing	(27) - (31)	$ 18,636,608	$ 16,945,520	$ 18,485,569	$ 18,097,165	$ 16,171,279	$ 17,836,495	$ 20,552,220	$ 19,962,102	$ 17,652,430	$ 18,896,908	$ 18,655,742	$ 19,563,725	$ 221,455,763
37	Actual Basic Charge Revenue/Test Year Existing	(28) - (32)	$ 1,544,113	$ 1,535,430	$ 1,835,059	$ 1,629,697	$ 1,616,832	$ 1,641,854	$ 1,609,363	$ 1,608,780	$ 1,616,265	$ 1,615,484	$ 1,542,097	$ 1,655,700	$ 19,450,674
38	Actual Usage (kWhs)/Test Year Existing	(26) - (30)	166,817,719	158,277,247	169,766,015	165,294,737	149,379,941	166,523,815	194,879,767	197,738,656	165,466,393	179,907,591	174,533,229	182,817,197	2,071,402,306
39	Retail Revenue Credit ($/kWh)	Attachment 3, Page 1	$ 0.01360	$ 0.01360	$ 0.01360	$ 0.01360	$ 0.01360	$ 0.01360	$ 0.01360	$ 0.01360	$ 0.01360	$ 0.01360	$ 0.01360	$ 0.01343	
40	Variable Power Supply Payments	(38) x (39)	$ 2,268,721	$ 2,152,571	$ 2,308,818	$ 2,248,008	$ 2,031,567	$ 2,264,724	$ 2,650,365	$ 2,689,246	$ 2,250,343	$ 2,446,743	$ 2,373,652	$ 2,454,527	$ 28,139,285
41	Customer Decoupled Payments	(36) - (37) -(40)	$ 14,823,775	$ 13,257,519	$ 14,341,692	$ 14,219,459	$ 12,522,879	$ 13,929,917	$ 16,292,492	$ 15,664,076	$ 13,785,823	$ 14,834,681	$ 14,739,993	$ 15,453,498	$ 173,865,804
42	Non-Residential Revenue Per Customer Received	(41) / (33)	$410.94	$366.35	$385.68	$390.41	$346.88	$378.31	$450.44	$432.67	$381.00	$408.87	$408.67	$425.73	$398.78
43	Deferral - Surcharge (Rebate)	(35) - (41)	$ (228,017)	$ 510,550	$ (508,927)	$ (972,027)	$ 1,663,424	$ 1,114,566	$ 229,698	$ 148,610	$ 307,463	$ 422,529	$ (1,544,293)	$ (779,128)	$ 364,447
44	Deferral - Revenue Related Expenses	Rev Conv Factor	$ 10,017	$ (22,429)	$ 22,358	$ 42,703	$ (73,077)	$ (48,965)	$ (10,091)	$ (6,529)	$ (13,507)	$ (18,562)	$ 67,843	$ 34,228	$ (16,011)
45		FERC Rate	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.60%	3.60%	3.60%	4.91%	4.91%	4.91%	
46	Interest on Deferral	Avg Balance Calc	$ (295)	$ 70	$ 72	$ (1,845)	$ (955)	$ 2,639	$ 4,859	$ 5,416	$ 6,086	$ 9,754	$ 7,600	$ 3,086	$ 36,487
47	**Monthly Non-Residential Deferral Totals**		$ (218,295)	$ 488,191	$ (486,497)	$ (931,169)	$ 1,589,392	$ 1,068,241	$ 224,466	$ 147,498	$ 300,042	$ 413,721	$ (1,468,851)	$ (741,814)	$ 384,924
48	Cumulative Deferral (Rebate)/Surcharge Balance	Σ((43),(44),(46))	$ (218,295)	$ 269,896	$ (216,601)	$ (1,147,771)	$ 441,622	$ 1,509,862	$ 1,734,328	$ 1,881,826	$ 2,181,867	$ 2,595,588	$ 1,126,737	$ 384,924	
49	**Total Cumulative Deferral (Rebate)/Surcharge Balance**	(24) + (48)	$ (3,060,829)	$ (5,209,896)	$ (5,623,072)	$ (8,491,430)	$ (6,182,821)	$ (4,708,566)	$ (4,707,411)	$ (9,057,637)	$ (8,885,161)	$ (6,699,885)	$ (10,983,973)	$ (15,740,850)	

Note: December is calculated on a separate workpaper.

Table 1-46: 2022 Annual (December) True-Up: Electric Residential and Non-Res.

Purpose: As required by UE-190334 (UE-190222, consolidated) paragraph 111, the Company is required to calculate decoupled revenue using YTD average customers, compare to what was recorded using monthly customer counts, and record the difference so that the annual decoupled revenue is based on YTD average customers.

Procedure: Separately for residential and non-residential, calculated average customers and multiplied that by the sum of decoupled revenue by month to calculate total allowed decoupled revenue for the period based on average customers. Note, the average customer and decoupled revenue calculations include a proration for the period UE-200900 authorized base was in effect (1/1/2022 - 12/20/2022) and when the UE-220053 authorized base was in effect (12/21/2022 - 12/31/2022). This was compared to the amount recorded using monthly actual customers and monthly decoupled revenue per customer. The difference was recorded with the monthly decoupled revenue for December 2022.

Residential		
Average Actual Customers (average of line 9 in Deferral Calc)		219,635
Sum of Decoupled Revenue (sum of line 10 in Deferral Calc)	$	862.48
Total Annual Authorized Decoupled Revenue using Average Actual Customers	$	189,431,581.13
Less Jan - November Decoupled Revenue (sum of line 11 in Deferral Calc for Jan-Nov 2022)		166,135,740.77
Decoupled Revenue to record for December to reflect true-up	$	23,295,840.37
December Actual Customers (line 9, column n in Deferral Calc)		221,486
December Decoupled Revenue per Customer (line 10, column n in Deferral Calc)	$	105.55
Total Decoupled Revenue for December using monthly actuals	$	23,377,837.74
Net increase/(decrease) to Decoupled Revenue due to Average Calculation	$	(81,997.37)
Non-Residential		
Average Actual Customers (average of line 33 in Deferral Calc)		36,333
Sum of Decoupled Revenue (sum of line 34 in Deferral Calc)	$	4,795.38
Total Annual Authorized Decoupled Revenue using Average Actual Customers	$	174,230,251.61
Less Jan - November Decoupled Revenue (sum of line 35 in Deferral Calc for Jan-Nov 2022)		159,555,881.83
Decoupled Revenue to record for December to reflect true-up	$	14,674,369.78
December Actual Customers (line 33, column n in Deferral Calc)		36,299
December Decoupled Revenue per Customer (line 34, column n in Deferral Calc)	$	403.60
Total Decoupled Revenue for December using monthly actuals	$	14,650,154.27
Net increase/(decrease) to Decoupled Revenue due to Average Calculation	$	24,215.50

For Electric Residential service, the computations developed deferred revenue of $384,924 in the surcharge direction (from Table 1-47, Line 48, Cumulative Deferrals (Rebate)/Surcharge Balance, Dec-22 Column. This result is carried over to Table 1-47, Line 1, 2022 Deferred Revenue. Adjustments, including a Prior Year Carryover Balance in the rebate direction of $361,979 are shown in Table 1-47. The final result is a Customer Rebate amount of $18,646,149.[64] This rebate is shown in the Customer Surcharge Revenue line in Table 1-47 as ($18,646,149). There is no Carryover Deferred Revenue.

[64] Letter of Joe Miller, Senior Manager of Rates and Tariffs, Regulatory Affairs, Avista to Amanda Maxwell, Executive Director and Secretary, Washington Utilities and Transportation Commission, Re: Tariff WN U-28, Electric Service Electric Decoupling Rate Adjustment, May 31, 2023, Page 2 of 6.

Table 1-47: 2022 Electric Residential Group Rate Determination.

Residential Electric Service: Adjustments		
2022 Deferred Revenue	$	(16,125,744)
Add: Earnings Sharing/DSM Adjustment	$	-
Add: Prior Year Carryover Balance	$	(361,979)
Add: Interest through 7/31/2024	$	(1,299,204)
Add: Revenue Related Expense Adjustment	$	(859,222)
Total Requested Recovery	$	(18,646,149)
Customer Surcharge Revenue	$	(18,646,149)
Carryover Deferred Revenue	$	-

For Electric Non-Residential service, the computations developed deferred revenue of ($16,125,144) in the rebate direction (from Table 1-45, Line 48, Cumulative Deferrals (Rebate)/Surcharge Balance, Dec-22 Column. This result is carried over to Table 1-48, Line 1, 2022 Deferred Revenue. Adjustments, including a Prior Year Carryover Balance in the rebate direction of $2,145,962 are shown in Table 1-48. The final result is a Customer Rebate amount of $1,888,743.[65] This rebate is shown in the Customer Surcharge Revenue line in Table 1-48 as ($1,888,743). There is no Carryover Deferred Revenue.

Table 1-48: 2022 Electric Non-Residential Group Rate Determination.

Non-Residential Electric Service: Adjustments		
2022 Deferred Revenue	$	384,924
Add: Earnings Sharing/DSM Adjustment	$	-
Add: Prior Year Carryover Balance	$	(2,145,962)
Add: Interest through 7/31/2024	$	(49,720)
Add: Revenue Related Expense Adjustment	$	(77,985)
Total Requested Recovery	$	(1,888,743)
Customer Surcharge Revenue	$	(1,888,743)
Carryover Deferred Revenue	$	-

[65] Letter of Joe Miller, Senior Manager of Rates and Tariffs, Regulatory Affairs, Avista to Amanda Maxwell, Executive Director and Secretary, Washington Utilities and Transportation Commission, Re: Tariff WN U-28, Electric Service Electric Decoupling Rate Adjustment, May 31, 2023, Page 3 of 6.

Natural Gas Group 1 (Residential) and Group 2 (Non-Residential)

For natural gas, following steps in Schedule 175A, the *Decoupled Revenue per Customer (by Rate Group)* is developed. These steps are implemented in Table 1-49 and Table 1-50. Monthly Decoupled Revenue per Customer for Group 1: Residential and Group 2: Non-Residential are then used to develop the *Monthly Decoupling Deferral* for natural gas in Table 1-51, following the steps in Schedule 175B.

Schedule 175A – Decoupled Revenue per Customer

Step 1: Step 1 is to enter the Total Normalized Revenue, the final approved base rate revenue approved in the Company's last general rate case, for each rate class. Table 1-49, Line 1 shows 12 ME September 2021 Total Normalized Net Revenue. Line 2 shows Allowed Revenue Increase. The sum of Line 1 and Line 2 is shown on Line 3 as the Allowed Rate Base Recovery.

Step 2: Step 2 is to determine the Variable Gas Supply Revenue. This Variable Gas Supply Revenue is shown on Line 6. It is the product of Normalized Therms by rate schedule from the last approved general rate case from Line 4 times the PGA Rates from Line 5.

Step 3: Step 3 is to determine Delivery Revenue, which is entered on Line 7. To determine the Delivery Revenue, the Variable Gas Supply Revenue is (Line 6) is subtracted from the Allowed Base Rate Revenue (Line 3).

Step 4: Step 4 is to calculate the Basic Charge Revenue. Because the decoupling mechanism only tracks revenue that varies with customer energy usage, revenue from Fixed Charges is removed. It is the product of the number of Customer Bills in the test period on Line 8 times the Allowed Basic Charges (Line 9). The result, Basic Charge Revenue, is shown on Line 10.

Step 5: Determine the Allowed Decoupled Revenue. The Allowed Decoupled Revenue is equal to the Delivery (from Line 7) minus the Basic Charge Revenue (Line 10). The resulting Decoupled Revenue is shown on Line 11.

Step 6: In Step 6, Decoupled Revenue from Line 11 is put on a per customer basis. The Decoupled Revenue (by Rate Group) is divided by the approved Test Year number of customers (by Rate Group). This determines the annual Allowed Decoupled Revenue per Customer (by Rate Group) as shown in Table 1-50.

Step 7: Step 7 is different from the other steps because it converts the annual Allowed Decoupled Revenue per Customer (by Rate Group) into monthly values. The assignment of monthly values is carried out by first calculating the distribution of monthly therm use in the test year. This calculation is shown in Table 1-51. In Table 51, the therm use for Group 1 (Residential) for test year is shown on Line 4 and for Group 2 (Non-Residential) on Line 8. Both monthly therm values and the annual therm values are shown. Below the monthly values, percentages (Lines 5 and 9) are shown. Lines 14 and 18 show the use of these percentages, applied to annual Allowed Decoupled Revenue per Customer (by Rate Group) to generate monthly values.

These monthly values are then taken forward to be used in the implementation of Schedule 175B.

Table 1-49. 2022 Development of Natural Gas Decoupled Revenue per Customer

Natural Gas Decoupling Mechanism
Development of Decoupled Revenue by Rate Schedule - Natural Gas
Washington Docket No. UG-220054 Compliance Filing

	TOTAL	RESIDENTIAL SCHEDULE 101/102	GENERAL SVC. SCH. 111/112/116	LG. GEN. SVC. SCH. 121/122/126	INTERRUPTIBLE SCH 131	SCHEDULES 132	SCHEDULES 146 & 148
1 Total Normalized 12 ME Sep 2021 Revenue	$ 114,860,000	$ 89,621,000	$ 20,023,000	$ -	$ -	$ 225,000	$ 4,991,000
2 Allowed Revenue Increase (Attachment 2)	$ 7,500,000	$ 5,931,000	$ 1,325,000	$ -	$ -	$ 15,000	$ 229,000
3 Allowed Base Rate Revenue	$ 122,360,000	$ 95,552,000	$ 21,348,000	$ -	$ -	$ 240,000	$ 5,220,000
4 Normalized Therms (12ME Sep 2021 Test Year)	276,863,928	137,376,752	58,747,734	-	-	974,878	79,764,564
5 Schedule 150 PGA Rates excluded from base rates		$ -	$ -	$ -	$ -		
6 Variable Gas Supply Revenue	$ -	$ -	$ -	$ -	$ -		
7 Delivery Revenue (Ln 3 - Ln 6)	$ 116,900,000	$ 95,552,000	$ 21,348,000	$ -	$ -		
8 Customer Bills (12ME Sep 2021 Test Year)	2,078,989	2,040,304	38,169	0	0	-	516
9 Allowed Basic / Minimum Charges		$9.50	$128.72	$0.00	$0.00		
10 Basic Charge Revenue (Ln 8 * Ln 9)	$ 24,296,002	$ 19,382,888	$ 4,913,114	$ -	$ -		
11 Decoupled Revenue	$ 92,603,998	$ 76,169,112	$ 16,434,886	$ -	$ -	Excluded From Decoupling	

	Residential	Non-Residential Group
12 Average Number of Customers (Line 8 / 12)	170,025	3,181
13 Annual Therms	137,376,752	58,747,734
14 Basic Charge Revenues	$ 19,382,888	$ 4,913,114
15 Customer Bills	2,040,304	38,169
16 Average Basic Charge	$9.50	$128.72

Table 1-50. 2022 Natural Gas Decoupled Revenue per Customer

Avista Utilities
Natural Gas Decoupling Mechanism
Development of Decoupled Revenue Per Customer - Natural Gas
Washington Docket No. UG-220054 Compliance Filing

Line No.		Source	Residential Schedules*	Non-Residential Schedules**
	(a)	(b)	(c)	(d)
1	Decoupled Revenues	Attachment 4, Page 1	$ 76,169,112	$ 16,434,886
2	Test Year # of Customers 12 ME 09.2021	Revenue Data	170,025	3,181
3	Decoupled Revenue Per Customer	(1) / (3)	$ 447.99	$ 5,166.98

*Rate Schedules 101, 102.
**Rate Schedules 111, 112, 116, 131.

Table 1-51. 2022 Development of Monthly Natural Gas Decoupled Revenue per Customer

Avista Utilities
Natural Gas Decoupling Mechanism
'Development of Monthly Decoupled Revenue Per Customer - Natural Gas
Washington Docket No. UG-220054 Compliance Filing

Line No.		Source	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	TOTAL
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
1															
2	**Natural Gas Delivery Volume**														
3	*Residential**														
4	- Weather-Normalized Therm Delivery Volume	Monthly Rate Year	23,237,417	19,799,163	15,809,740	10,273,404	5,010,740	3,853,445	2,550,010	2,388,834	3,773,642	9,230,472	17,833,780	23,616,107	137,376,752
5	- % of Annual Total	% of Total	16.92%	14.41%	11.51%	7.48%	3.65%	2.81%	1.86%	1.74%	2.75%	6.72%	12.98%	17.19%	100.00%
6															
7	*Non-Residential***														
8	- Weather-Normalized Therm Delivery Volume	Monthly Rate Year	8,388,798	7,067,063	7,321,090	4,504,842	3,032,887	2,350,236	1,876,476	1,951,922	2,623,332	5,074,866	6,054,567	8,501,656	58,747,734
9	- % of Annual Total	% of Total	14.28%	12.03%	12.46%	7.67%	5.16%	4.00%	3.19%	3.32%	4.47%	8.64%	10.31%	14.47%	100.00%
10															
11	**Monthly Decoupled Revenue Per Customer ("RPC")**														
12	*Residential**														
13	-Allowed Decoupled RPC	Attachment 5, P. 2 L. 3													$ 447.99
14	-Monthly Decoupled RPC	(5) x (13)	$ 75.78	$ 64.57	$ 51.56	$ 33.50	$ 16.34	$ 12.57	$ 8.32	$ 7.79	$ 12.31	$ 30.10	$ 58.16	$ 77.01	$ 447.99
15															
16	*Non-Residential***														
17	-Allowed Decoupled RPC	Attachment 5, P. 2 L. 3													$ 5,166.98
18	-Monthly Decoupled RPC	(9) x (17)	$ 737.81	$ 621.56	$ 643.90	$ 396.21	$ 266.75	$ 206.71	$ 165.04	$ 171.68	$ 230.73	$ 446.34	$ 532.51	$ 747.74	$ 5,166.98
19															
20	*Rate Schedules 101, 102.														
21	**Rate Schedules 111, 112, 116, 131.														

Schedule 175B specifies the method for developing the *Monthly Decoupling Deferral* for natural gas service. For Group 1 (Residential), the monthly decoupling deferral amounts across 2022 sum to the annual total decoupling deferral for 2022. As shown in the top section of Table 1-43, Line 22, the annual total decoupling deferral for Residential natural gas is in the direction of a rebate to customers ($1,069,341). The annual total decoupling deferral for Non-Residential natural gas (bottom section of Table 1-43, Line 44) is $1,302,276 in the direction of a surcharge. These are intermediate results, subject to adjustment.

There are seven steps. The sequence of the line numbers in Table 1-44 are keyed to the eight steps. Steps 1 through 5 are required to remove new customers (new hookups) from the calculation.

Step1: Deduct new hookup customers. For Residential natural gas, the number of new hookup customers (Line 5) is deducted from the total actual number of customers (Line 1) to determine the actual number of test year existing customers each month (Line 9)

For Non-Residential natural gas, the number of new hookup customers (Line 27) is deducted from total actual number of customers (Line 23) to determine the actual number of test year existing customers each month. The result (actual number of customers after subtracting out new customers) is in Line 31.

Step 2: Calculate total Allowed Decoupled Revenue each month. For Residential, this is calculated by multiplying the number of Actual Customers after removing new customers (Line 9) by the Monthly Decoupled Revenue per Customer (Line 10). The result is shown on Line 11.
For Non-Residential, this is calculated by multiplying the number of Actual Customers after removing new customers (Line 31) by the Monthly Decoupled Revenue per Customer (Line 32). The result is shown on Line 33.

Step 3: Deduct actual new hookup customer revenue from total actual revenue. This determines the actual test year existing customer revenue collected in the applicable month. For Residential, Actual Base Rate Revenue (Line 3) is adjusted by subtracting New Customer Base Rate Revenue (Line 7). The result is shown on Line 13.
For Non-Residential, Actual Base Rate Revenue (Line 25) is adjusted by subtracting New Customer Base Rate Revenue (Line 29). The result is shown on Line 35.

Step 4: Deduct actual new hookup customer fixed charge revenue from total actual fixed charge revenue. For Residential, New Customer Fixed Charge Revenue (Line 8), is subtracted from Line 4, Actual Fixed Charge Revenue. The result, Actual Fixed Charge Revenue (Test Year Existing), is shown on Line 14. For Non-Residential, New Customer Fixed Charge Revenue (Line 30), is subtracted from Line 26, Actual Fixed Charge Revenue. The result, Actual Fixed Charge Revenue (Test Year Existing), is shown on Line 36.

Step 5: Calculate Actual Decoupled Revenue. For test year existing customers, subtract the basic charge revenue (Step 4) from the total actual monthly revenue (Step 3).

For Residential, this is Line 13 minus Line 14, and the result is shown in Line 15.

For Non-Residential, this is Line 35 minus Line 36, and the result is shown in Line 37.

When Step 5 is completed, all remaining quantities have been adjusted to remove new customers (new hookups).

Step 6: Compute the difference between the Actual Decoupled Revenue (Step 5) and the Allowed Decoupled Revenue (Step 2).

For Residential, this is Allowed Decoupled Revenue (Line 11) minus Actual Decoupled Revenue (Line 15). The result, Deferral – Surcharge (Rebate) is shown on Line 17.

For Non-Residential, this is Allowed Decoupled Revenue (Line 33) minus Actual Decoupled Revenue (Line 37). The result, Deferral – Surcharge (Rebate) is shown on Line 39.

Step 7: Compute Balance to be Deferred by the Company as a Surcharge or as a Rebate. The Balance (for each month) is computed by subtracting Customer Decoupled Payments (Line 17) from Decoupled Revenue (Line 11).[66] The result (Deferral – Surcharge/Rebate) is shown on Line 19. This amount is then adjusted for Revenue Related Expenses (Line 20) and for interest at the FERC rate (rate in Line 21; amount in Line 22). The result is the Monthly Non-Residential Deferral Total (Line 23). These monthly amounts are cumulated in Line 24. For Residential Natural Gas, the Total Cumulative Deferral (Rebate)/Surcharge Balance is tracked in Line 24. The total cumulative deferral for Residential Natural Gas is a refund to customers of $1,069,341.[67] Adjustments, conveyed in the filing, result in a final Residential surcharge of $801,749, which includes a prior year carryover balance of $1,852,020 and other adjustments (Table 1-52).[68]

[66] There is a typing error in Table 1-54 on Line 17. The Source on this line is "(12) – (15)". The Source should be corrected to (11) – (15). However, the calculation is correct.
[67] Table 1-38, line 23, Total Cumulative Deferral (Rebate)/Surcharge) Balance, last column.
[68] Letter, re: Tariff WN U-29, Natural Gas Service Decoupling Rate Adjustment from Joe Miller, Avista Senior Manager for Rates and Tariffs, Regulatory Affairs to Amanda Maxwell, Executive Director and Secretary, Washington Utilities and Transportation Commission dated May 31, 2023, P. 2 of 5.

Table 1-52: 2022 Natural Gas Residential Group Rate Determination.

Residential Natural Gas Service: Adjustments	
2022 Deferred Revenue	$ (1,069,341)
Add: Earnings Sharing/DSM Adjustment	$ -
Add: Prior Year Carryover Balance	$ 1,852,020
Add: Interest through 7/31/2024	$ (18,168)
Add: Revenue Related Expense Adjustment	$ 37,238
Total Requested Recovery	$ 801,749
Customer Surcharge Revenue	$ 801,749
Carryover Deferred Revenue	$ -

For Non-Residential Natural Gas, the Total Cumulative Deferral (Rebate)/Surcharge Balance is tracked in Line 44. The total cumulative deferral for Non-Residential Natural Gas is a surcharge to customers of $1,302,276.[69] Adjustments, conveyed in the filing, result in a final Non-Residential surcharge of $2,439,376, including a prior year carryover balance of $893,830 and other adjustments (Table 1-53).[70]

Table 1-53: 2022 Non-Residential Group Rate Determination.

Non-Residential Natural Gas Service: Adjustments	
2022 Deferred Revenue	$ 1,302,276
Add: Earnings Sharing/DSM Adjustment	$ -
Add: Prior Year Carryover Balance	$ 893,830
Add: Interest through 7/31/2024	$ 133,503
Add: Revenue Related Expense Adjustment	$ 109,587
Total Requested Recovery	$ 2,439,196
Customer Surcharge Revenue	$ 2,439,196
Carryover Deferred Revenue	$ -

[69] Table 1-53, line 1; also Table 1-54. 2022 Development of Natural Gas Deferral, Line 44, Col. for Dec 22.
[70] Letter, re: Tariff WN U-29, Natural Gas Service Decoupling Rate Adjustment from Joe Miller, Avista Senior Manager for Rates and Tariffs, Regulatory Affairs to Amanda Maxwell, Executive Director and Secretary, Washington Utilities and Transportation Commission dated May 31, 2023, P. 3 of 5.

Table 1-54. 2022 Development of Natural Gas Deferral

Avista Utilities
UG-200901 Base effective 10/1/2021 & UG-220054 Base Effective 12/21/2022
Development of WA Natural Gas Deferrals (Calendar Year 2022)

Line No.		Source	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22	Total
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
	Residential Group														
1	Actual Customers	Revenue System	171,222	172,123	172,311	171,878	171,972	172,276	171,944	172,697	172,525	173,078	173,064	173,277	
2	Actual Usage ("Therms)	Revenue System	24,141,719	19,934,381	14,505,566	12,164,376	7,551,453	3,523,739	2,229,894	1,990,698	2,613,036	5,706,305	21,188,427	26,644,710	
3	Actual Base Rate Revenue	Revenue System	$ 16,278,380	$ 12,143,142	$ 9,194,876	$ 7,613,021	$ 5,236,420	$ 3,052,464	$ 2,735,719	$ 2,495,087	$ 2,973,593	$ 4,046,731	$ 9,960,873	$ 16,063,880	
4	Actual Fixed Charge Revenue	Revenue System	$ 1,582,909	$ 1,580,810	$ 1,785,307	$ 1,651,167	$ 1,647,338	$ 1,675,182	$ 1,656,962	$ 1,668,096	$ 1,661,351	$ 1,664,609	$ 1,657,076	$ 1,664,875	
5	New Customers	Revenue System	5,027	4,919	5,319	5,486	5,626	5,909	6,020	6,131	6,263	6,507	6,548	5,495	
6	New Customer Usage (Therms)	Revenue System	733,867	586,310	484,749	359,959	276,701	147,883	68,159	46,312	52,212	97,214	418,653	704,118	
7	New Customer Base Rate Revenue	Revenue System	$ 445,830	$ 358,010	$ 300,613	$ 232,206	$ 189,753	$ 127,268	$ 90,171	$ 80,566	$ 84,774	$ 110,000	$ 274,521	$ 433,567	
8	New Customer Fixed Charge Revenue	Revenue System	$ 47,890	$ 46,674	$ 50,531	$ 51,984	$ 53,447	$ 56,041	$ 57,257	$ 58,373	$ 59,656	$ 62,339	$ 62,482	$ 52,033	
9	Actual/Test Year Existing Customers	(1) - (5)	166,195	167,204	166,992	166,392	166,346	166,367	165,924	166,566	166,262	166,571	166,516	167,782	1,999,117
10	Monthly Decoupled Revenue per Customer	Attachment 4, Page 3	$68.62	$55.50	$47.89	$29.05	$19.22	$9.76	$8.46	$8.42	$8.62	$31.60	$53.33	$72.83	$413.29
11	Decoupled Revenue	(9) x (10)	$ 11,403,480	$ 9,280,066	$ 7,997,292	$ 4,832,923	$ 3,196,506	$ 1,623,893	$ 1,403,708	$ 1,402,411	$ 1,433,693	$ 5,262,847	$ 8,880,136	$ 12,084,082 A	$ 68,801,036
12	Actual Usage /Test Year Existing	(2) - (6)	23,407,852	19,348,071	14,020,817	11,804,417	7,274,752	3,375,856	2,161,734	1,944,385	2,560,824	5,609,092	20,769,773	25,940,592	138,218,167
13	Actual Base Rate Revenue / Test Year Existing	(3) - (7)	$ 15,832,549	$ 11,785,133	$ 8,894,264	$ 7,380,815	$ 5,046,667	$ 2,925,197	$ 2,645,549	$ 2,414,521	$ 2,888,819	$ 3,936,730	$ 9,686,351	$ 15,630,313	$ 89,066,907
14	Actual Fixed Charge Revenue / Test Year Existing	(4) - (8)	$ 1,535,020	$ 1,534,136	$ 1,734,776	$ 1,599,183	$ 1,593,891	$ 1,619,141	$ 1,599,705	$ 1,609,722	$ 1,601,695	$ 1,602,270	$ 1,594,594	$ 1,612,842	$ 19,236,973
15	Customer Decoupled Payments	(13) - (14)	$ 14,297,530	$ 10,250,997	$ 7,159,488	$ 5,781,633	$ 3,452,776	$ 1,306,056	$ 1,045,844	$ 804,799	$ 1,287,124	$ 2,334,460	$ 8,091,757	$ 14,017,471	$ 69,829,933
16	Residential Revenue Per Customer Received	(15) / (9)	$86.03	$61.31	$42.87	$34.75	$20.76	$7.85	$6.30	$4.83	$7.74	$14.01	$48.59	$83.55	
17	Deferral - Surcharge (Rebate)	(12) - (15)	$ (2,894,050)	$ (970,931)	$ 837,805	$ (948,710)	$ (256,270)	$ 317,838	$ 357,864	$ 597,612	$ 146,569	$ 2,928,387	$ 788,379	$ (1,933,389)	$ (1,028,897)
18	Deferral - Revenue Related Expenses	Rev Conv Factor	$ 126,522	$ 42,447	$ (36,627)	$ 41,476	$ 11,204	$ (13,895)	$ (15,645)	$ (26,126)	$ (6,408)	$ (128,023)	$ (34,466)	$ 84,524	$ 44,981
19		FERC Rate	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.60%	3.60%	3.60%	4.91%	4.91%	4.91%	
20	Interest on Deferral	Avg Balance Calc	$ (3,747.69)	$ (8,763)	$ (8,959)	$ (9,127)	$ (10,712)	$ (10,661)	$ (10,872)	$ (9,534)	$ (8,495)	$ (5,606)	$ 1,643	$ (590)	$ (85,425)
21	**Monthly Residential Deferral Totals**		**$ (2,771,275)**	**$ (937,246)**	**$ 792,219**	**$ (916,361)**	**$ (255,778)**	**$ 293,281**	**$ 331,347**	**$ 561,951**	**$ 131,666**	**$ 2,794,758**	**$ 755,555**	**$ (1,849,456)**	**$ (1,069,341)**
22	Cumulative Deferral (Rebate) Balance	Σ((17) ,(18) , (20))	$ (2,771,275)	$ (3,708,522)	$ (2,916,303)	$ (3,832,664)	$ (4,088,443)	$ (3,795,161)	$ (3,463,815)	$ (2,901,863)	$ (2,770,198)	$ 24,560	$ 780,115	**$ (1,069,341)**	

Note: Table continues on following page.

Avista Utilities
UG-200901 Base effective 10/1/2021 & UG-220054 Base Effective 12/21/2022
Development of WA Natural Gas Deferrals (Calendar Year 2022)

Line No.	(a)	Source (b)	Jan-22 (c)	Feb-22 (d)	Mar-22 (e)	Apr-22 (f)	May-22 (g)	Jun-22 (h)	Jul-22 (i)	Aug-22 (j)	Sep-22 (k)	Oct-22 (l)	Nov-22 (m)	Dec-22 (n)
	Non-Residential Group													
23	Actual Customers	Revenue System	3,651	2,900	3,366	3,304	3,302	3,381	3,314	3,361	3,354	3,356	3,385	3
24	Actual Usage ("Therms)	Revenue System	8,911,890	7,967,454	6,530,840	5,534,897	3,861,543	2,400,538	1,968,103	1,813,652	2,235,428	4,267,107	8,418,166	10,113
25	Actual Base Rate Revenue	Revenue System	$ 3,409,446	$ 2,558,346	$ 2,383,718	$ 1,876,699	$ 1,487,454	$ 1,061,047	$ 795,556	$ 821,185	$ 868,725	$ 998,302	$ 1,364,900	$ 3,234
26	Actual Fixed Charge Revenue	Revenue System	$ 373,897	$ 369,718	$ 444,113	$ 395,127	$ 394,595	$ 404,747	$ 395,900	$ 401,158	$ 401,540	$ 400,340	$ 403,849	$ 419
27	New Customers	Revenue System	56	55	65	65	70	72	73	74	79	90	87	
28	New Customer Usage (Therms)	Revenue System	214,127	170,857	116,646	137,700	119,796	95,403	91,553	105,933	105,227	168,684	225,347	268
29	New Customer Base Rate Revenue	Revenue System	$ 63,655	$ 51,363	$ 39,817	$ 41,740	$ 40,064	$ 31,494	$ 29,304	$ 31,144	$ 31,486	$ 47,995	$ 63,360	$ 81
30	New Customer Fixed Charge Revenue	Revenue System	$ 7,518	$ 6,454	$ 7,582	$ 7,684	$ 8,116	$ 8,448	$ 8,564	$ 8,681	$ 9,098	$ 10,440	$ 10,033	$ 9
31	Test Year Existing Customers	(23) - (27)	3,595	2,845	3,301	3,239	3,232	3,309	3,241	3,287	3,275	3,266	3,298	3
32	Monthly Decoupled Revenue per Customer	Attachment 5, Page 3	$736.83	$650.61	$526.63	$428.95	$276.98	$223.19	$181.77	$187.11	$231.70	$399.48	$594.98	$74
33	Decoupled Revenue	(31) x (32)	$ 2,648,919	$ 1,850,972	$ 1,738,392	$ 1,389,385	$ 895,202	$ 738,525	$ 589,128	$ 615,038	$ 758,821	$ 1,304,697	$ 1,962,247	$ 2,481
34	Actual Usage (Therms) /Test Year Existing	(24) - (28)	8,697,763	7,796,597	6,414,194	5,397,198	3,741,747	2,305,135	1,876,551	1,707,719	2,130,201	4,098,423	8,192,819	9,845
35	Actual Base Rate Revenue / Test Year Existing	(25) - (29)	$ 3,345,791	$ 2,506,983	$ 2,343,900	$ 1,834,959	$ 1,447,390	$ 1,029,554	$ 766,252	$ 790,040	$ 837,239	$ 950,307	$ 1,301,539	$ 3,153
36	Actual Fixed Charge Revenue / Test Year Existing	(26) - (30)	$ 366,380	$ 363,264	$ 436,531	$ 387,443	$ 386,479	$ 396,298	$ 387,336	$ 392,476	$ 392,443	$ 389,900	$ 393,817	$ 409
37	Customer Decoupled Payments	(35) - (36)	$ 2,979,411	$ 2,143,719	$ 1,907,370	$ 1,447,516	$ 1,060,911	$ 633,255	$ 378,917	$ 397,564	$ 444,796	$ 560,407	$ 907,723	$ 2,743
38	Non-Residential Revenue Per Customer Receiv	(37) / (31)	$828.77	$753.50	$577.82	$446.90	$328.25	$191.37	$116.91	$120.95	$135.82	$171.59	$275.23	$8
39	Deferral - Surcharge (Rebate)	(33) - (37)	$ (330,492)	$ (292,747)	$ (168,978)	$ (58,131)	$ (165,709)	$ 105,270	$ 210,211	$ 217,474	$ 314,025	$ 744,290	$ 1,054,524	$ (262
40	Deferral - Revenue Related Expenses	Rev Conv Factor	$ 14,448	$ 12,798	$ 7,387	$ 2,541	$ 7,244	$ (4,602)	$ (9,190)	$ (9,508)	$ (13,729)	$ (32,539)	$ (46,102)	$ 11
41		FERC Rate	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.60%	3.60%	3.60%	4.91%	4.91%	4
42	Interest on Deferral	Avg Balance Calc	$ (428)	$ (1,236)	$ (1,837)	$ (2,137)	$ (2,432)	$ (2,517)	$ (2,343)	$ (1,737)	$ (980)	$ 731	$ 4,253	$ 5
43	**Monthly Non-Residential Deferral Totals**		**$ (316,471)**	**$ (281,185)**	**$ (163,428)**	**$ (57,726)**	**$ (160,897)**	**$ 98,150**	**$ 198,678**	**$ 206,230**	**$ 299,317**	**$ 712,481**	**$ 1,012,675**	**$ (245**
44	Cumulative Deferral (Rebate) Balance	Σ((39),(40),(42))	$ (316,471)	$ (597,656)	$ (761,084)	$ (818,810)	$ (979,707)	$ (881,556)	$ (682,879)	$ (476,649)	$ (177,332)	$ 535,149	$ 1,547,824	$ 1,302
45	**Total Cumulative Deferral (Rebate)**	(22) + (44)	$ (3,087,747)	$ (4,306,178)	$ (3,677,387)	$ (4,651,474)	$ (5,068,149)	$ (4,676,718)	$ (4,146,693)	$ (3,378,512)	$ (2,947,529)	$ 559,710	$ 2,327,940	$ 232

Note: For December (only) there is an additional workpaper.

2022 Earnings Test

The decoupling mechanism, in Schedules 75D and 175D provides for application of an earnings test,[71] separately for electric and for natural gas.[72]

Schedule 75D – Electric Earnings Test

According to Schedule 75D, the decoupling mechanism for decoupled electric customers is subject to an annual earnings test based on the Company's year-end Commission Basis Reports that reflect actual decoupling-related revenues and various normalizing adjustments. As shown in Table 1-55, Line 3, the rate of return on a normalized basis in 2022 is 6.12%. This is less than the 7.03% allowed return. If the return on a normalized basis had been above 7.03%, one-half of the revenue in excess of the allowed rate of return would have been shared with customers through the decoupling rate adjustment. Since the return on a normalized basis is less than the allowed rate of return, no earnings' sharing adjustment is applied to the 2022 deferred balances for Residential or for Non-Residential Electric Service.

Table 1-55. 2022 Electric Earnings Test

	2022 Commission Basis Earnings Test for Decoupling	
Line No.		Electric
1	Rate Base	$ 2,019,378,000
2	Net Income	$ 123,620,000
3	Calculated ROR	6.12%
4	Base ROR	7.03%
5	Excess ROR	-0.91%
6	Excess Earnings	$ -
7	Conversion Factor	0.755295
8	Excess Revenue (Excess Earnings/CF)	$ -
9	Sharing %	50%
10	2021 Total Earnings Test Sharing	**$ -**

[71] Information on the background of the Earnings Test is limited to information provided in the Tariff. In response to Data Request 092, Avista states that "[t]he calculation of excess earnings was agreed upon as part of the Settlement process in Docket Nos. 140188 and 140189. All information regarding the excess earnings test is included in the Tariff Schedule 75D."

[72] Rate of Return is not related to the operation of the 3% cap. In response to DR 091, Avista states that "Rate of Return (ROR) is net income divided by rate base for a given annual period. The combination of three elements, namely revenues, expenses, and rate base, determine the resulting ROR. Changes to the relationship among all of these elements will impact the actual or normalized actual ROR achieved each year. The 3% cap impacts the timing of amortization of prior year deferred revenue and as such does not impact earnings or rate base during the amortization period because surcharge revenues from customers are offset by deferred revenue amortization for a net income impact of $0 and the deferred revenue on the balance sheet is not included in rate base."

Schedule 175D – Natural Gas Earnings Test

According to Schedule 175D, the decoupling mechanism for natural gas is subject to an annual earnings test based on the Company's year-end Commission Basis Reports that reflect actual decoupling-related revenues and various normalizing adjustments. As shown in Table 1-56, the rate of return on a normalized basis in 2012 is 6.35% (Line 3). This is less than the 7.03% allowed return (Line 4). Since the calculated rate of return is less than the allowed rate of return, no earnings' sharing adjustment is applied to the 2022 decoupling deferred balances for Residential Natural Gas service or for Non-Residential Natural Gas service.

Table 1-56. 2022 Natural Gas Earnings Test

	2022 Commission Basis Earnings Test for Decoupling		
Line No.			Natural Gas
1	Rate Base		$ 497,381,000
2	Net Income		$ 31,582,000
3	Calculated ROR		6.35%
4	Base ROR	Pro-rated	7.03%
5	Excess ROR		-0.68%
6	Excess Earnings		$ -
7	Conversion Factor		0.755463
8	Excess Revenue (Excess Earnings/CF)		$ -
9	Sharing %		50%
10	2022 Total Earnings Test Sharing		**$ -**

Three-Percent Annual Rate Increase Limitation 2022

Decoupling annual rate adjustment surcharges are subject to a 3% annual rate increase limitation (there is no reciprocal limit on rebate rate adjustments). The test is to divide the *incremental* annual revenue to be collected (proposed surcharge revenue minus present surcharge revenue) by the total "normalized" revenue for the two Rate Groups for the most recent January through December.

Normalized revenue is determined by multiplying the weather-corrected usage for the period by the present rates in effect. If the incremental amount of the proposed surcharge exceeds 3%, only a 3% incremental rate increase will apply. Any remaining deferred revenue will be carried over to the following years, in this instance to 2024.

Schedule 75E – Electric 3% Rate Increase Test

The Electric Incremental Surcharge Test is shown in Table 1-57. Specifications for the test limit the surcharge to 3%, with any remainder deferred to the following year. For both Residential customers and Non-Residential customers, the result for the Incremental Decoupling Recovery Rate is negative (Line 7), so there is no Carryover Deferred Revenue.

Table 1-57: 2022 Electric 3% Annual Rate Increase Limitation.

Line No.	**3% Incremental Surcharge Test**	Residential	Non-Residential
1	Revenue From 2021 Normalized Loads and Customers at Present Billing Rates (Note 1)	$ 268,876,060	$ 230,393,192
2	August 2022 - July 2023 Usage (kWhs)	2,571,886,722	2,146,299,272
3	Proposed Decoupling Recovery Rates	-$0.00725	-$0.00088
4	Present Decoupling Surcharge Recovery Rates	-$0.00234	$0.00132
5	Incremental Decoupling Recovery Rates	-$0.00491	-$0.00220
6	Incremental Decoupling Recovery	$ (12,627,964)	$ (4,721,858)
7	Incremental Surcharge %	**-4.70%**	**-2.05%**
8	3% Test Adjustment (Note 2)	$ -	$ -
9	3% Test Rate Adjustment	$0.00000	$0.00000
10	Adjusted Proposed Decoupling Recovery Rates	-$0.00725	-$0.00088
11	Adjusted Incremental Decoupling Recovery	$ (12,627,964)	$ (4,721,858)
12	Adjusted Incremental Surcharge %	**-4.70%**	**-2.05%**
	Notes		
	(1) Revenue from 2022 normalized loads and customers at present billing rates effective since December 21, 2022.		
	(2) The carryover balances will differ from the 3% adjustment amounts due to the revenue related expense gross up partially offset by additional interest on the outstanding balance during the amortization period.		

Schedule 175E – Natural Gas 3% Rate Increase Test

The Natural Gas Incremental Surcharge Test is shown in Table 1-58 The test limits the Residential and the Non-Residential Surcharge each to 3%. For the Residential Group, the Incremental Surcharge Percent (Line 7) is negative, so there is no Carryover Deferred Revenue (Line 8). For the Non-Residential Group, the incremental surcharge is below 3% (Line 7), so there is no Carryover Deferred Revenue amount (Line 8) to be to be deferred to the following year.

Table 1-58. 2022 Natural Gas 3% Rate Increase Limitation.

Line No.	**3% Incremental Surcharge Test**	Residential	Non-Residential
1	Revenue From 2022 Normalized Loads and Customers at Present Billing Rates (Note 1)	$ 184,901,129	$ 58,976,140
2	August 2023 - July 2024 Usage	136,584,128	61,178,736
3	Proposed Decoupling Recovery Rates	$0.00587	$0.03987
4	Present Decoupling Surcharge Recovery Rates (2)	$0.03899	$0.02866
5	Incremental Decoupling Recovery Rates	-$0.03312	$0.01121
6	Incremental Decoupling Recovery	$ (4,523,666)	$ 685,814
7	Incremental Surcharge %	**-2.45%**	**1.16%**
8	3% Test Adjustment (3)	$ -	$ -
9	3% Test Rate Adjustment	$0.00000	$0.00000
10	Adjusted Proposed Decoupling Recovery Rates	$0.00587	$0.03987
11	Adjusted Incremental Decoupling Recovery	$ (4,523,666)	$ 685,814
12	Adjusted Incremental Surcharge %	**-2.45%**	**1.16%**
	Notes		
	(1) Revenue from 2022 normalized loads and customers at present billing rates effective since November , 2023.		
	(3) The carryover balances will differ from the 3% adjustment amounts due to the revenue related expense gross up partially offset by additional interest on the outstanding balance during the amortization period.		

Audit Statements: Is the Source Data Credible?

Having reviewed calculations for conformance to Schedule 75 and Schedule 175, the second step in the Task 1 analysis is to validate the general credibility of the test period costs and revenues, balance sheets, load projections, and other company financial data. Since this data was audited by a professional audit team (Deloitte & Touche LLP) that provides an opinion regarding the accuracy of the data, we are relying on their professional opinion to validate the financial integrity of the data.

The Reports of the Independent Registered Public Accounting Firm for the Avista Corporation and subsidiaries for calendar years 2020,[73] 2021,[74] and 2022,[75] based on certified audits of the company's accounting practices are shown in Figures 1-2, 1-3, and 1-4, respectively. Each Independent Registered Public Accounting Report expresses an unqualified opinion on the Company's internal control over financial reporting. These opinions validate the data used to implement the Avista electric and natural gas decoupling mechanisms.

The Deloitte & Touche LLP "Report of Independent Registered Public Accounting Firm" for the twelve-month period ending December 31, 2020, is shown as Figure 1-2. The audit statements for 2021 and 2022 are shown in Figure 1-3 and 1-4.

[73] Avista Energy, US Securities and Exchange Commission, Form 10K, February 23, 2021, P. 138.
[74] Avista Energy, US Securities and Exchange Commission, Form 10K, February 22, 2022, P. 137.
[75] Avista Energy, US Securities and Exchange Commission, Form 10K, February 23, 2023, P. 137.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING

FIRM To the shareholders and the Board of Directors of Avista Corporation

Opinion on Internal Control over Financial Reporting

We have audited the internal control over financial reporting of Avista Corporation and subsidiaries (the "Company") as of December 31, 2020, 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, 2020, 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, 2020, of the Company and our report dated February 23, 2021, expressed an unqualified opinion on those financial statements.

Basis for Opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying *Management's Report on Internal Control Over Financial Reporting*. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ Deloitte & Touche LLP
Portland, Oregon
February 23, 2021

Figure 1-2. Financial Audit Opinion for Calendar 2020

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING

FIRM To the shareholders and the Board of Directors of Avista

Corporation **Opinion on Internal Control over Financial Reporting**

We have audited the internal control over financial reporting of Avista Corporation and subsidiaries (the "Company") as of December 31, 2021, 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, 2021, 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, 2021, of the Company and our report dated February 22, 2022, expressed an unqualified opinion on those financial statements.

Basis for Opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ Deloitte & Touche LLP

Portland, Oregon
February 22, 2022

Figure 1-3. Financial Audit Opinion for Calendar 2021.

REPORT OF INDEPENDENT REGISTERED

PUBLIC ACCOUNTING FIRM To the

shareholders and the Board of Directors of Avista

Corporation **Opinion on Internal Control over**

Financial Reporting

We have audited the internal control over financial reporting of Avista Corporation 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 21, 2023, expressed an unqualified opinion on those financial statements.

Basis for Opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ Deloitte & Touche LLP

Portland, Oregon
February 21, 2023

Figure 1-4. Financial Audit Opinion for Calendar 2022.

Summary - Fidelity

Based on our analysis of three years of data, we conclude that Avista has calculated rates and deferrals for the first through the third Decoupling Years in accordance with the Commission Order approving the decoupling mechanisms.

The purpose of the Decoupling Mechanism is to decouple the Company's Commission-authorized revenues from sales, such that the *portion of the Company's fixed costs planned for recovery through volumetric sales and not otherwise recovered from actual energy sales* will be recovered through the mechanism. In decoupling, the revenue requirement for a given year is first set. The portion of fixed costs collected through the fixed portion of customer bills is not included in the analysis. Since volumetric sales fluctuate and may not fully cover the fixed cost component included within the volumetric portions of customer rates, the difference between actual decoupling-related revenue received from customers through volumetric rates, and the decoupling-related revenue approved for recovery through volumetric rates is accumulated in deferred revenue accounts.

Operationally, this compliance verification was carried out in two steps:

- First, we traced calculations to insure conformance with Schedule 75(A, B, C, D, E) and Schedule 175(A, B, C, D, E). In carrying out this analysis, we checked to see that the reported calculations matched the methodological specifications in each Schedule. Also, we checked for 2020, 2021 and 2022 the component Excel spreadsheets introduced as Avista Exhibits for the annual filings for Tariff WN U-28 Electric Service for Electric Decoupling Rate Adjustment; and for Tariff WN U-29 Natural Gas Service for Natural Gas Decoupling Rate Adjustment for each of the three years examined.
- Second, we have included the opinions of the independent auditor for 2020, 2021 and 2022 to indicate the validity of the financial data upon which the calculations depend.

The overall result in this section of the analysis is that we find the deferrals and rates to have been calculated by the Company in accordance with the Commission guidance as operationalized by the methodological specification in Schedule 75 and Schedule 175.

Section 2. Revenue Effects and Billing Impacts

In this section we present the findings of analysis designed to address evaluation objectives and tasks related to an assessment of customer billing and revenue impacts.

The discussion in this section and throughout this report use the customer classes (rate categories) customarily used by Avista for decoupling filings. These customer classes are listed in Table 2-1 below for electric and natural gas customers.[76]

Table 2-1: Electric and Gas Rate Groups and Customer Classes (Rate Categories).

Electric Service					Natural Gas Service				
Rate Group	Customer Class Code	Customer Class	Rate Schedules	Decoupled	Rate Group	Customer Class Code	Customer Class	Rate Schedules	Decoupled
Residential	E1	Residential	1, 2	Yes	Residential	G1	Residential	101, 102	Yes
Non-Residential	E2A	General Services	11, 12, 13	Yes	Non-Residential	G2A	General Services	111	Yes
Non-Residential	E2B	Large General Services	21, 22, 23	Yes	Non-Residential	G2B	Large General Services	112, 121, 122	Yes
Non-Residential	E2C	Pumping	30, 31, 32	Yes	Non-Residential	G2C	Interruptible	131	Yes
Non-Decoupled	E3A	Extra Large General Services	25	No	Non-Decoupled	G3A	Excluded Schedules1	132	No
Non-Decoupled	E3B	Street & Area Lighting	41 - 48	No	Non-Decoupled	G3B	Excluded Schedules 2	146, 148	No

For reporting and referencing purposes, we have defined a Customer Class Code for each rate category. The Customer Class Code identifies the fuel in the first character, electric (E) or natural gas (G), decoupling rate group in the second and a subset of the rate group defined by one or more rate schedules in the third. Separately for electric and natural gas, and as explained in the section of the evaluation covering Task 1, the decoupling mechanism defines two groups of customers subject to the decoupling tracker adjustment, residential (Rate Group 1) and non-residential (Rate Group 2). We also define Rate Group 3, non-residential customers not subject to the decoupling tariff. The aggregation level hierarchy listed from highest level of aggregation to the lowest is as follows:

1. Rate Group
2. Customer Class (Rate Category)
3. Rate Schedule

[76] Electric rate schedules 13 and 23, optional electric vehicle rate for general service and large general service customers, respectively, were added in 2021. Natural gas service experienced the following changes over the evaluation period: rate schedule 112 was decoupled in 2018 and rate schedules 121 and 122 were discontinued in 2020. There have been no customers on rate schedule 131 since 2012, the first year of history reviewed in the first decoupling evaluation.

For example, Customer Class Code E1 is electric decoupling Rate Group 1, the residential customer class, and includes rate schedules 1 and 2. A third character is not necessary since Rate Group 1 only includes residential rate schedules. Rate Group 2 is non-residential customers subject to the decoupling adjustment tariff. There are three customer classes (collection of rate schedules) included in Rate Group 2 for both electric and natural gas service. Rate Group 3 is used to identify customers not subject to the decoupling tariff adjustment. Electric and natural gas each have two customer classes that belong to Rate Group 3.

Summary of Decoupling Mechanics and Results

Before examining the impact of decoupling by rate class it is useful to take a high-level look at the mechanics of the decoupling mechanism, actual deferrals, requested recovery amounts and decoupling rates. Avista's decoupling mechanism allows for the recovery of the difference between actual revenue and allowed revenue.[77] This difference is referred to as the decoupling deferral balance and is tracked for the two electric and two natural gas rate groups subject to decoupling; residential and non-residential.

Beginning in 2015, monthly deferrals are accumulated over a calendar year and used with other determinants to calculate the decoupling rate required to collect or refund the under or over collected revenue. Decoupling rates become effective in Schedule 75 (electric) and Schedule 175 (natural gas) August 1st of the year following the year in which deferral balances were calculated.[78] The timing of deferral balance accumulation and decoupling rate adjustments is shown in Table 2-2.

Table 2-2 Avista Decoupling Deferral Year and Decoupling Rate Year Definitions.

Decoupling Year	Deferral Balance Accumulation (Calendar Year)	Decoupling Rates Effective
1	2015	Nov 1, 2016 – Oct 31, 2017
2	2016	Nov 1, 2017 – Oct 31, 2018
3	2017	Nov 1, 2018 – Oct 31, 2019
4	2018	Nov 1, 2019 – Jul 31, 2020
5	2019	Aug 1, 2020 – Jul 31, 2021
6	2020	Aug 1, 2021 – Jul 31, 2022
7	2021	Aug 1, 2022 – Jul 31, 2023
8	2022	Aug 1, 2023 – Jul 31, 2024

The first deferral year resulted in a deferral balance at the end of 2015 that was used, along with other determinants, to calculate the decoupling rate in effect during the first rate year (November 1, 2016, through October 31, 2017). The same process is followed

[77] The details of Avista's decoupling mechanism are included in Final Order ("Order 5") for Docket Numbers UE-140188 and UG-140189.
[78] The date which the decoupling rider becomes effective in rates was changed from November 1st to August 1st in 2020 (Final Order 09, Dockets UE-190334, UG-190335, and UE-190222 (Consolidated)). This change was made to coincide with other annual rate adjustments to minimize rate changes experienced by Avista customers and to aid Avista in the timely recovery of deferred revenue.

in the second deferral year and rate year. Any deferral balance carried over from a prior year due to the application of the 3% cap is included in the calculations of decoupling rates in effect during the next rate year.

A summary of decoupling deferral results and decoupling tracker rates is shown in Table 2-3 for last five decoupling years, 2018-2022.

Years shown in Table 2-3 correspond to the deferral years and rate years shown in Table 2-2. For example, the 2019 column refers to calculations made from data for deferral year five (2019) and the resulting decoupling rate in effect from August 1, 2020, through July 31, 2021. The "Summary of Deferred Revenue" sections of the table show key results for each decoupling year including the deferral balance for the year, customer surcharge (rebate) revenue, and any carryover due to the rate increase cap. The "Summary of Decoupling Rate Adjustment" sections of the table present key results related to the decoupling adjustment rate including the results of the earnings test, whether or not the 3% cap on rates was reached and the resulting decoupling rate per unit of energy.

As a specific example, consider the workings of the decoupling mechanism as shown for the natural gas residential rate group in 2022. Cumulative deferral balances during the 2022 calendar year amounted to a negative $1.069 million. The negative deferral balance would, considered in isolation, suggest a customer rebate through a negative decoupling rate (Schedule 175). However, the prior year decoupling rate adjustment was limited by the 3% cap, resulting in a $1.643 million carryover from 2021 to 2022. This carryover along with adjustments, combined with the negative deferral in 2022, resulting in a customer surcharge of $0.802 million. Although positive, the surcharge was significantly lower than the $5.379 million surcharge requested from 2021 results. Consequently, the decoupling rate (Schedule 175) fell from 3.899 to 0.587 cents per therm for the residential rate group, effective August 1, 2023. The rate adjustment was not impacted by either the earning test or the 3% cap, both of which are examined in greater detail later in this section.

An important characteristic of the Avista decoupling mechanism is the ability of the mechanism to clear deferral balances even with a rate cap and even in the face of unusual circumstances, such as, persistently warmer than normal winters over consecutive years. Because the 3% test is applied using current rates, including the current decoupling rate, the new decoupling rate will adjust higher and be capable of amortizing higher levels of requested recovery.[79] At some point, even if weather or other conditions that caused initially high deferral carryovers persist, the decoupling rate will eventually adjust to a level that recovers 100 percent of requested recovery and carryover deferral balances will fall to zero. *This greatly reduces the possibility of snow-balling deferral balances even in the face of persistently warm winters over consecutive heating seasons.*

[79] This is a feature of the Avista decoupling mechanism that makes the mechanism flexible.

Table 2-3. Summary Deferral Balances and Decoupling Recovery Rate - Electric.

---------------------------------- Electric ----------------------------------											
		Residential Group					**Non-Residential Group**				
	Notes	**2018**	**2019**	**2020**	**2021**	**2022**	**2018**	**2019**	**2020**	**2021**	**2022**
Summary of Deferred Revenue (1,000 $)											
Deferred revenue		8,620	1,182	(811)	(5,124)	(16,126)	7,052	6,860	11,263	2,389	385
Requested recovery	A	9,571	5,904	(1,112)	(5,801)	(18,646)	7,956	9,830	14,761	2,748	(1,889)
Customer surcharge (rebate) revenue		6,627	5,904	(1,112)	(5,801)	(18,646)	7,890	7,878	14,489	2,748	(1,889)
Carryover deferred revenue		2,943	0	0	0	0	65	1,952	271	0	0
Summary of Decoupling Rate Adjustment											
Earnings Test Results (Over/Under)	B	Under	Under	Under	Under	Under	Under	Under	Under	Under	Under
Decoupling rate (schedule 75) (cents/kWh)	C	0.279	0.244	(0.045)	(0.234)	(0.725)	0.365	0.365	0.679	0.132	(0.088)
Incremental revenue (percent)		4.3%	-0.4%	-3.0%	-2.0%	-4.7%	3.0%	0.0%	3.0%	-4.9%	-2.0%
Limited by 3% cap?	D	Yes	No	No	No	No	Yes	No	Yes	No	No
Notes											
A: Requested recovery is equal to deferred revenue after adjusting for shared excess earnings (if applicable), deferral balance carryover from prior year (if any), interest, and revenue related expenses.											
B: Indicates whether or not earnings were over or under Avista's allowed return. When earnings exceed Avista's allowed return, half of excess earnings are shared with customers through the decoupling rate adjustment.											
C: Decoupling rates Schedule 75 (electric) and Schedule 175 (natural gas) take effect on November 1st, 2019, for 2018 results and August 1st of the following year for 2019-2022 results.											
D: As a response to the COVID 19 pandemic, Avista proposed replacing the 3% cap with a 0% cap on the decoupling rate adjustment effective August 1st, 2020, shown in the 2019 column of this table. This change only applied to 2019 results and only impacted the electric non-residential rate group as this group was the only one that would have resulted in an increase in rates.											

Table 2-4: Summary of Deferral Balances and Decoupling Recovery Rate - Natural Gas.

---------------------------------- Natural Gas ----------------------------------											
		Residential Group					**Non-Residential Group**				
	Notes	**2018**	**2019**	**2020**	**2021**	**2022**	**2018**	**2019**	**2020**	**2021**	**2022**
Summary of Deferred Revenue (1,000 $):											
Deferred revenue		741	(1,054)	1,174	6,559	(1,069)	984	63	445	2,401	1,302
Requested recovery	A	556	(896)	1,256	7,021	802	1,075	253	495	2,574	2,439
Customer surcharge (rebate) revenue		556	(896)	1,256	5,379	802	1,075	253	495	1,680	2,439
Carryover deferred revenue		0	0	0	1,643	0	0	0	0	894	0
Summary of Decoupling Rate Adjustment:											
Earnings Test Results (Over/Under)	B	Over	Under	Under	Under	Under	Over	Under	Under	Under	Under
Decoupling rate (schedule 175) (cents/therm)	C	0.420	(0.685)	0.925	3.899	0.587	1.841	0.419	0.813	2.866	3.987
Incremental revenue (percent)		4.2%	-1.2%	1.8%	3.0%	-2.5%	2.2%	-2.2%	0.7%	3.0%	1.2%
Limited by 3% cap?	D	No	No	No	Yes	No	No	No	No	Yes	No
Notes											
A: Requested recovery is equal to deferred revenue after adjusting for shared excess earnings (if applicable), deferral balance carryover from prior year (if any), interest, and revenue related expenses.											
B: Indicates whether or not earnings were over or under Avista's allowed return. When earnings exceed Avista's allowed return, half of excess earnings are shared with customers through the decoupling rate adjustment.											
C: Decoupling rates Schedule 75 (electric) and Schedule 175 (natural gas) take effect on November 1st, 2019, for 2018 results and August 1st of the following year for 2019-2022 results.											
D: As a response to the COVID 19 pandemic, Avista proposed replacing the 3% cap with a 0% cap on the decoupling rate adjustment effective August 1st, 2020, shown in the 2019 column of this table. This change only applied to 2019 results and only impacted the electric non-residential rate group as this group was the only one that would have resulted in an increase in rates.											

Earnings Test and Rate Cap

The question as stated in the RFP is:

"Please provide analysis and trends on whether the rate cap was reached and the results of the earnings test?"

The earnings test in Avista's decoupling mechanism incorporates a method of sharing excess earnings, if any, in a decoupling year between rate payers and share owners. When Avista's rate of return exceeds the Commission approved rate of return, one-half of the revenue over and above the allowed rate of return is shared with customers. Excess revenue shared with customers is split between the residential and non-residential customer groups based on the percentage of total revenue from each group. Excess earnings, when present, have the effect of reducing the requested recovery for the decoupling year.

The results of the annual earnings test are shown in Table 2-3 in the row labeled "Earnings Test Results". A value of "Over" is used to indicate when earnings exceeded the allowed rate of return and "Under" is used when earnings were lower than allowed. As shown in Table 2-3, Avista's rate of return for electric distribution did not exceed the allowed rate of return over the 2018 through 2022 decoupling years. There were excess earnings for natural gas distribution in 2018 which served to reduce the requested decoupling recovery for both rate groups.

Avista's decoupling mechanism includes a provision that limits annual decoupling rate adjustment surcharges to no more than a 3% increase. After excess earnings resulting from application of the earnings test are applied, if any, the requested recovery is subjected to a 3% cap. The cap only applies to surcharges, not rebates, and only to the portion of the surcharge above zero. Decoupling rate declines are not limited by the cap.

Results of the 3% cap are shown in Table 2-3 in the row labeled "Limited by 3% Cap?". A value of Yes means that a portion of the requested recovery was withheld and rolled over to the following year so that the resulting increase in the decoupling rate does not exceed 3%. The decoupling surcharge for residential electric customers was limited by the 3% cap once (2018) over decoupling years 2018 through 2022. The cap limited the surcharge for non-residential electric customers in 2018 and 2020. The only time the 3% cap limited decoupling surcharges for natural gas customers over the 2018 to 2022 period was in 2021 for both the residential and non-residential rate groups.

A one-time adjustment to the cap was used for 2019 so that the decoupling surcharge would not be increased for either customer group, essentially a rate cap of zero percent. The 2019 surcharge had an effective date of August 1, 2020, a time when the impacts of the pandemic were especially hard hitting. Avista decided to not allow the 2019 decoupling surcharge to result in an increase in rates given the overall economic environment. Non-residential electric was the only customer group impacted by this one-time lowering of the cap to zero percent. The decoupling rate declined for all other customer groups that year, resulting in a rate drop from decoupling effective August 1, 2020.

Analysis of Customer Billing Impacts

In this section we examine the following evaluation question:

"Were there any differences in Decoupling tracker adjustments between rate classes?"

Annual data from 2018 through 2022 for customer counts, usage, revenue, and revenue from the decoupling rate (Schedule 75 for electric and Schedule 175 for natural gas) are examined. The data reviewed in this section are calendarized actual values and have not been normalized for weather. We begin our analysis and reporting with electric customer classes followed by natural gas customer classes.

Electric

Avista serves nearly 270 thousand electric customers in the state of Washington. All but about 500 of these customers are subject to the decoupling tracker adjustment. Annual data for the residential customer class is shown in Table 2-5. The residential customer class is Avista's largest electric customer class by customers, volumes delivered (MWh) and revenue.

Table 2-5. Annual Electric Data - Residential Customer Class (Schedules 1&2).

	Annual Totals				Per Customer			
Year	**Customers**	**Usage (MWh)**	**Revenue (Millions $)**	**Schedule 75 Revenue (Millions $)**	**Usage kWh**	**Revenue**	**Schedule 75**	**Pct of Bill**
2018	215,665	2,366,635	$228.7	$8.7	10,974	$1,061	$40.46	3.8%
2019	218,293	2,436,265	$227.3	-$1.5	11,161	$1,041	-$6.70	-0.6%
2020	221,160	2,435,082	$229.7	$6.5	11,010	$1,039	$29.28	2.8%
2021	224,169	2,545,508	$241.7	$3.7	11,355	$1,078	$16.37	1.5%
2022	226,868	2,638,378	$250.5	-$2.3	11,630	$1,104	-$10.08	-0.9%

Avista serves just over a quarter of a million residential electric customers, averaging between 11,000 and 12,000 kWh usage per year. Since 2018, the revenue per residential customer has averaged between $1,000 and $1,110. Revenue from Schedule 75, the decoupling tracker, has fluctuated annually between a rebate of $10.08 to an average surcharge of $40.46. This equates to a range of -0.9% to 3.8% as a percentage of the annual electric bill.

Annual data for General Service customers are shown in Table 2-6.

Table 2-6. Annual Electric Data - General Services (Rate Schedules 11, 12, and 13).

	Annual Totals				Per Customer			
Year	**Customers**	**Usage (MWh)**	**Revenue (Millions $)**	**Schedule 75 (Millions $)**	**Usage kWh**	**Revenue**	**Schedule 75**	**Pct of Bill**
2018	32,233	622,703	$78.5	$0.3	19,319	$2,435	$8	0.3%
2019	32,650	627,094	$80.4	$0.6	19,207	$2,462	$18	0.7%
2020	33,177	595,000	$77.8	$2.2	17,934	$2,344	$66	2.8%
2021	33,746	650,970	$85.6	$3.1	19,290	$2,536	$93	3.7%
2022	34,287	686,667	$91.8	$3.9	20,027	$2,677	$113	4.2%

Avista serves about 34 thousand general service electric customers. Average customer usage has ranged from just under 18,000 kWh to just over 20,000 kWh. Annual customer bills have averaged around $2,500. Schedule 75 revenue has increased from $8 to $113 per custom since 2018. As a percentage of the average customer bill, Schedule 75 has increased from 0.3% in 2018 to 4.2% in 2022. The pattern of increasing Schedule 75 charges is common in the non-residential electric customer classes and is examined closer later in this section.

Annual data for Large General Services customers are shown in Table 2-7.

Table 2-7. Annual Electric Data - Large General Services (Rate Schedules 21, 22, and 23).

	Annual Totals				Per Customer			
Year	**Customers**	**Usage (MWh)**	**Revenue (Millions $)**	**Schedule 75 (Millions $)**	**Usage kWh**	**Revenue**	**Schedule 75**	**Pct of Bill**
2018	1,899	1,380,340	$131.6	$0.6	726,909	$69,282	$303	0.4%
2019	1,912	1,376,029	$133.8	$1.3	719,775	$69,995	$661	0.9%
2020	1,885	1,273,220	$128.2	$4.6	675,568	$68,048	$2,465	3.6%
2021	1,805	1,320,096	$135.6	$6.3	731,321	$75,124	$3,517	4.7%
2022	1,711	1,325,181	$139.5	$7.5	774,657	$81,546	$4,377	5.4%

Large general service customers number less than two thousand and account for between $130 to $140 million annually since 2018. Customers in this class are the largest of the decoupled customer classes, averaging about three-quarters of a million kWh per year with an average annual bill between $70,000 and $80,000. Like general service customers, this customer class has seen rising Schedule 75 bills in absolute and as a percentage of bill basis since 2018.

Annual data for pumping customers are shown in Table 2-7. The pumping customer class is comprised mostly of municipal and agricultural pumping applications such as water treatment and irrigation.

Table 2-7. Annual Electric Data –Pumping (Rate Schedules 30, 31, and 32)

	Annual Totals				Per Customer			
Year	**Customers**	**Usage (MWh)**	**Revenue (Millions $)**	**Schedule 75 (Millions $)**	**Usage kWh**	**Revenue**	**Schedule 75**	**Pct of Bill**
2018	2,454	145,808	$12.5	$0.1	59,420	$5,095	$24	0.5%
2019	2,458	139,560	$12.2	$0.1	56,786	$4,980	$38	0.8%
2020	2,488	144,620	$13.0	$0.5	58,131	$5,218	$214	4.1%
2021	2,527	161,841	$14.8	$0.8	64,051	$5,868	$306	5.2%
2022	2,533	139,673	$13.5	$0.9	55,147	$5,316	$338	6.4%

About 2,500 customers are served in Avista’s pumping customer class, contributing between $12 million and $15 million annually since 2018. Pumping customers used an average of 55,000 to 64,000 kWh per year between 2018 and 2022. Schedule 75 revenue has increased over the 2018-2022 period to over 6% of the average customer bill in 2022. This increasing pattern is examined further below.

To visualize and contrast the impacts on customer electric revenues between customer classes, the percentage of electric revenues attributed to Schedule 75 over the 2018 to 2022 period is shown in Figure 2-1.

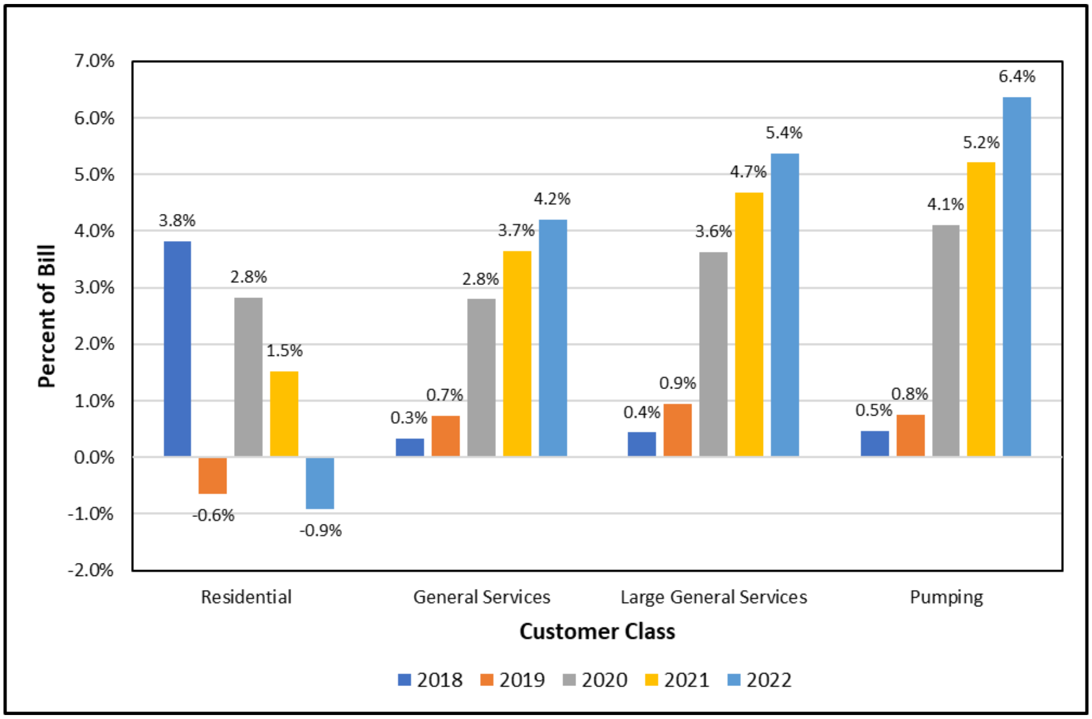

Figure 2-1: Annual Schedule 75 Revenue as a Percent of Customer Class Revenues.

Figure 2-1 shows annual Schedule 75 revenue as a percentage of total revenue for each customer class subject to decoupling. When observing the impact of decoupling on rates and revenues it is useful to consider that because decoupling rate becomes effective August 1st of the year following the decoupling year, decoupling credits and surcharges are observed with a lag.[80] For example, 2020 decoupling results are observed in rates for five calendar months of 2021 (August through December) and seven calendar months of 2022 (January through July). The greater number of months in year two after the decoupling year along with the typically larger weather impacts in January through July compared to August through December means that the results from a decoupling year are observed in customer rates and revenues in the first and second calendar year following the decoupling year and the largest impact is in the second year.

The residential rate group is comprised of only one customer class, residential. From 2018 through 2022, Schedule 75 revenue as a percent of annual residential customer bills varied between a negative 0.9 percent to 3.8 percent. Unlike the non-residential customer classes, there appears to be a trend over this timeframe with decoupling accounting for a declining percentage of the annual residential bill. Annual use and revenue per customer have been trending higher since 2020, which would impact pattern shown in Figure 2-1

[80] Prior to the fifth decoupling year (2019), decoupling results became effective in rates on November 1st of the following year. See Table 2-2 for a complete history of deferral years and the dates decoupling rates became effective.

with a lag. An analysis of factors contributing to variation in usage and revenue per customer is presented later in this report.

The non-residential rate group is comprised of three decoupled non-residential customer classes. These non-residential customer classes are shown in Figure 2-1. For the non-residential customer classes, Schedule 75 had the impact of increasing customer bills in every calendar year between 2018-2022. A couple of patterns are evident in the data shown in Figure 2-1. In each of the three non-residential customer classes, decoupling charges as a percentage of the bill is increasing over the 2018 through 2022 period. Also, there appears to be a difference in the level of percentage impact between the classes with the large general services class showing higher percentages than the general services class and the pumping class larger than the large general services class. These differences between the customer classes are simply noted for now. Possible reasons will be explored later in the report.

Natural Gas

Avista serves approximately 175,000 natural gas customers in the state of Washington. All but about fifty of these customers are subject to the decoupling tracker adjustment. Annual data from 2018 through 2022 for residential customers are shown in Table 2-8. The residential customer class is Avista's largest natural gas customer class by customers, volumes delivered (therms) and revenue.

Table 2-8. Annual Natural Gas Data – Residential (Rate Schedules 101 & 102).

	Annual Totals				Per Customer			
Year	**Customers**	**Usage (1,000 Therms)**	**Revenue (Millions $)**	**Schedule 175 Revenue ($)**	**Usage Therms**	**Revenue**	**Schedule 175 Revenue**	**Pct of Bill**
2018	161,791	123,968	$105.3	$4,947,487	766	$651	$30.58	4.7%
2019	165,362	137,563	$106.0	-$2,909,847	832	$641	-$17.60	-2.7%
2020	168,189	125,794	$112.0	$76,322	748	$666	$0.45	0.1%
2021	170,582	125,317	$116.8	-$243,034	735	$685	-$1.42	-0.2%
2022	172,357	141,758	$154.2	$2,484,396	822	$895	$14.41	1.6%

Avista serves over 170 thousand residential natural gas customers, with average annual usage per customer ranging between 735 and 832 therms since 2018. Since 2018, the revenue per residential customer has averaged between $641 and $895. Revenue from Schedule 175, the decoupling tracker, has fluctuated annually between a rebate of $17.60 to a surcharge of $30.58 per customer. This equates to a range of -2.7% to 4.7% as a percentage of the annual natural gas bill.

Annual data for General Service customers are shown in Table 2-9.

Table 2-9. Annual Natural Gas Data – General Services (Rate Schedule 111).

	Annual Totals				Per Customer			
Year	Customers	Usage (1,000 Therms)	Revenue (Millions $)	Schedule 175 Revenue ($)	Usage Therms	Revenue	Schedule 175 Revenue	Pct of Bill
2018	3,102	57,162	$34.0	$1,820,085	18,430	$10,958	$587	5.4%
2019	3,098	58,877	$32.6	$526,664	19,003	$10,516	$170	1.6%
2020	3,145	52,359	$33.3	$712,032	16,650	$10,578	$226	2.1%
2021	3,195	54,507	$35.6	$298,952	17,061	$11,148	$94	0.8%
2022	3,345	63,585	$51.3	$864,335	19,008	$15,324	$258	1.7%

Avista serves over three thousand general service natural gas customers. Average customer usage has ranged from a low of 16,650 therms during 2020, the year most impacted by the pandemic, to just over 19,000 therms in 2019 and 2022. Annual average customer bills have ranged between about $10,500 to $15,300 and Schedule 175 revenue has ranged from $94 to $587 per custom since 2018. As a percentage of the average customer bill, Schedule 175 has ranged from 0.8% in 2021 to 5.4% in 2018.

Annual data for Large General Services customers are shown in Table 2-10.

Table 2-10. Annual Natural Gas Data - Large Gen. Services (Schedules 112, 121, and 122).

	Annual Totals				Per Customer			
Year	Customers	Usage (1,000 Therms)	Revenue (Millions $)	Schedule 175 Revenue ($)	Usage Therms	Revenue	Schedule 175 Revenue	Pct of Bill
2018	-29	-2,756	-$2.1	-$15,102	96,705	$75,232	$530	0.7%
2019	5	2,852	$1.4	$23,530	526,580	$249,496	$4,344	1.7%
2020	5	3,206	$1.5	$54,639	712,393	$344,207	$12,142	3.5%
2021	3	687	$0.4	$3,333	265,956	$141,722	$1,290	0.9%
2022	1	164	$0.1	$3,926	245,809	$185,308	$5,889	3.2%

There are only a few large general service natural gas customers and, excluding accounting system adjustments in 2018, the customer count has fallen from five in 2019 and 2020 to only one customer in 2022. Per customer usage has varied widely, averaging around a quarter million therms over the last two years. As a percentage of the average customer bill, Schedule 175 has ranged from 0.9% in 2021 to 3.5% in 2020.

There were no interruptible natural gas customers, Schedule 131, over the 2018 to 2022 period.

To visualize and contrast the impacts on natural gas revenues between customer classes, the percentage of natural gas revenues attributed to Schedule 175 over the 2018 to 2022 period is shown in Figure 2-2.

Figure 2-2: Annual Schedule 175 Revenue as a Percent of Customer Class Revenues.

Figure 2-2 shows annual Schedule 175 revenue as a percentage of total revenue for each customer class subject to decoupling. As previously discussed, when observing the impact of decoupling on rates and revenues it is useful to consider that because decoupling rate becomes effective August 1st of the year following the decoupling year, decoupling credits and surcharges are observed with a lag.[81] For example, 2020 decoupling results are observed in rates for five calendar months of 2021 (August through December) and seven calendar months of 2022 (January through July). The greater number of months in year two after the decoupling year along with the typically larger weather impacts in January through July compared to August through December means that the results from a decoupling year are observed in customer rates and revenues in the first and second calendar year following the decoupling year and the largest impact is typically in the second year.

The residential rate group is comprised of only one customer class, residential. From 2018 through 2022, Schedule 175 revenue as a percent of annual residential customer bills varied between a negative 2.7 percent to a positive 4.7 percent. There does not appear to be any discernable trend since 2018.

[81] Prior to the fifth decoupling year (2019), decoupling results became effective in rates on November 1st of the following year. See Table 2-2 for a complete history of deferral years and the dates decoupling rates became effective.

The non-residential rate group is comprised of three decoupled non-residential customer classes. The two non-residential customer classes with customer data to report are shown in Figure 2-2. For the non-residential customer classes, Schedule 175 had the impact of increasing customer bills in every calendar year between 2018-2022. Other than adding to customer bills in each calendar year since 2018, there does not appear to be any discernable trend in the non-residential data shown in Figure 2-2. Excluding 2018, the percentage that Schedule 175 charges make up of an average customers' bill appears to be somewhat higher in the large general services customer class over general services customers.

Analysis of Revenue Impacts

In this section we examine the effects of the decoupling mechanisms on Avista's revenue. The objective of Task 4, as stated in the request for proposal, is shown below:

> *"Analysis of the Mechanism's impact on Company revenues (i.e., whether there has been a stabilizing effect)."*

Relating to this objective are the following evaluation questions, also taken from the RFP:

> *"What impact did the Mechanisms have on the Company's revenues (i.e., whether there has been a stabilizing effect)?"*
>
> *What were the causes of the deviation of actual revenue-per-customer from authorized revenue-per-customer?"*
>
> *"What factors impacted the deferral and rate changes, and what was the magnitude of that impact? (e.g., weather, customer counts, conservation, economy, etc.)"*
>
> *"What was the impact of the Decoupling deferral on Avista's revenues and rates?"*
>
> *"What was the effect of updates to the decoupling baseline and resulting effects on deferrals under the mechanisms?"*

Our discussion in this section is organized by each of the evaluation questions listed above. Much of the data used to address these questions has been presented in earlier sections of this report and is repeated here for ease of discussion and the convenience of the reader.

Has Decoupling Stabilized Revenue

The question as stated in the RFP is:

> *"What impact did the Mechanisms have on the Avista's revenues (i.e., whether there has been a stabilizing effect)?"*

This is a straightforward question and easy to answer by comparing actual revenue with actual revenue plus deferred revenue. In order to answer this question, we calculated the annual variation in revenue over the 2020 to 2022 period with and without the revenue from decoupling deferrals. This time period includes the three primary years under evaluation and has the added advantage of encompassing the time period where the decoupling mechanism applied only to existing customers and includes only pandemic impacted years.[82] We used the coefficient of variation, calculated as the standard deviation divided by the mean, as our measure of variability.[83] Figure 2-3 shows the results of our calculations for electric revenue.

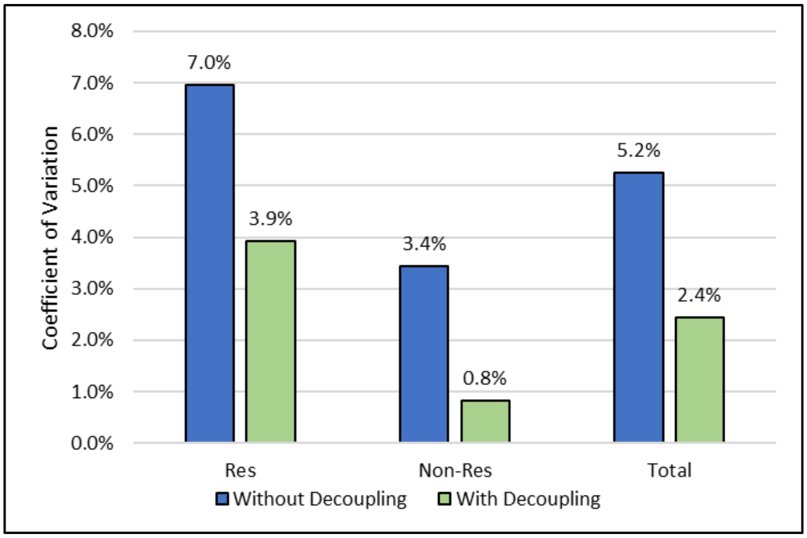

Figure 2-3: Electric Revenue Variability (2020-2022).

The bars labeled "Without Decoupling" refer to base rate revenue only and does not include deferred revenue through the decoupling mechanism. Bars labeled "With Decoupling" include base rate and decoupling deferral revenue. Results are shown for both decoupled rate groups and their total. It is clear from the results shown in Figure 2-3 that there has been a stabilizing effect on revenue as a result of decoupling. For residential and non-residential rate groups, variability is roughly 60% and 25%,

[82] New customers were excluded from the decoupling deferral calculations beginning with April 2020. The first state mandated shutdowns to combat the COVID-19 pandemic began in mid-March 2020. By April 2020, the U.S. unemployment rate shot to a high of 14.7% from 4.4% in March and 3.5% in February.
[83] The coefficient of variation shows the extent of variability in relation to the mean by dividing the standard deviation of a distribution by its mean, producing a measure of relative variation. It is used to compare the variability between groups. In finance it is used to indicate volatility or risk. Here it shows that variability is reduced with decoupling (the green bars in Figure 2-3 and Figure 2-4 are shorter than the blue bars).

respectively, of the level of variability without decoupling. For both rate groups combined, decoupling has reduced revenue variability by well over half.

Variation in natural gas revenue is shown in Figure 2-4.

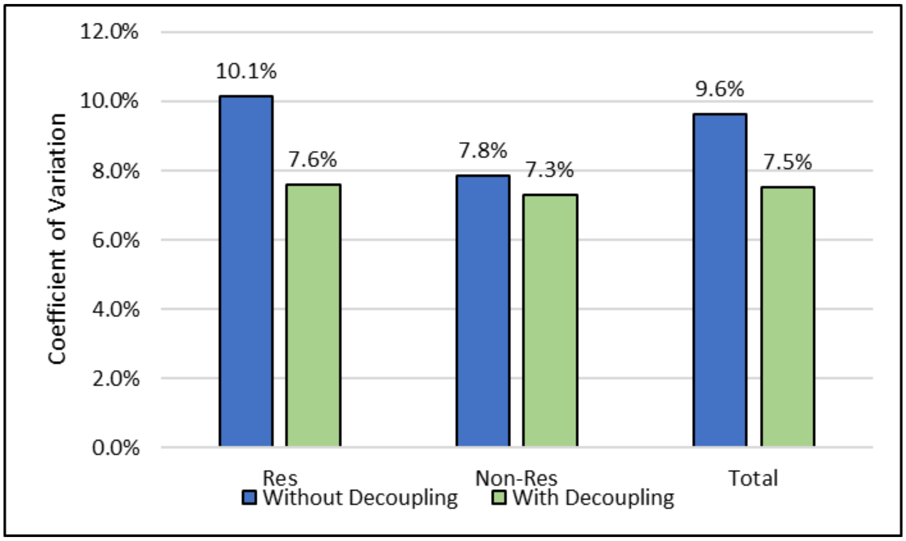

Figure 2-4: Natural Gas Revenue Variability (2020-2022).

For natural gas revenues, variability has also been reduced by decoupling but not to the extent as seen for decoupled electric rate groups. Revenue variability in natural gas residential is about 2.5 percentage points lower with decoupling. For non-residential customers, revenue variability has been reduced by about one half of a percentage point. For both rate groups combined, decoupling has reduced revenue variability in natural gas to about 80% of the level of variability without decoupling.[84]

Revenue Deviations from Planning Assumptions and Causes

Some of the revenue related evaluation questions have to do with the magnitude and causes for deviations from planning assumptions. These questions as stated in the RFP are:

> *"What were the causes of the deviation of actual revenue-per-customer from authorized revenue-per-customer?"*
>
> *"What factors impacted the deferral and rate changes, and what was the magnitude of that impact? (e.g., weather, customer counts, conservation, economy, etc.)"*

[84] The 2018 evaluation report, based on analysis of 2015-2017 revenues, found that decoupling reduced natural gas revenue variation by a greater degree than the findings in this evaluation (Avista Decoupling Evaluation, 2018, p 4-2). Although it should be pointed out that both evaluations are based on a relatively short three-year period.

Actual and authorized revenue-per-customer is shown for electric rate groups in Table 2-11.

Table 2-11. Authorized and Actual Electric Decoupled Revenue per Customer.

	---------- Residential ----------			---------- Non-Residential ----------		
Year	**Authorized**	**Received**	**Percent Difference**	**Authorized**	**Received**	**Percent Difference**
2020	$735	$739	0.6%	$4,380	$4,064	-7.2%
2021	$787	$811	3.1%	$4,503	$4,436	-1.5%
2022	$862	$938	8.7%	$4,795	$4,785	-0.2%

Avista received more decoupled revenue per customer from the residential group than was authorized in each of the evaluation years, 2020 through 2022. The difference was the largest in 2022. Decoupled revenue per customer for the non-residential rate group fell short of authorized levels in each evaluation year shown in Table 2-11, with the largest difference observed in 2020. Analysis of the factors behind these differences is presented in this section.

Test year and actual electric usage, customer counts and use per customer are shown for each deferral year in Table 2-12.

Table 2-12. Test Year and Actual Electric Usage, Customers, and Use per Customer.

	2020			**2021**			**2022**		
	Usage (MWh)	**Customers**	**Use per Customer (kWh)**	**Usage (MWh)**	**Customers**	**Use per Customer (kWh)**	**Usage (MWh)**	**Customers**	**Use per Customer (kWh)**
	-------------------- **Residential** --------------------								
Test Year	2,374,704	215,665	11,011	2,374,704	215,665	11,011	2,395,486	218,293	10,974
Actual (Existing)	2,429,040	217,945	11,145	2,492,451	217,802	11,444	2,592,586	219,635	11,804
Change From Test Year	54,337	2,280	134	117,747	2,137	433	197,100	1,342	830
Percent Change	2.3%	1.1%	1.2%	5.0%	1.0%	3.9%	8.2%	0.6%	7.6%
	-------------------- **Non-Residential** --------------------								
Test Year	2,131,033	36,586	58,247	2,131,033	36,586	58,247	2,131,091	37,020	57,567
Actual (Existing)	1,987,513	36,650	54,230	2,064,852	36,194	57,050	2,071,402	36,333	57,012
Change From Test Year	(143,520)	64	(4,017)	(66,181)	(392)	(1,197)	(59,689)	(687)	(555)
Percent Change	-6.7%	0.2%	-6.9%	-3.1%	-1.1%	-2.1%	-2.8%	-1.9%	-1.0%

Avista relies on volumetric charges to recover a portion of fixed costs for all decoupled rate groups and fuels. This causes use per customer to be an important factor in determining deferral balances and decoupling rates through the decoupling mechanism. More specifically, changes in use per customer from levels used in the test year to set decoupled revenue per customer will lead to positive or negative deferral balances depending on the direction of change, all other things equal. Higher use per customer will cause negative deferrals and lower use per customer will result in higher deferrals, again all other things equal.

Considering electric residential as an example, actual decoupled revenue per customer was 8.7% higher than authorized in 2022 (Table 2-11). During the same period existing customer counts were 0.6 percent higher than the test year and use per customer was 7.6% higher (Table 2-12).[85] As designed, use per customer explains nearly all of the higher than authorized revenue per customer. A comparison of the values in Table 2-11 and Table 2-12 shows that almost all of the variance in revenue per customer can be explained by differences in use per customer.

Two important factors causing use per customer to vary from test year are actual weather deviations from normal weather and acquired energy efficiency savings through Avista programs.[86] There are other factors, of course, but these two are either known in the case of energy efficiency or readily measurable in the case of weather. Changes due to weather are straightforward calculations. Avista provided the weather impacts and supporting monthly details by rate schedule showing the deviation in heating and cooling degree days from normal and the corresponding weather impacts. Energy efficiency impacts are calculated as cumulative savings from Avista programs since the applicable test year.

The results of these calculations are shown in Figure 2-5 for the electric residential rate group.

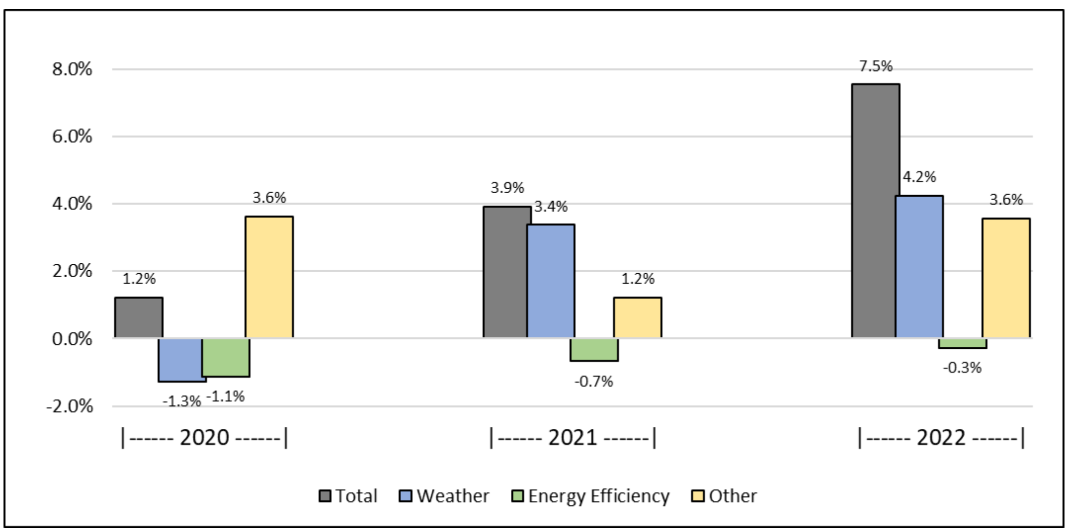

Figure 2-5: Percentage Change in Use per Customer, Electric Residential.

[85] As a result of UE-190334, effective April 1, 2020, new customers are excluded from decoupling deferrals.
[86] This analysis uses Avista's rolling thirty-year average, updated annually, for normal weather.

Considering 2021 results, use per customer was 3.9% higher than test year assumptions. Weather impacts alone are estimated to have pushed electric residential use per customer 3.4% higher. The 2021 weather impact was slightly offset by a 0.7% drop in use per customer due to Avista's energy efficiency achievements. The "Other" category is simply the difference between the total and the readily quantifiable factors of weather and energy efficiency. Other unidentified factors caused 2021 residential electric use per customer to be 1.2% higher. Weather and other factors are the primary reasons why user per customer varies from the test year.

For electric residential customers it is clear that weather impacts on use per customer can be large and work in either direction. It is also true that energy efficiency impacts always push use per customer lower and that downward influence becomes more pronounced the further in time an evaluation year is from a test year. Cumulative energy efficiency savings will reset with a new rate case and test year.

Figure 2-6 shows a plot of total and each factor's influence on the percent change in use per customer from the test year for the electric non-residential rate group.

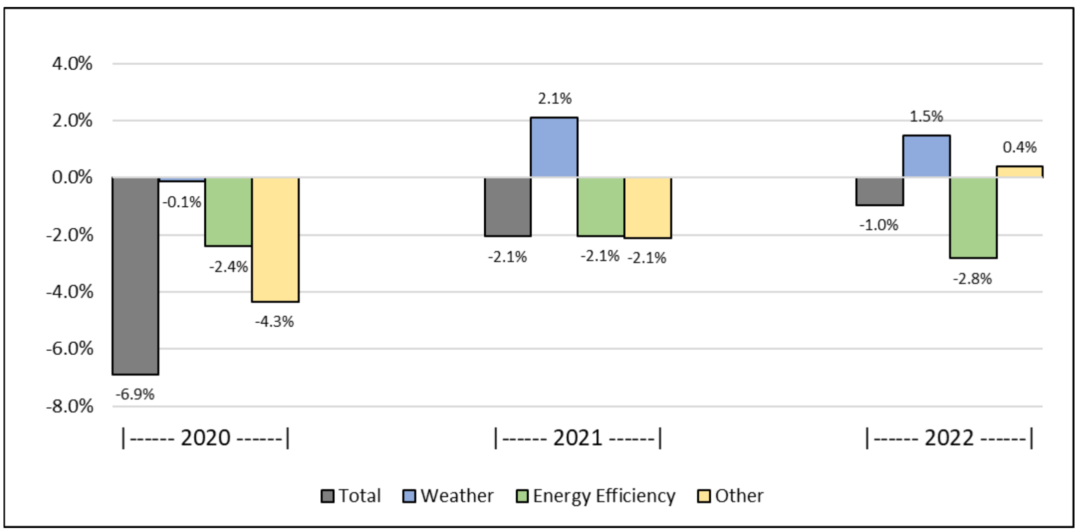

Figure 2-6: Percentage Change in Use per Customer, Electric Non-Residential.

For the non-residential electric group, weather is less a factor in use per customer variance than energy efficiency and other factors. Avista's energy efficiency achievements have been an important factor influencing changing use per customer in the electric non-residential group. Considering 2022, energy efficiency improvements were more than enough to offset greater usage due to weather and other factors, resulting in a drop of 1.0% in use per customer from test year levels. Weather appears to be far less influential in electric non-residential customer usage than it is for the electric residential group.

Actual and authorized revenue-per-customer is shown for natural gas rate groups in Table 2-13.

Table 2-13. Authorized an Actual Natural Gas Decoupled Revenue per Customer.

Year	---------- Residential ----------			---------- Non-Residential ----------		
	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6
	Authorized	Received	Percent Difference	Authorized	Received	Percent Difference
2020	$344	$337	-2.2%	$4,746	$4,597	-3.1%
2021	$388	$346	-10.7%	$5,026	$4,237	-15.7%
2022	$413	$419	1.5%	$5,184	$4,766	-8.1%

For reasons discussed above for electric, the percentage difference between authorized and actual revenue per customer shown in Table 2-13 generally follows the difference between actual and planned use per customer. However, there are notable differences, especially within the non-residential group. Actual revenue for 2021 per existing non-residential customer was much lower (15.7% lower – see Column 6) than authorized, for example. Use per customer that year was also lower (4.1% lower – see Table 2-14, Column 6, last row), a percentage far less than the 15.7% difference in revenue per customer in Table 2-13.

Test year and actual natural gas usage, customer counts and use per customer are shown for each deferral year in Table 2-14.

Table 2-14. Test Year and Actual Natural Gas Usage, Customers, and Use per Customer.

	2020			2021			2022		
	Usage (MWh)	Customers	Use per Customer (kWh)	Usage (MWh)	Customers	Use per Customer (kWh)	Usage (MWh)	Customers	Use per Customer (kWh)
	Col. 1	Col. 2	Col 3.	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9
	-------------------- Residential --------------------								
Test Year	128,985,980	161,791	797	128,985,980	161,791	797	132,095,604	165,362	799
Actual (Existing)	125,670,758	164,450	764	123,112,807	164,302	749	138,218,167	166,593	830
Change From Test Year	(3,315,222)	2,659	(33)	(5,873,173)	2,511	(48)	6,122,563	1,232	31
Percent Change	-2.6%	1.6%	-4.1%	-4.6%	1.6%	-6.0%	4.6%	0.7%	3.9%
	-------------------- Non-Residential --------------------								
Test Year	55,884,877	3,073	18,186	55,884,877	3,073	18,186	60,325,922	3,105	19,432
Actual (Existing)	55,210,492	3,119	17,699	54,798,292	3,142	17,442	62,203,363	3,274	18,998
Change From Test Year	(674,385)	46	(487)	(1,086,585)	69	(744)	1,877,441	170	(434)
Percent Change	-1.2%	1.5%	-2.7%	-1.9%	2.2%	-4.1%	3.1%	5.5%	-2.2%

For residential natural gas customers, use per customer differences from test year values followed the same pattern as revenue per customer differences from authorized. For example, in 2021 revenue per customer was 10.7 percent under the authorized level (Table 2-13, Column 3).

The drop in use per customer explains most of the shortfall between actual and authorized revenue per residential customer in 2021. This is not the case for the non-residential rate group in 2021 where the use per customer drop of 4.1 percent (Table 2-14, Column 6, Percent Change) explains less than half of the 15.7 percent shortfall in actual revenue per customer from authorized levels (Table 2-13, 2021, Column 6). A similar pattern is present in 2022 non-residential.

Two important factors causing use per customer to vary from test year are actual weather deviations from normal weather and acquired energy efficiency savings through Avista programs. There are other factors, of course, but these two are either known in the case of energy efficiency or readily measurable in the case of weather. Changes due to weather are also straightforward calculations. Avista provided the weather impacts and supporting monthly details by rate group showing the deviation in heating and cooling degree days from normal and the corresponding weather impact on usage. Energy efficiency impacts are calculated as cumulative savings from Avista programs since the applicable test year.

The results of these calculations are shown in Figure 2-7 for the natural gas residential rate group.

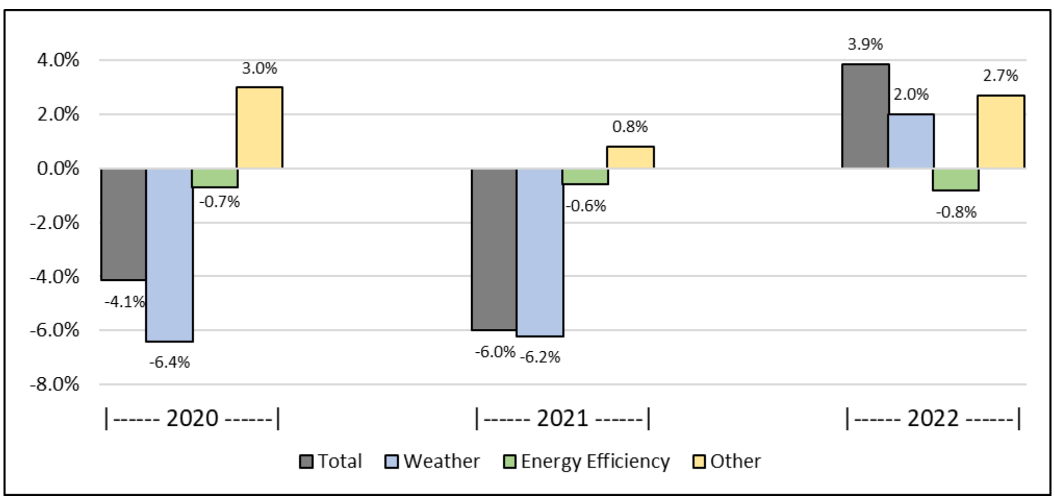

Figure 2-7: Percentage Change in Use per Customer, Natural Gas Residential.

Weather is clearly the predominant factor in understanding changes in residential therm use per customer from the test year. The total change in use per customer tracks the warmer than normal heating seasons in calendar years 2020 and 2021 and slightly colder than normal heating season in calendar year 2022. Energy efficiency impacts on use per customer usage are a small factor in understanding overall change from the test year. Other unidentified factors were largest in 2020 and 2022 but relatively small in 2021.

Figure 2-8 shows a plot of total and each factor's influence on the percent change in use per customer from test year assumptions for the natural gas non-residential rate group.

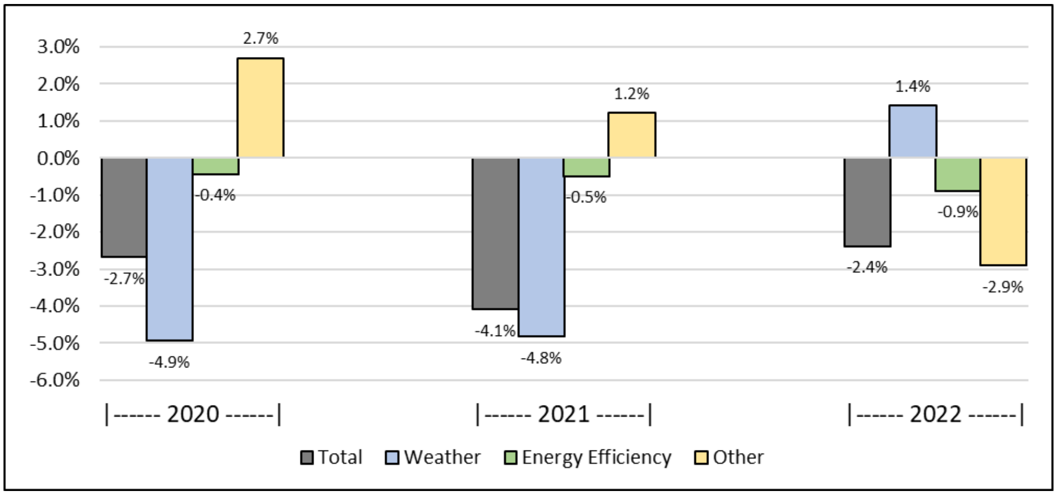

Figure 2-8: Percentage Change in Use per Customer, Natural Gas Non-Residential.

Use per customer declines in 2020 and 2021 are largely explained by warmer than normal weather. Considered independently, weather in 2022 tended to increase use per customer. However other factors and energy efficiency more than offset weather leading to a drop of 2.4 percent. Other factors are by definition unquantified but could include increased efficiency outside of Avista's energy efficiency programs, lower use of natural gas due to fuel substitution (e.g., increased use of biomass in cogeneration) and cutbacks in customer facility operations. Energy efficiency has contributed to increasingly lower use per non-residential natural gas customers.

Results of Avista's electric and natural gas energy efficiency programs are discussed in detail in Section 4 of this report.

Summary – Revenue and Billing

Avista's decoupling mechanism has had a stabilizing effect on revenue, reducing variability in half for electric and by one-fifth for natural gas of variability without decoupling. On the electric side, between 2018 and 2022 the 3% cap on annual rate increases from the decoupling rate was reached once for residential and twice for non-residential. For natural gas, the rate cap was reached once between 2018 and 2022 in each rate group, residential and non-residential.

Since 2018, the requested recovery from decoupling deferrals have worked to both increase (customer surcharge) and decrease (customer rebate) Avista’s revenues in all but the natural gas non-residential rate group. Requested recovery from deferrals in the natural gas non-residential rate group have worked to increase Avista revenues in each decoupling year between 2018 and 2022. Deferral balances are driven largely by differences in use per customer from test year assumption. Much of the difference in use per customer is due to weather, especially in electric residential, natural gas residential and natural gas non-residential. Avista’s energy efficiency programs have also worked to lower use per customer, especially for the electric non-residential group.

Section 3. Fixed Cost Recovery for Non-Decoupled Classes

Here we examine fixed costs and fixed charges for electric and natural gas customer classes.

The objective of this section, as stated in the request for proposal, is shown below:

> *"Analysis of the extent to which fixed costs are recovered in fixed charges for the customer classes, excluded from the Mechanisms."*

Relating to this objective is the following evaluation question, also taken from the RFP:

> *"How much of Avista's fixed costs recovered from non-decoupling customer classes are recovered in fixed charges?"*

The scope of this section was expanded to include decoupled electric and natural gas customer classes to facilitate comparison to customer classes excluded from the decoupling mechanisms. To address the evaluation objective, it is necessary to compare revenues from fixed charges to fixed costs for these customer classes. Fixed cost and revenue collected from fixed charges was provided by Avista in response to the data needs associated with this section. The data provided by Avista were based on their most recent cost of service completed in 2020 and approved cost of service values from rate cases in 2021 (UE-200900 for electric and UG-200901 for natural gas). Beginning with electric customer classes, we examine the recovery of fixed costs through fixed charges and the relationships presented in the data.

Electric Customers

Fixed customer charges as a percentage of fixed cost are shown in Figure 3-1 by customer classes included in Avita's cost of service study. This data shows the percentage of fixed cost recovered through fixed charges by electric customer class. The Non-Decoupled classes are Extra Large General Service and Street & Area Lighting.

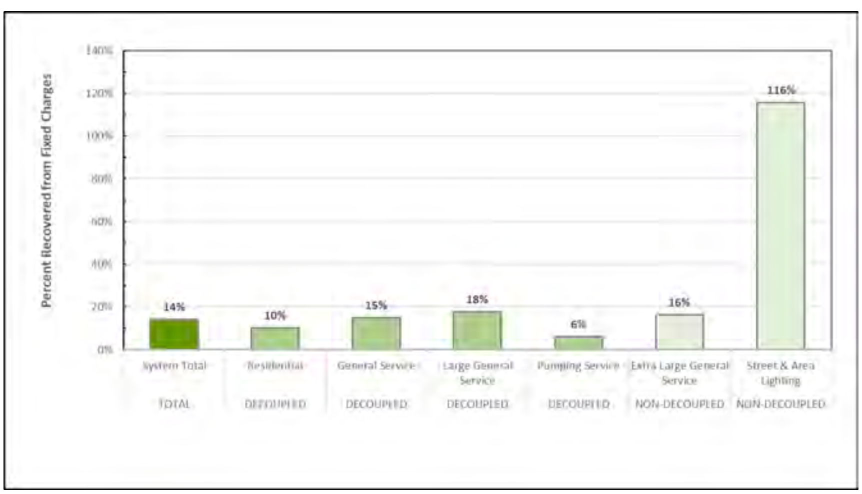

Figure 3-1. Percent Electric Fixed Cost covered by Fixed Charges.

Overall, fixed charges for total electric distribution recover about 14 percent of fixed cost. The customer class that covers the highest percentage of fixed costs through fixed charges is street and area lighting, with over 100 percent of fixed cost recovered through fixed charges. The customer class collecting the smallest percentage of fixed costs through fixed charges is pumping services. Pumping services recover 6 percent of fixed cost through fixed charges. Only about 10 percent of residential fixed costs are recovered through fixed charges compared to 15 to 18 percent for non-residential, excluding pumping services.

Natural Gas Customers

Annual revenue from fixed charges and fixed costs are shown for natural gas customer classes in Figure 3-2.[87] The Non-Decoupled classes are Interruptible Service and Transportation Service.

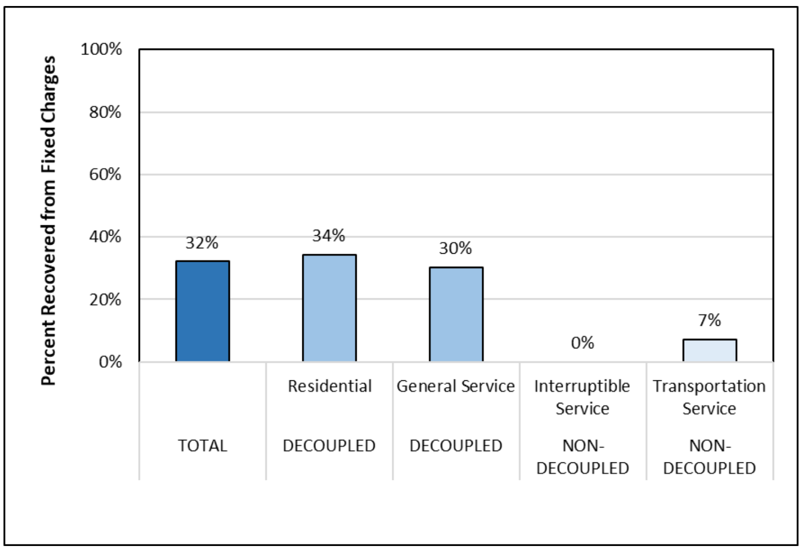

Figure 3-2. Percent Natural Gas Fixed Cost covered by Fixed Charges.

Overall, fixed charges for total natural gas recover around 32 percent of fixed cost. At 34 percent, residential customers cover the highest percentage of fixed costs through fixed charges. General services recover 30 percent of fixed costs through fixed charges. Non-

[87] Avista's natural gas cost of service studies use different customer groupings than the decoupling mechanism. The cost-of-service roll-up combines Schedules 111 (General Services) and Schedule 112 (Large General Services). Consequently, only one non-residential decoupled customer class is shown in the analysis of natural gas recovery of fixed cost through fixed charges.

decoupled customer classes recover the smallest percentage of fixed cost through fixed charges. Fixed charges revenue as a percentage of fixed cost is zero for interruptible services. Fixed costs are a very small level of the total costs for this customer class. The percentage of fixed cost recovered through fixed charges from transportation service is about 7 percent.

Summary – Recovery of Fixed Charges (Non-Decoupled Classes)

For electric non-decoupled classes, Avista recovers 16% of fixed charges for Extra Large General Service and 100% of fixed charges for Street and Area Lighting through the customer charge. For natural gas non-decoupled classes, Avista recovers no revenue for Interruptible Service and 7% of fixed charges for Transportation Service through the customer charge.

Overall (system total), Avista recovers about 14 percent of total electric fixed cost through fixed customer charges. The percentage runs lower for residential and larger for non-residential. On the natural gas side, overall fixed charges recover 32 percent of fixed costs with a slightly higher percentage of recovery in the residential customer class than non-residential customer classes.

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Section 4. Conservation Trends and Performance

This section provides an analysis of each Mechanism's impact on conservation achievement, in total and by sector (residential, low-income, non-residential), and identification of conclusive or meaningful trends in the performance of Avista's electric and natural gas conservation programs since the inception of the Mechanisms (*i.e.*, did Avista achieve a higher level of savings with the mechanisms in effect). This analysis is based on information already available as part of Avista's biennial conservation achievement evaluations filed with the Commission including changes to program delivery strategies as reported in annual evaluations, significant changes in program budgets, or reported savings levels. The specific questions addressed in this section are:

1. Were there any differences in conservation program savings, expenditures, and customers served between low-income customers and the rest of the residential class related to Decoupling?

2. Were there any trends in the performance of Avista's conservation programs since the inception of the Mechanisms, both in total and by sector (i.e., low-income, residential, and non-residential)?

3. Have the Mechanisms had an impact on natural gas conservation savings?

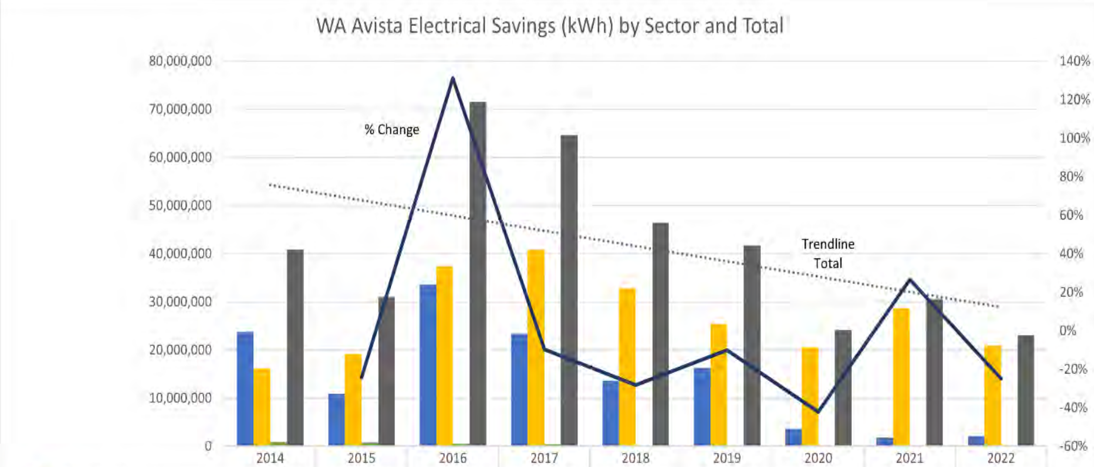
4. Have the Mechanisms had an impact on electric conservation savings (excluding the decoupling commitment to energy savings of 5%)?

Performance Trends: Total and by Sector

The analysis of performance Trends of Avista's Washington conservation programs is based on the energy savings and efficiency expenditures reported in the Washington Avista Annual Conservation Reports (2014-2022). These reports validate and summarize energy savings and expenditure data for Avista's Washington Electric and Natural Gas Conservation Programs and provide the source of annual data for trend analysis. The data was copied from the individual annual reports and compiled into spreadsheets to develop a conservation program trend analysis of performance and expenditures. The performance trend analysis provides a set of graphs and tables designed to identify conclusive and meaningful trends based on reported energy savings and expenditures data. In this section of the report, analysis identifies trends but does not attempt to attribute causality to the trends, except for noting negative performance effects attributable to the Covid pandemic in the 2021 Avista Conservation Report. For this analysis 'Total Residential' includes information for both 'Residential' and 'Low-Income Residential.'

Electrical Energy Savings

Total Annual Electrical Conservation program savings (Figure 4-1) increased 131% in 2016, the year following the implementation of the Mechanism in 2015. However, since 2016, the Total Savings line has trended downward, with one annual increase in 2021, in the non-residential sector. Overall, the negative electrical savings trend is driven by declines in the residential sector's annual savings rate. The residential downward trend accelerates in 2020 with a 42% decline from the savings achieved in 2019, which can be reasonably attributed to the impact of the Covid-19 Pandemic. The residential sector savings rate continues to remain substantially below pre-pandemic levels through 2022.



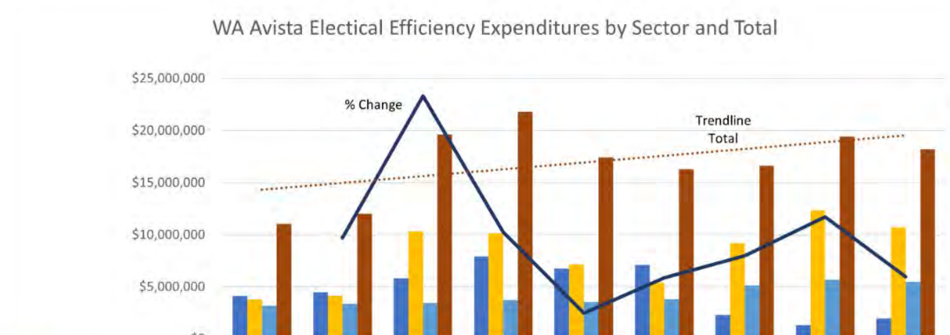
	2014	2015	2016	2017	2018	2019	2020	2021	2022
Total Residential	23,784,974	10,926,176	33,589,134	23,330,658	13,607,612	16,307,468	3,601,842	1,874,877	2,119,973
Non-residential	16,226,327	19,167,758	37,420,578	40,859,838	32,834,855	25,433,281	20,584,356	28,743,276	20,900,684
Generation and Distribution	885,000	877,000	561,990	476,000	0	0	0	0	0
Total Savings	40,896,301	30,970,934	71,571,702	64,666,496	46,442,467	41,740,749	24,186,198	30,618,153	23,020,657
% Change Total Savings		-24%	131%	-10%	-28%	-10%	-42%	27%	-25%

Figure 4-1: Electrical Energy Savings (kWh by Sector and Total).

Electrical Expenditures

The total annual electrical efficiency program expenditure data (Figure 4-2) indicates a general upward trend in spending over the 2014-2022 period, with leveling and a slight decline since 2017. Annual kWh savings high reached in 2017 ($21,787,386) has not been matched as of 2022 reported data. There is a clear downward trend in residential electrical efficiency expenditures since 2017, with a precipitous decrease in 2020 which can be reasonably attributed to the Covid-19 pandemic. This decrease in residential expenditure mirrors the Covid impact of residential kwh annual savings rates.

Counter to the residential decline, Non-Residential (Commercial and Industrial) spending began a strong upward trend just as residential expenditures were declining.

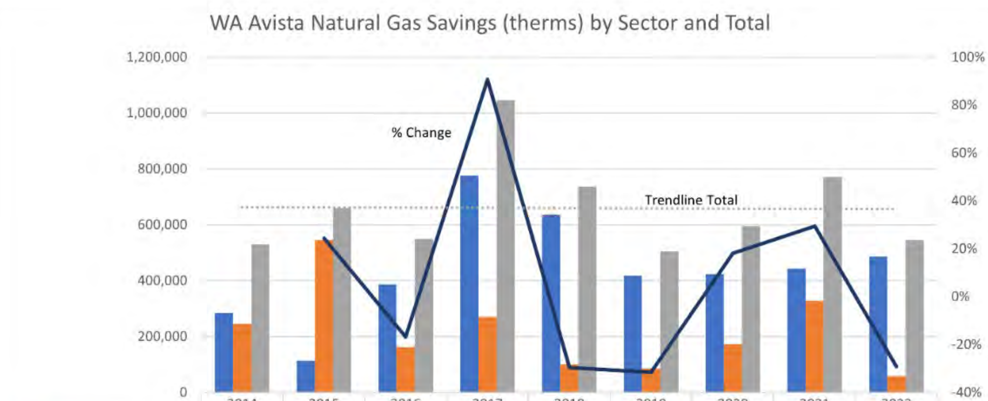


	2014	2015	2016	2017	2018	2019	2020	2021	2022
Total Residential	$4,115,619	$4,468,709	$5,828,459	$7,904,390	$6,724,100	$7,096,768	$2,298,239	$1,322,625	$1,978,613
Nonresidential	$3,781,678	$4,162,940	$10,339,410	$10,147,062	$7,148,781	$5,392,870	$9,181,515	$12,369,954	$10,722,483
Regional & General	$3,157,730	$3,389,514	$3,458,742	$3,745,934	$3,546,495	$3,799,768	$5,131,183	$5,712,259	$5,500,711
Total Efficiency Expenditures	$11,055,027	$12,021,163	$19,636,611	$21,797,386	$17,419,376	$16,289,406	$16,610,937	$19,404,838	$18,201,807
% Change Total Expenditures		9%	63%	11%	-20%	-6%	2%	17%	-6%

Figure 4-2: Electrical Efficiency Expenditures ($) by Sector and Total.

Natural Gas Energy Savings

The total Natural Gas Savings trend line is level with some cyclicality (Figure 4-3 The natural gas savings rate for the residential sector generally exceeds that in the nonresidential sector. Nonresidential savings showed strong increases in 2020 and 2021 and then declined in 2022.



	2014	2015	2016	2017	2018	2019	2020	2021	2022
Total Residential	284,732	114,150	386,381	776,064	636,781	418,545	422,975	442,852	486,950
Nonresidential	245,031	544,883	162,375	270,293	100,205	85,567	172,357	327,595	58,819
Total Savings	529,763	659,033	548,756	1,046,357	736,986	504,112	595,332	770,447	545,769
% Change Total Savings		24%	-17%	91%	-30%	-32%	18%	29%	-29%

Figure 4-3: Natural Gas Energy Savings (Therms) by Sector and Total.

Natural Gas Expenditures

Total Annual Natural Gas Efficiency Program Expenditures trended level over the 2014-2022 period with inflection to higher rates of increase in 2019 (Figure 4-4, green dotted line). Total Residential Natural Gas expenditures show a steady but modest increase over 2014-2022 period and there was a strong (55%) year-to-year nonresidential spending increase in 2020. The 2018 to 2022 period also shows a positive trend in Regional and General efficiency expenditures.

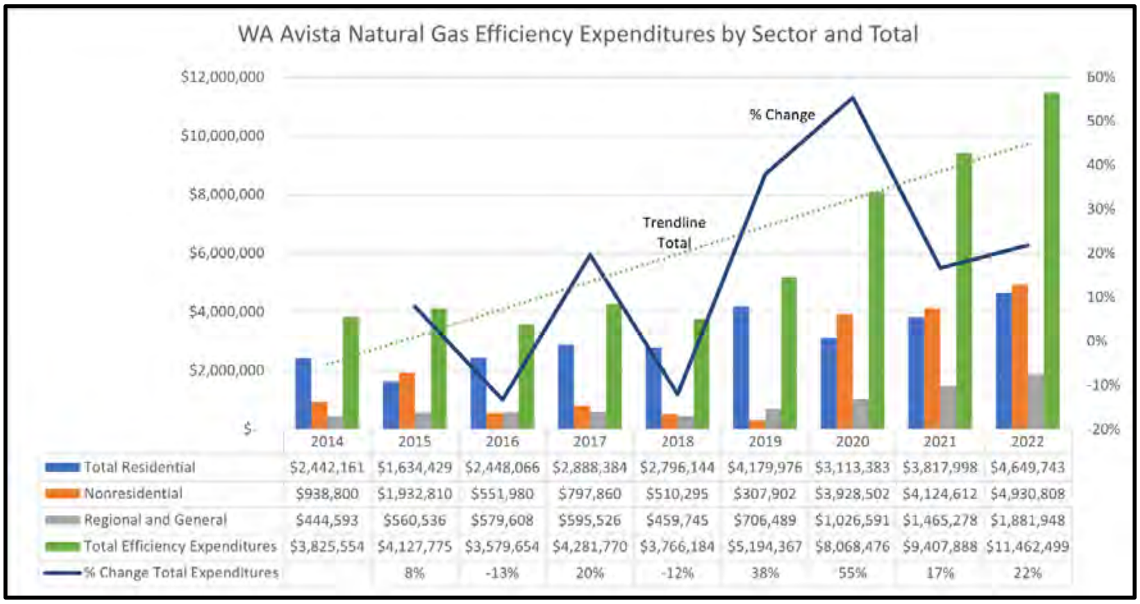


Figure 4-4: Gas Efficiency Expenditures by Sector and Total.

Residential and Low-Income Program Performance

Total Residential Electrical Savings Trend

As shown in Figure 4-5, overall, the trend line for Total Annual Residential Electrical decreases (green dotted line, sloping downward) over the 2014-2022 period. After increasing in 2015 by 24%, the savings rate increases in 2016 by 131%. In 2017, annual residential savings began a declining trend through 2022. This decline began in 2018, three years before the Covid-19 pandemic.

Savings rates were then significantly impacted by Covid-19 with a 42% drop in 2020. Recovery to pre-Covid level has not been attained.

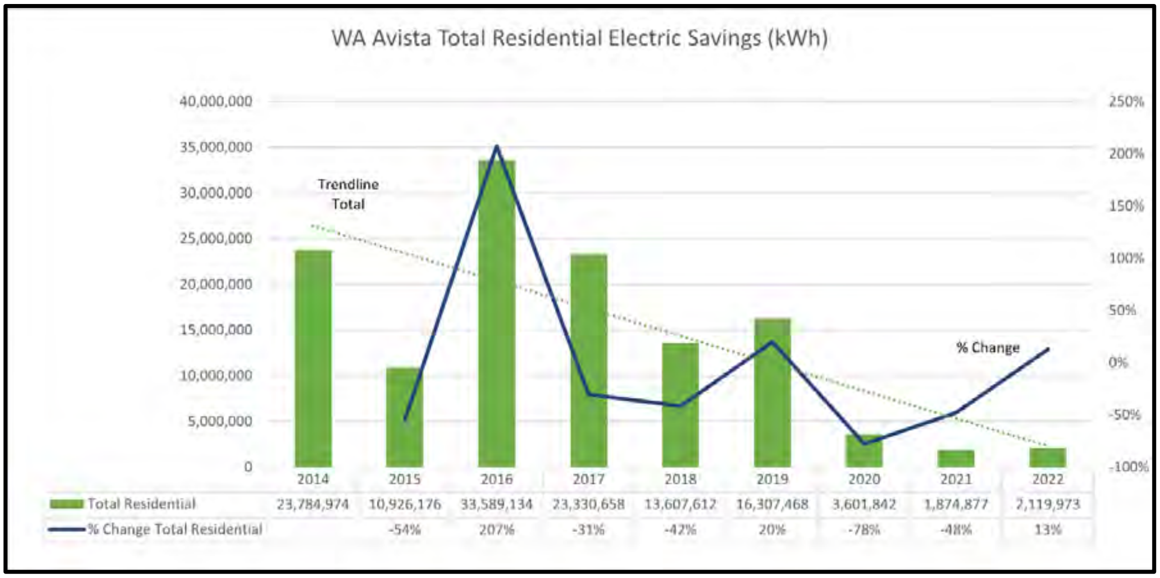


Figure 4-5: Total Residential Electrical Savings (kWh).

Low-Income Electric Savings Trends

In contrast to Total Residential (Figure 4-5), the Low-income Savings (kwh) trend line increased from 2014 to 2022 (Figure 4-6, blue dotted line, upward sloping). Low-income savings as a percentage of Total residential savings was fairly level from 2014 through 2019 (Figure 4-7). In 2020, there was a strong increase of 55% over 2019 as Covid shut down much regular residential work. There was a further increase of 17% from 2020 to 2021, and an increase of 22% from 2021 to 2022.

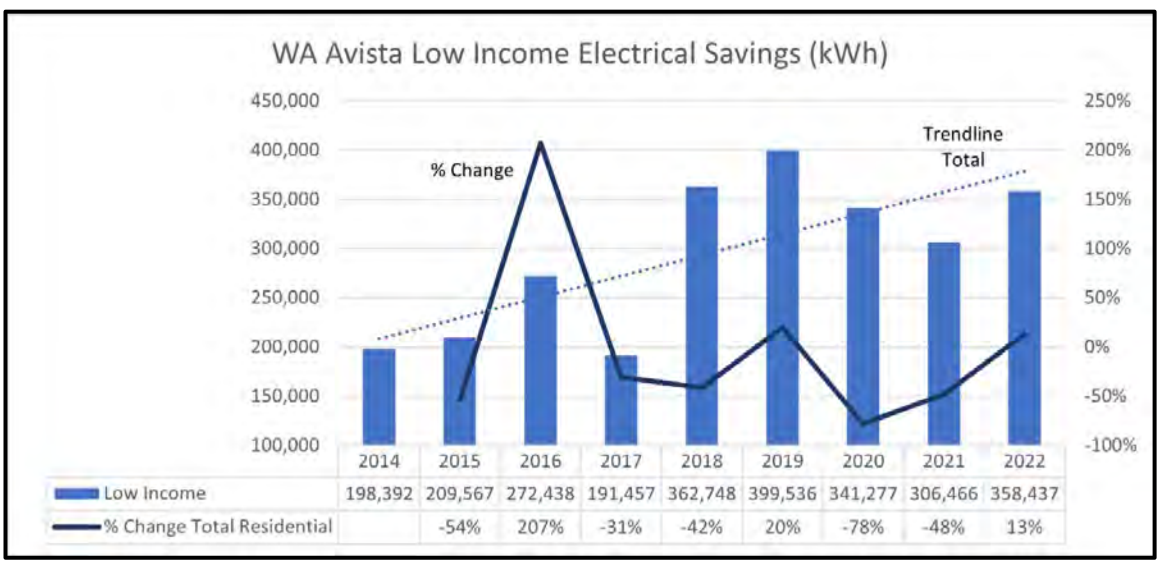
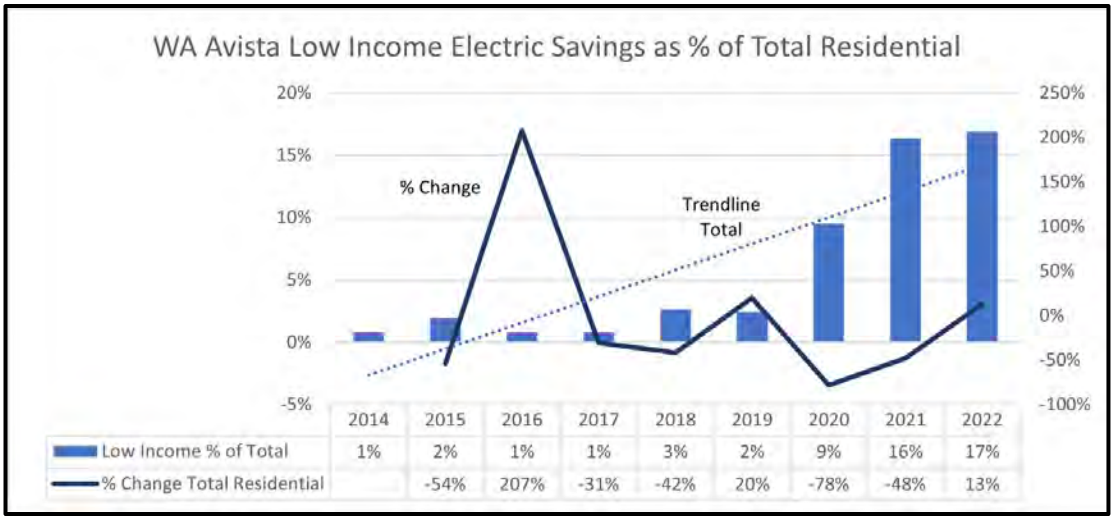


Figure 4-6: Low-Income Electrical Savings (kWh).

The Low-Income percentage of Total Residential savings also increased (Figure 1-7).

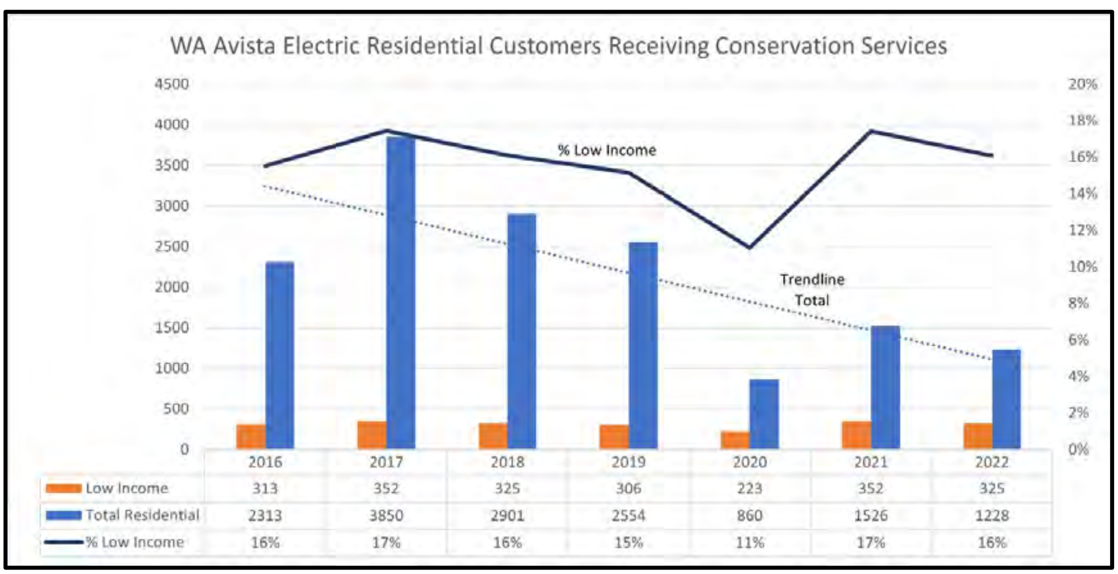


	2014	2015	2016	2017	2018	2019	2020	2021	2022
Low Income % of Total	1%	2%	1%	1%	3%	2%	9%	16%	17%
% Change Total Residential		-54%	207%	-31%	-42%	20%	-78%	-48%	13%

Figure 4-7: Ratio of Low-Income to Total Residential Electrical Savings (%).

Number of Electrical Residential and Low-Income Receiving Conservation Services

The 2016-2022 trend line in the number of WA Avista electrical residential customers (Figure 4-8) served with conservation services was negative. The percentage of Low-Income customers served remained stable, averaging 16% over the period.



	2016	2017	2018	2019	2020	2021	2022
Low Income	313	352	325	306	223	352	325
Total Residential	2313	3850	2901	2554	860	1526	1228
% Low Income	16%	17%	16%	15%	11%	17%	16%

Figure 4-8: Number of Residential Electrical Customers Receiving Conservation Services.

Electric Residential Expenditures

The Total Residential Electrical Efficiency Expenditures trend line (orange dotted line in Figure 4-9) shows the general downward trend in expenditures during the entire 2014-2022 period. Within this trend, however, expenditures increased 30% in 2016 and 36% 2017 and stabilized through 2018 and 2019. In 2020 residential electric efficiency expenditures declined by 68%, reasonably attributed to the Covid-19 pandemic. Total Residential efficiency expenditure decreased again in 2021 by 42%, again reasonably attributed to the pandemic. In 2022 expenditures increased by 50% over the 2021 low point.

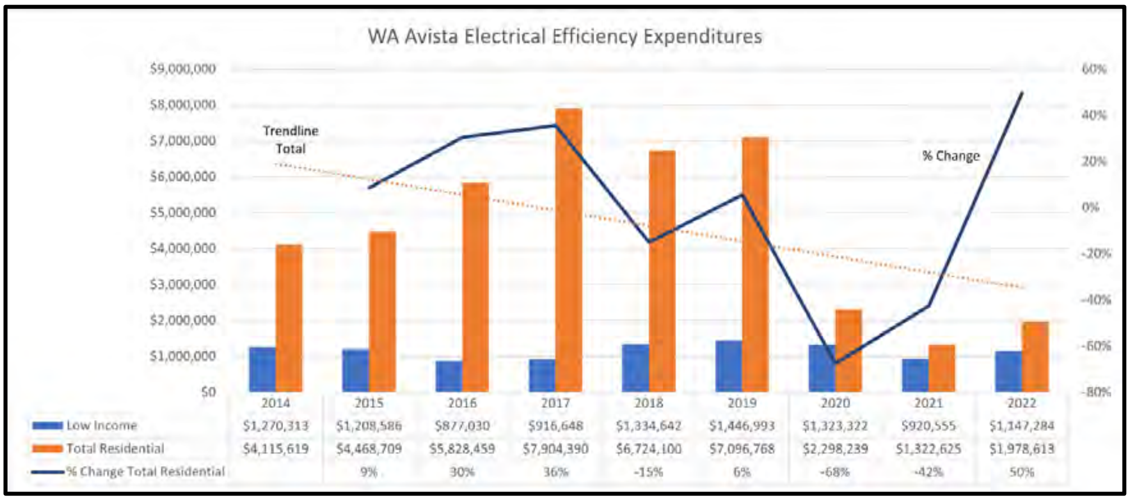


Figure 4-9: Residential Electrical Expenditures ($).

As shown in Figure 4-10, the Low-Income electrical efficiency expenditures trend line (dotted blue horizontal line) is level with variations from year to year.

Figure 4-11 shows the increase in low-income spending for electrical efficiency (upward sloping, dotted brown line) from year to year. Within this overall trend, the proportion of low-income spending decreased from 2014 through 2017, then showed strong year-over-year increases from 2018 through 2021 with a decrease from 2021 to 2022.

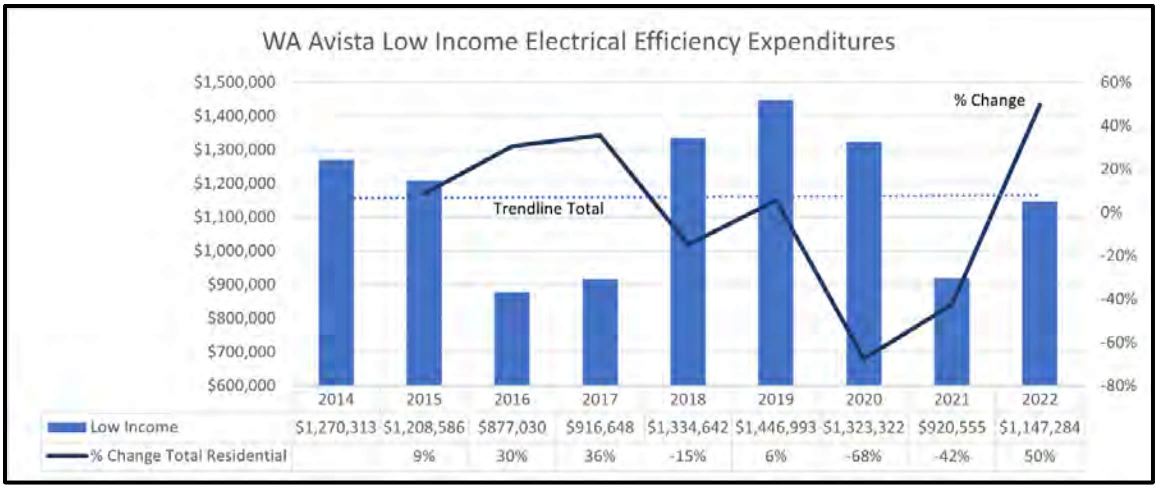


Figure 4-10: Electrical Low-Income Spending ($).

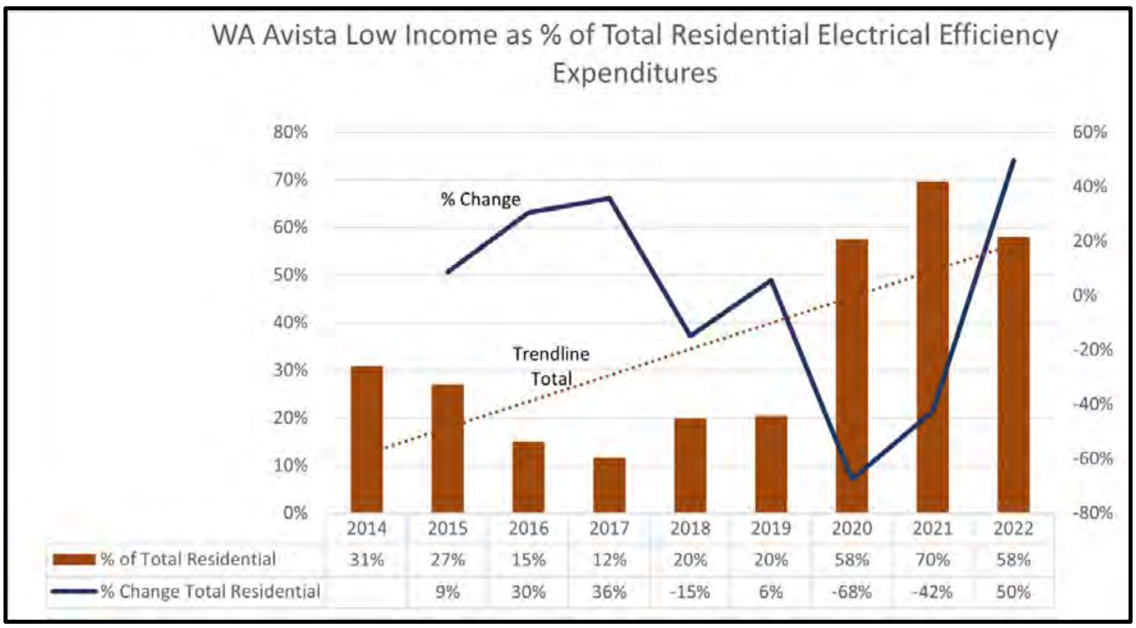


Figure 4-11: Ratio of Low-Income to Total Residential Electrical Spending (%).

On average, per customer, electrical conservation expenditures reflected a relatively stable slightly increasing trend (Figure 4-12) from 2017 to 2020. Average expenditures dropped in 2021 with a slight recovery in 2022. Average electric conservation expenditures for low-income customers are slightly higher than for non-low-income residential customers.

Figure 4-12: Average Residential Electric Customer Conservation Expenditures ($).

Total Residential Natural Gas Savings Trend

The trend in Residential Natural Gas Savings (therms) has been positive with some variability from year to year in the annual rate (Figure 4-13), upward sloping brown dotted line). Within this trend, there was a decrease of 60% from 2014 to 2015, an increase of 238% from 2015 to 2016, an increase of 101% from 2016 to 2017, and then a decrease of 18% from 2017 to 2018 and a further decrease of 34% from 2018 to 2019. From 2019 through 2022, there has been a slow increase in residential natural gas savings.

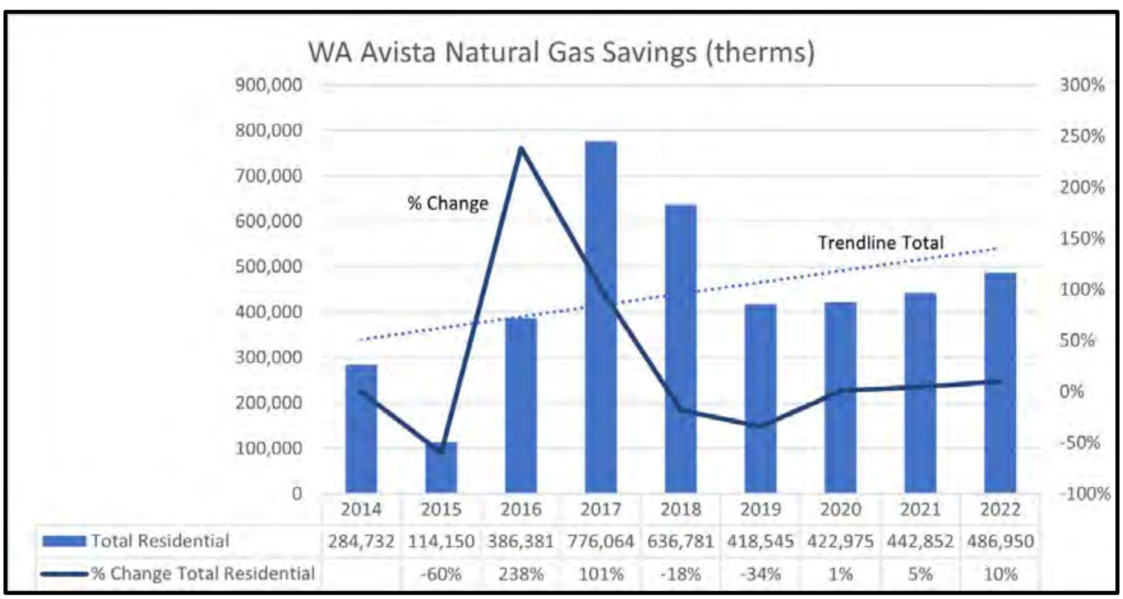


Figure 4-13: Total Residential Natural Gas Savings (Therms).

Low-Income Natural Gas Savings Trends

The overall Low Income Natural Gas Savings trend reflects a modest annual increase in savings with variability from year to year (Figure 4-14)

Low Income savings as a percent of Total Residential Natural Gas Energy Savings was relatively consistant from 2014 to 2022, ranging from under one-percent to about 6%. The slope of the curve is slightly downwards (dotted blue line in Figure 4-15).

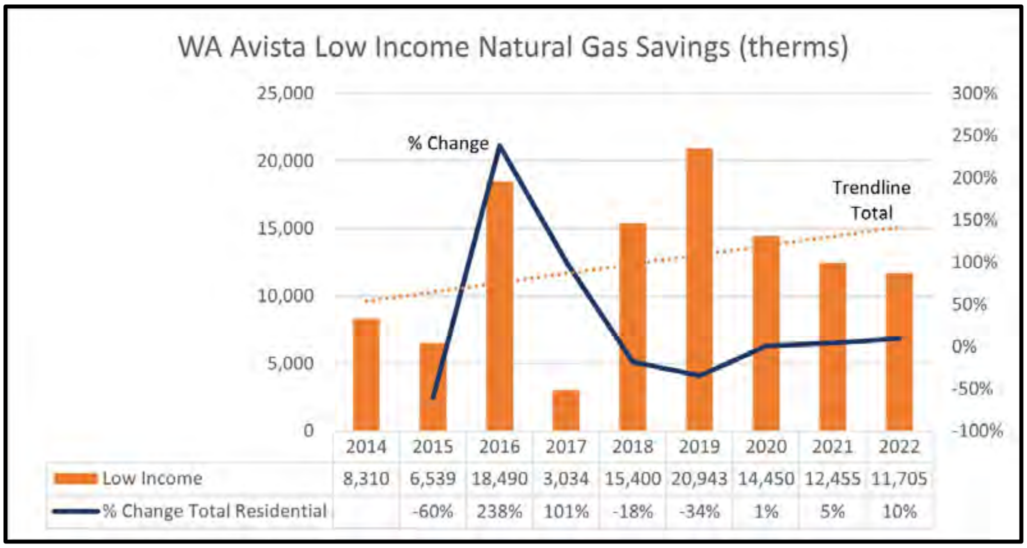


Figure 4-14: Residential Low-Income Natural Gas Savings (Therms).

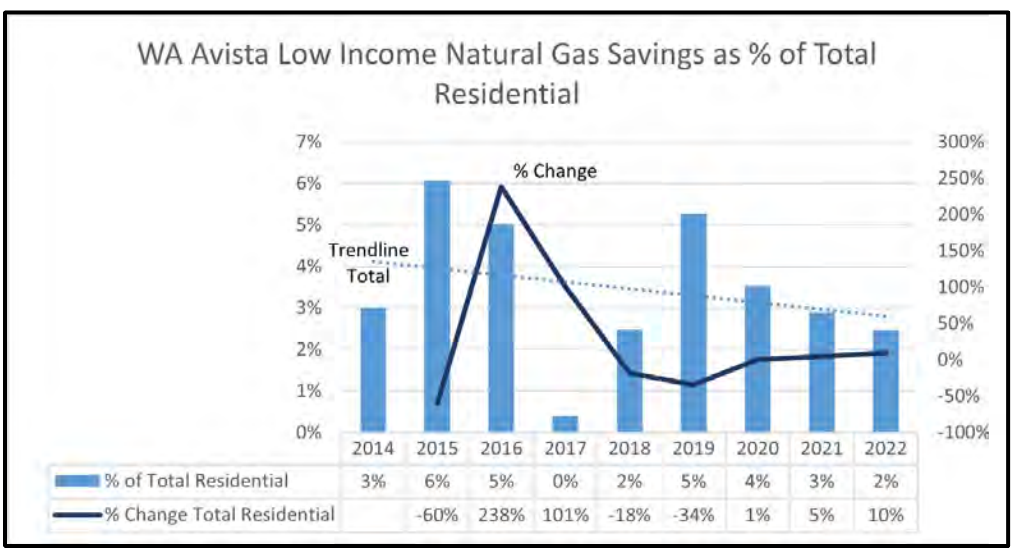
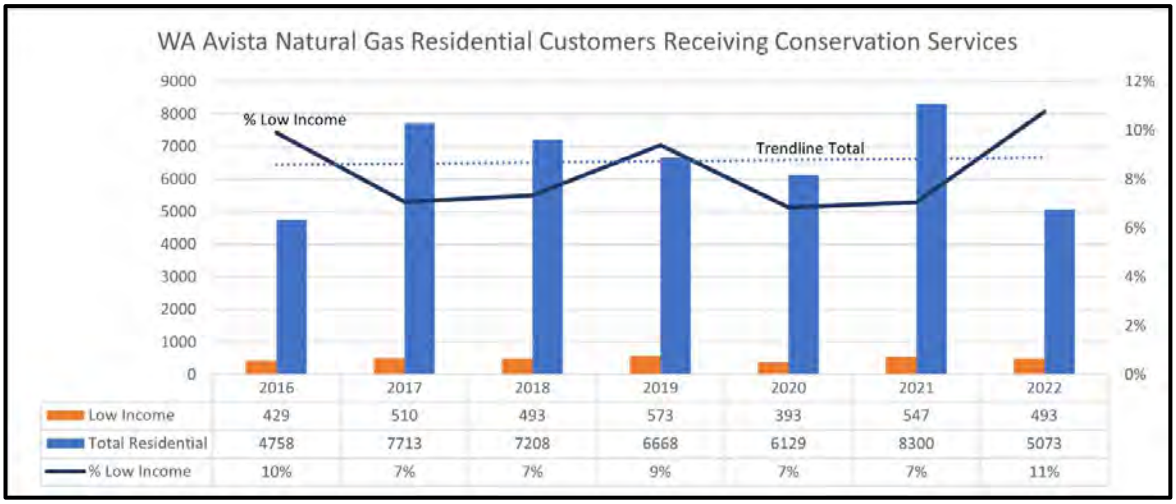


Figure 4-15: Ratio of Low-Income to Residential Natural Gas Savings (%).

Number of Natural Gas Residential and Low-Income Receiving Conservation Services

The 2016-2022 trend line (Figure 4-16) was level for the number of natural gas conservation customers. The percentage low-income remained relatively stable, averaging 8% over the period.

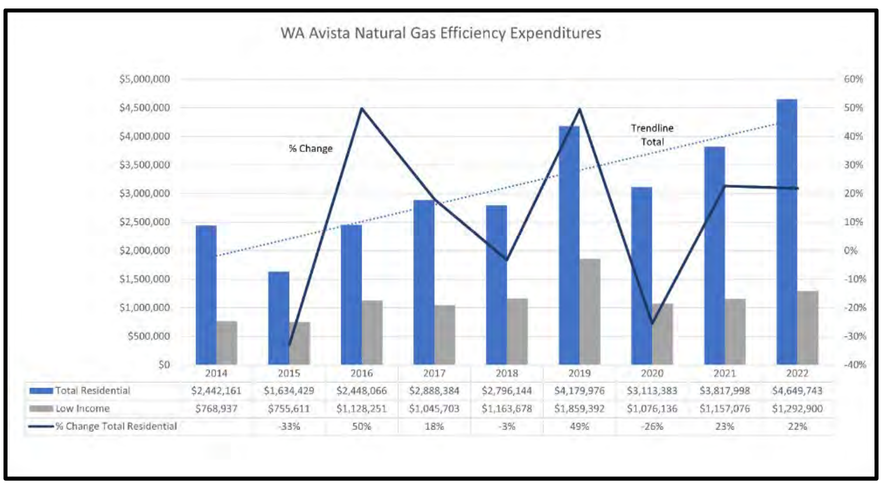


	2016	2017	2018	2019	2020	2021	2022
Low Income	429	510	493	573	393	547	493
Total Residential	4758	7713	7208	6668	6129	8300	5073
% Low Income	10%	7%	7%	9%	7%	7%	11%

Figure 4-16: Number of Gas Residential Customers Receiving Conservation Services.

Natural Gas Residential Expenditures

The Natural Gas Total Residential Efficiency Expenditure trend line has been upward during the whole 2014 to 2022 period (blue, upward sloping dotted line in Figure 4-17).



	2014	2015	2016	2017	2018	2019	2020	2021	2022
Total Residential	$2,442,161	$1,634,429	$2,448,066	$2,888,384	$2,796,144	$4,179,976	$3,113,383	$3,817,998	$4,649,743
Low Income	$768,937	$755,611	$1,128,251	$1,045,703	$1,163,678	$1,859,392	$1,076,136	$1,157,076	$1,292,900
% Change Total Residential		-33%	50%	18%	-3%	49%	-26%	23%	22%

Figure 4-17: Natural Gas Total Residential Efficiency Expenditures ($).

The overall trend for Low-Income program expenditures is an increase (Figure 4-18, upward sloping dotted blue line). Within this overall trend, spending increased from 2014 to 2019. This upward pattern was broken by a severe drop from 2019 to 2020, reasonably attributable to the Covid pandemic.

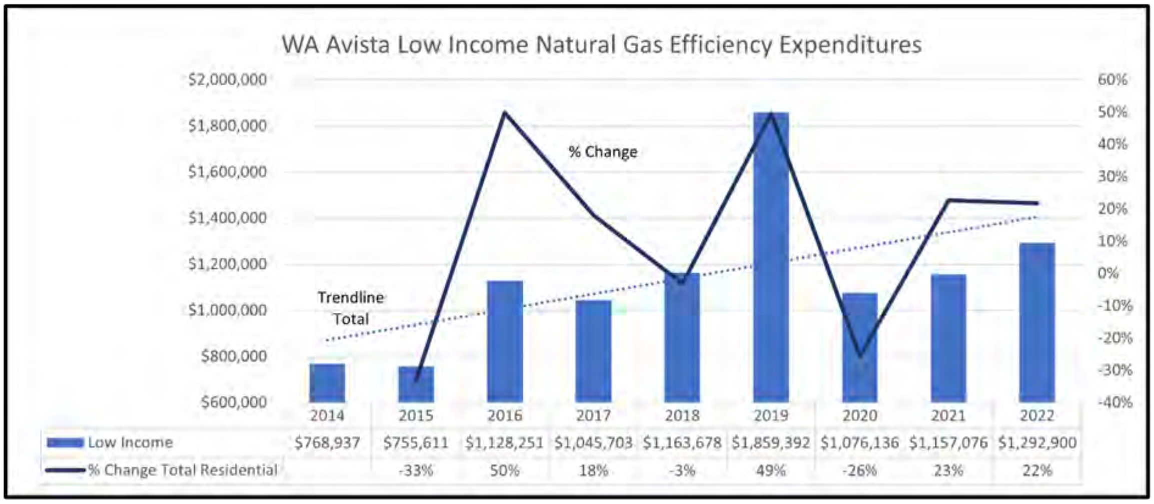


Figure 4-18: Natural Gas Low-Income Efficiency Expenditures ($).

The rate of increase, shown by the slope of the overall trend line is similar but higher for Total Residential expenditures, than for Low-Income Natural Gas Efficiency Expenditures. This falling relative share is shown in Figure 4-19 by the downward sloping dotted blue trend line.

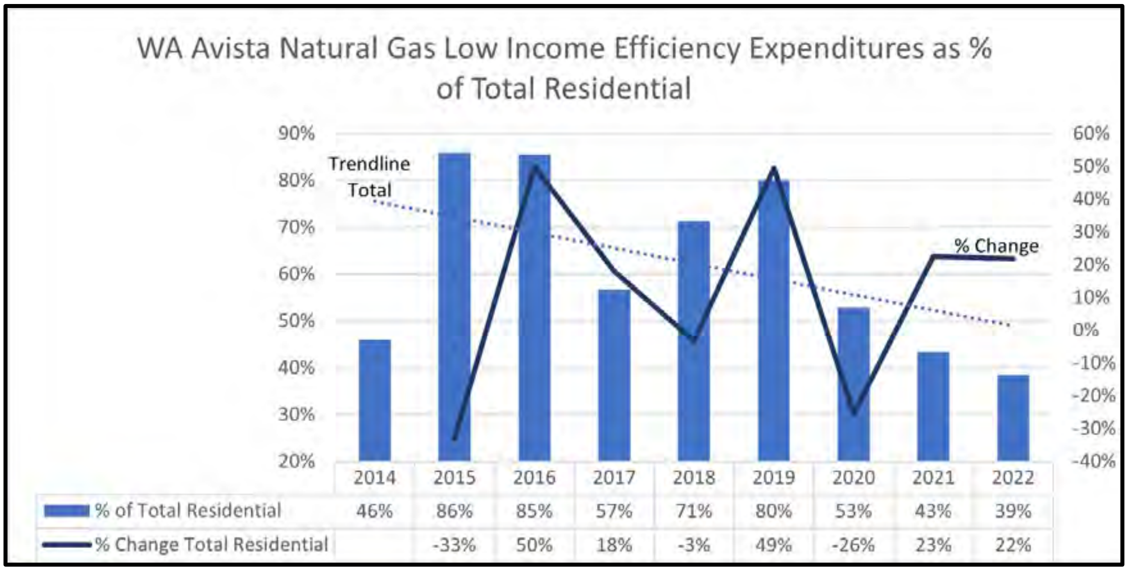


Figure 4-19: Ratio of Low-Income to Total Natural Gas Residential Spending (%).

On average, per customer, natural gas conservation expenditures reflected stable and level trend from 2017 to 2022, with a slight rise (Figure 4-20). Average natural gas conservation expenditures for low-income customers are considerable higher than for non-low-income residential customers, and, overall, are level.

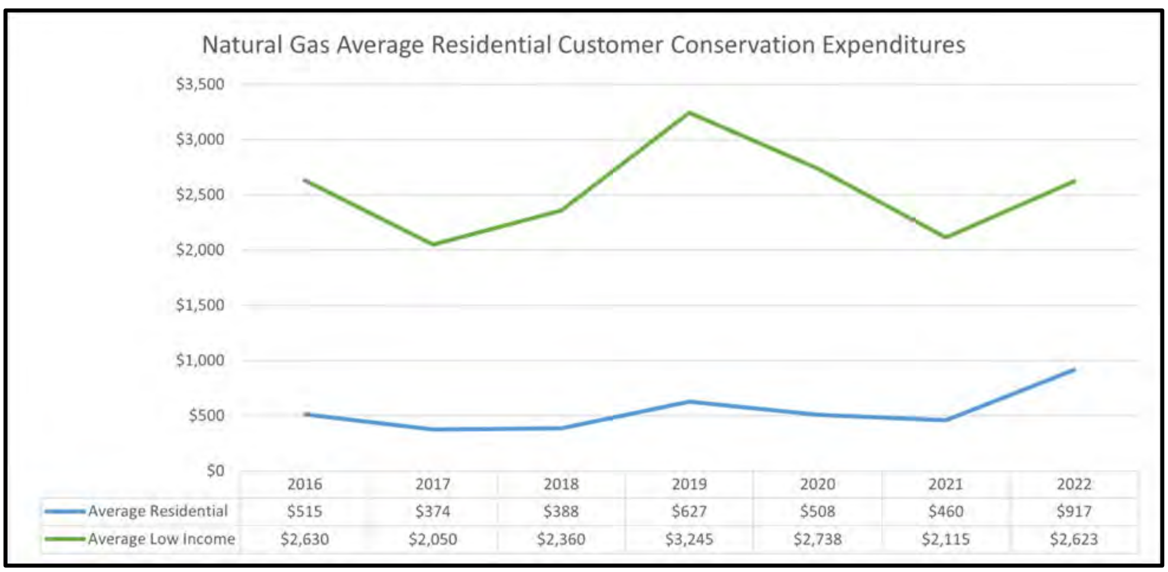


Figure 4-20: Natural Gas Average Residential Customer Conservation Expenditures ($).

Summary – Conservation

The specific questions in this section of the study, along with short answers, are as follows:

1. ***Were there any differences in conservation program savings, expenditures, and customers served between low-income customers and the rest of the residential class related to Decoupling?***

    - We find no reason to suggest a relationship between decoupling and conservation results for program savings, expenditures, and customers served. In other words, the relationships shown in the data in this section of the study are as likely to have occurred in the absence of decoupling as they actually occurred with decoupling.

    - We also find no relationship to be evident between low-income customers and the rest of the residential class related to decoupling. There are changes, but we find no reason to suggest these changes have a relationship to decoupling. The changes are likely driven by other factors.

2. ***Were there any trends in the performance of Avista's conservation programs since the inception of the Mechanisms, both in total and by sector (i.e., low-income, residential, and non-residential)?***

    - For electricity, the overall energy savings trend is *down*, (Figure 4-1) dominated by the downward trend for Total Residential (Figure 4-5). The trend line for Total Residential Electric Savings shows an overall decline from 2014 to 2022 (negative slope indicated by the green dotted line in Figure 4-5). Spending is also *down* for Total Residential (Figure 4-9). Total Residential Electric Savings have *declined* substantially over the years examined.

Table 4-1: Trends (Electricity).

Trends (Electricity)					
Energy Savings			**Efficiency Spend**		
Sector	**Slope**	**Graph**	**Sector**	**Slope**	**Graph**
Overall Electrical (kWh)	Down	Figure 1-1	Overall Electrical ($)	Up	Figure 1-2
Non-Residential (kWh)	Slight Up	Figure 1-1	Non-Residential ($)	Up	Figure 1-2
Total Residential (kWh)	Down	Figure 1-5	Total Residential ($)	Down	Figure 1-9
Residential Low-Income (kWh)	Up	Figure 1-6	Residential Low-Income ($)	Level	Figure 1-10
Ratio of Low-Income to Total Residential Savings (%)	Up	Figure 1-7	Ratio of Low-Income to Total Residential Savings (%)	Up	Figure 1-11
Number of Residential Electric Conservation Customers	Slight Down	Figure 1-8	Average Electric Conservation Spending	Level	Figure 1-12
Number of Low-Income Conservation Customers	Level	Figure 1-8	Average Electric Low-Income Conservation Spending	Slight Up	Figure 1-12

- In contrast, Low-Income Residential Electric Savings have *increased* both absolutely (Figure 4-6) and as a percentage of Total Residential Electric Savings (Figure 4-7). For Low-Income Electric Savings (kWh) the trend line slopes upward over the same range of years examined (blue dotted line in Figure 4-6). Also, the Low-Income Electric Savings as a percentage of Total Residential Electric Savings *increased* from one percent (1%) to seventeen percent (17%) from 2014 to 2022 (Figure 4-7).

- For natural gas, Residential energy savings trends for both Total Residential and Low Income are sloping *slightly upward* (Figure 4-13 and Figure 4-14), the Ratio of Low-Income to Total Residential Savings (%) slopes *slightly downward* (Figure 4-15).

Table 4-2: Trends (Natural Gas).

Trends (Natural Gas)					
Energy Savings			**Efficiency Spend**		
Sector	**Slope**	**Graph**	**Sector**	**Slope**	**Graph**
Overall Natural Gas (Therms)	Level	Figure 1-3	Overall ($)	Up	Figure 1-4
Non-Residential (Therms)	Slight Down	Figure 1-3	Non-Residential (Therms)	Up	Figure 1-4
Total Residential (Therms)	Up	Figure 1-13	Total Residential ($)	Up	Figure 1-17
Residential Low-Income (Therms)	Up	Figure 1-14	Residential Low-Income ($)	Up	Figure 1-18
Ratio of Low-Income to Total Residential Savings (%)	Sight Down	Figure 1-15	Ratio of Low-Income to Total Residential Savings (%)	Down	Figure 1-19
Number of Residential Gas Conservation Customers	Level	Figure 1-16	Average Natural Gas Conservation Spending	Level	Figure 1-20
Number of Low-Income Gas Conservation Customers	Level	Figure 1-16	Average Gas Low-Income Conservation Spending	Level	Figure 1-20

3. **Have the Mechanisms had an impact on natural gas conservation savings?**

   - Based on the reports reviewed for this analysis, it is not evident that the mechanisms have had a positive or negative impact on natural gas conservation savings. Generally, it is likely that exogenous factors have provided substantial impact on natural gas conservation savings. However, since the slopes for both Total Residential and Residential Low-Income Natural Gas savings are positive, these results are consistent with the mechanisms having a positive effect on natural gas conservations savings. While the slope of the trend line for Non-Residential savings for natural gas is downwards, it is only slightly downwards.

4. **Have the Mechanisms had an impact on electric conservation savings (excluding the decoupling commitment to energy savings of 5%)?**

   - Based on the reports reviewed for this analysis, it is not evident that the mechanisms have had a positive or negative impact on electric conservation savings. Total Electrical savings are down, dominated by Total Residential. Non-Residential savings are up, but only slightly. While Total Residential is down, Residential Low-Income is up.

- The Annual Conservation Reports do not break down savings to exclude the 5% decoupling commitment.[88] The additional 5% decoupling savings data is addressed in setting targets in the Annual Conservation Plan but is not reported in the Annual Conservation Reports which provide the source data for the analysis here. Since the results of the 5% decoupling commitment are not specifically broken out in the Annual Conservation Reports, the Annual Conservation Plan, or the Biennial Program Evaluations, the 5% results cannot be addressed here.

In the big picture, overall electrical savings are trending downwards (Figure 4-1) while costs are trending upwards (Figure 4-2). Overall natural gas savings are trending level (Figure 4-3) while cost is trending upwards. For residential electric low-income households, savings are trending up while cost is trending level (Table 4-1). For residential natural gas households, savings are trending up, while cost is trending up (Table 4-2). Other results are summarized in Table 4-1, Trends (Electricity) and in Table 4-2 (Trends, Natural Gas).

With regard to decoupling, there is no evident impact of decoupling on energy conservation savings. This result is neither unusual nor unexpected. Decoupling is generally not considered to be a driver of energy conservation. Rather, decoupling removes a potential barrier to energy conservation, which is different than driving a direct savings effect.

[88] In the General Rate Case Settlement Agreement (Docket Nos UE-140188 and UG-140189), the Company agreed, in consideration for receiving a full electric decoupling mechanism, to increase its electric energy conservation achievement by 5% over the conservation target approved by the Commission.

Section 5. New Customer Analysis

Avista's decoupling mechanism currently applies only to customers on the system during the test year[89] used to establish allowed decoupled revenue per customer.[90] Such customers are referred to "existing" or "test-year" customers and customers added to the system after the test year are referred to as "new" customers. It is important to understand that in this context "existing" and "new" refer to premises on the system, rather than people or households.[91]

The purpose of this section is to assess the impact of new customers if they had been included in the decoupling mechanism. Avista has provided data that breaks out new customers from all customers in each decoupled rate class to determine decoupled revenue from existing customers. The same breakout allows us to also compare new customers to existing customers.

A summary of this analysis for the electric system is shown in Table 5-1. Table 5-1 shows the number of customers, use per customer, actual decoupled revenue per customer (RPC), allowed RPC, the difference between actual and allowed RPC, and the deferred revenue before interest or revenue related expenses for each year in the analysis. This information is shown for existing customers, new customers, and all customers (existing and new combined) for each customer class. What stands out from the data in Table 5-1 is that new customers are meaningfully different from existing customers in both use per customer and decoupled (distribution) revenue generated per customer.

Consider the non-residential customer class in 2022. Although the number of new customers is small relative to the number of existing customers, when calculated on a per customer basis, the generated decoupled revenue per customer is significantly smaller and substantially under the allowed revenue per customer for non-residential customers in 2022. Had new customers been included in the decoupling mechanism in 2022, deferred revenue in the non-residential customer class would have totaled $3.6 million

[89] The "test year" refers to the twelve-month period used in a utility ratemaking proceeding to establish number of customers and "typical" customer usage. A table of rate cases and associated test years is in the appendix.

[90] In Docket UE-190334 the Commission approved the Company's proposal to continue the Decoupling Mechanism for an additional five years, beginning April 1, 2020. A modification of the program specified by the Commission is that customers connected to Avista's system after the ratemaking test year will be excluded from the decoupled deferred revenue calculations. Furthermore, the Company will include a status update in its yearly decoupling report identifying the number of new customers excluded from the mechanism and associated costs and revenues.

[91] A premise on the system during the test year that subsequently experiences a change in occupancy is not considered a new customer. A premise added to the system that was not served on the system during the test year is considered a new customer. Examples of new customers in this context include new natural gas service to properties not previously served by natural gas and electric and natural gas service added to newly constructed homes and commercial structures. Although excluded from the decoupling mechanism in effect at the time the new service is established, these new customers would become existing customers in the next rate case.

instead of the $0.4 million actually reported based only on existing customers. In other words, including new customers would have resulted in an additional $3.2 million in deferred revenue that, along with additional interest revenue expenses, would be charged to customers through the decoupling tariff (RS 75).

Table 5-1. Impact of New Customers on Decoupled Deferred Revenue – Electric.

	Residential			Non-Residential		
	Existing	**New**	**All**	**Existing**	**New**	**All**
	-- 2022 --					
Number of Customers	219,635	7,266	226,901	36,333	2,234	38,567
Use Per Customer (kWh)	11,804	8,528	11,699	57,012	36,361	55,815
Decoupled Rev. per Customer	$938	$671	$929	$4,785	$3,344	$4,702
Allowed Rev. Per Customer	$862	$862	$862	$4,795	$4,795	$4,795
Over (Under) Allowed RPC	$75	($192)	$67	($10)	($1,452)	($94)
Deferred Revenue (*)	($16,548,575)	$1,394,840	($15,153,735)	$364,447	$3,243,230	$3,607,677
	-- 2021 --					
Number of Customers	217,802	6,367	224,169	36,194	1,885	38,078
Use Per Customer (kWh)	11,444	7,945	11,344	57,050	38,582	56,136
Decoupled Rev. Per Customer	$811	$553	$804	$4,436	$3,394	$4,385
Allowed Rev. Per Customer	$787	$787	$787	$4,503	$4,503	$4,503
Over (Under) Allowed RPC	$24	($234)	$17	($67)	($1,109)	($119)
Deferred Revenue (*)	($5,283,617)	$1,492,551	($3,791,066)	$2,428,682	$2,089,408	$4,518,090
	-- 2020 --					
Number of Customers	217,945	3,215	221,160	36,650	900	37,550
Use Per Customer (kWh)	11,145	6,405	11,076	54,230	33,263	53,728
Decoupled Rev. Per Customer	$739	$423	$735	$4,064	$2,947	$4,037
Allowed Rev. Per Customer	$735	$735	$735	$4,380	$4,380	$4,380
Over (Under) Allowed RPC	$4	($313)	($0)	($316)	($1,433)	($343)
Deferred Revenue (*)	($910,276)	$1,004,907	$94,631	$11,574,703	$1,289,651	$12,864,354
* Before interest and revenue related expenses						

Although not always as striking, each of the six comparisons between existing and new customers shown in Table 5-1 (three years and two customer classes) show a similar result as the non-residential customer class in 2022. New customers differ from existing customers in magnitudes that meaningfully impact deferred revenues. These differences in revenue per customer are graphically illustrated in Figure 5-1.

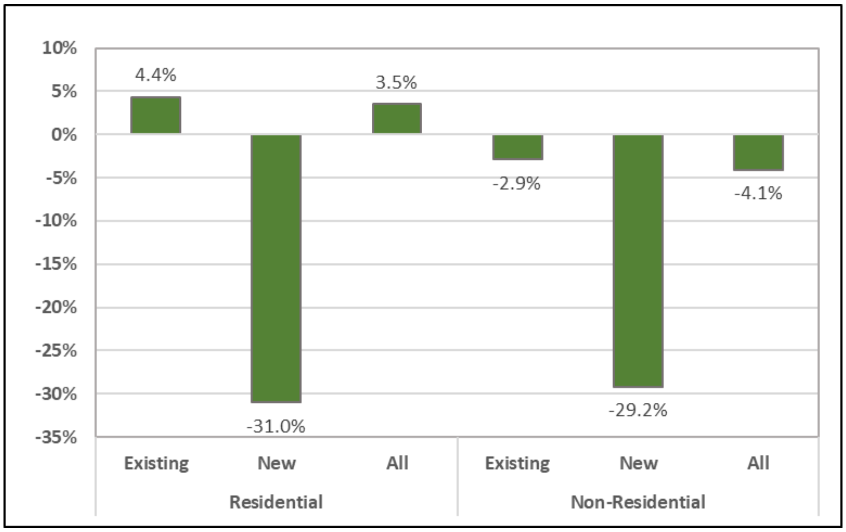


Figure 5-1: Percent Over (Under) Allowed RPC – Electric (2020 – 2022 Average)

The average decoupled revenue per customer over the 2020-2022 period as a percentage of the allowed revenue per customer is shown for both of the decoupled electric customer classes in Figure 5-1. The substantial difference between new and existing customers is clear in the chart. Had new customers been included, electric Residential customers would have received a smaller refund; electric Non-Residential customers would have received a higher charge through application of the decoupling tariff (RS 75).

A comparison of deferral related calculations for existing and new customers is shown for the natural gas system in Table 5-2.[92]

[92] Table 5-2 follows the same structure as Table 5-1.

Table 5-2. Impact of New Customers on Decoupled Deferred Revenue - Natural Gas.

	Residential			Non-Residential		
	Existing	**New**	**All**	**Existing**	**New**	**All**
	-- 2022 --					
Number of Customers	166,593	5,771	172,364	3,274	73	3,347
Use Per Customer (therms)	830	689	825	18,998	25,019	19,129
Decoupled Rev. Per Customer	$419	$358	$417	$4,766	$6,195	$4,797
Allowed Rev. Per Customer	$413	$413	$413	$5,184	$5,184	$5,184
Over (Under) Allowed RPC	$6	($55)	$4	($417)	$1,011	($386)
Deferred Revenue (*)	($1,028,897)	$314,713	($714,184)	$1,366,877	($73,570)	$1,293,308
	-- 2021 --					
Number of Customers	164,302	6,281	170,582	3,142	56	3,198
Use Per Customer (therms)	749	618	744	17,442	22,503	17,530
Decoupled Rev. Per Customer	$346	$291	$344	$4,237	$5,752	$4,263
Allowed Rev. Per Customer	$388	$388	$388	$5,026	$5,026	$5,026
Over (Under) Allowed RPC	($41)	($96)	($43)	($790)	$725	($763)
Deferred Revenue (*)	$6,790,351	$603,447	$7,393,797	$2,481,573	($40,380)	$2,441,193
	-- 2020 --					
Number of Customers	164,450	3,739	168,189	3,119	30	3,149
Use Per Customer (therms)	764	452	757	17,699	16,870	17,691
Decoupled Rev. Per Customer	$337	$201	$334	$4,597	$4,377	$4,595
Allowed Rev. Per Customer	$344	$344	$344	$4,746	$4,746	$4,746
Over (Under) Allowed RPC	($7)	($143)	($10)	($149)	($369)	($151)
Deferred Revenue (*)	$1,218,479	$533,931	$1,752,410	$465,506	$10,958	$476,464
* Before interest and revenue related expenses						

Although the differences are not as pronounced for natural gas as electric, the information in Table 5-2 shows that new residential customers use substantially fewer therms per customer and generate less decoupled revenue per customer than existing customers. Except for 2020, new non-residential customers had substantially higher usage per customer and generated more decoupled revenue per customer than existing customers. Because the number of new customers is small relative to existing customers, the overall impact on deferred revenue is limited but still meaningful. For example, the deferred revenue credit back to residential customers in 2022 would have been reduced by about 30% had new customers been included in the determination of deferred revenue.

Differences in revenue per customer relative to allowed RPC is illustrated in Figure 5-2 for natural gas customer classes.

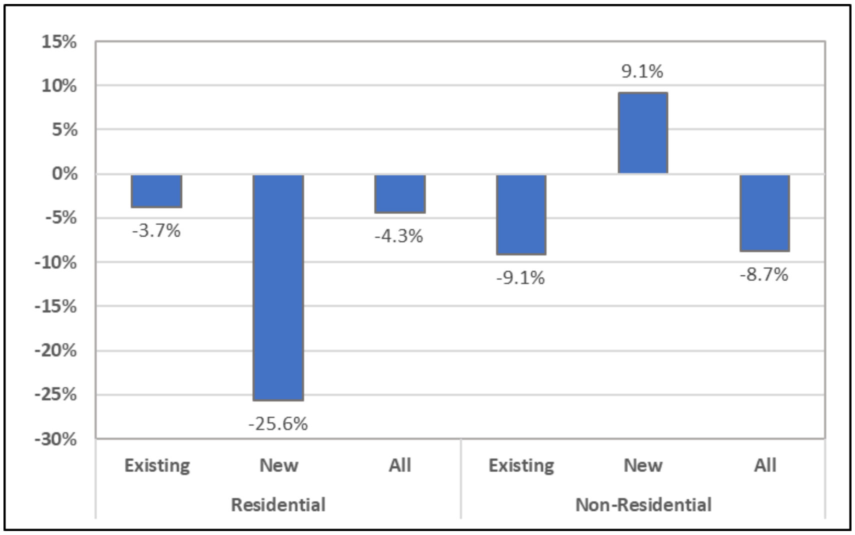


Figure 5-2. Percent Over (Under) Allowed RPC - Natural Gas (2020 - 2022 Average).

The average decoupled revenue per customer over the 2020-2022 period as a percentage of the allowed revenue per customer is shown separately for both Residential and Non-Residential decoupled natural gas customer classes (Figure 5-2). The substantial difference between new and existing customers is clear in the chart. Had new customers been included over the 2020-2022 period, residential customers would have experienced a higher charge, but non-residential customers would have received a lower charge through the decoupling tariff (RS 75).

Summary - New Customers

From 2020 through 2022 Avista's decoupling mechanism applies only to customers on the system during the test year. New customers (operationalized as premises) will not be added to the decoupling mechanism until the next rate case (with a new test year). This raises the question of what the impact of new customers would have been if they had been included in decoupling. The WUTC has directed analysis of this question.

New customers are meaningfully different from existing customers in both use per customer and decoupled (distribution) revenue generated per customer. Although the effect is stronger for electric service, and not as pronounced for natural gas service, new Residential customers use substantially less energy per customer and generate less revenue per customer than existing customers. Because the number of new customers is small relative to existing customers, the overall impact on deferred revenue is limited, but still meaningful.

For electric service, had new customers been included over the 2020-2022 period, electric Residential customers would have received a smaller refund; electric Non-Residential customers would have received a higher charge through application of the decoupling tariff (RS 75).

For natural gas service, had new customers been included over the 2020-2022 period, Residential customers would have experienced a higher charge, but Non-Residential customers would have received a lower charge through the decoupling tariff (RS 175).

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Section 6. Impact of Alternative Definitions of Normal Weather

Normal Weather - Alternative Definitions

Avista uses a rolling 30-year average to define "normal weather". Establishing meteorological normals over a 30-year period has long been a standard used by NOAA and adopted by many industries, including the energy industry. Climate change, however, has resulted in increasing winter and summer temperatures to the point that the traditional 30-year definition of normal needs to be reconsidered. The issue is that a 30-year period may produce inappropriate results when an underlying trend is present. Recognizing this need, one of the decoupling evaluation objectives is to examine the impact of alternative durations in the definition of normal weather. Specifically, as directed by Commission[93], Avista is interested in understanding the impact of using a 20-, 15- and 10-year period for calculating normal weather instead of the historical standard of 30 years (Figure 6-1).[94]

Alternative Weather Calculations

Analysis of using a moving average of weather data shorter than 30 years based on the data gathered by Avista regarding a 30-, 20-, 15-, and 10-year moving average.

Figure 6-1: Four Ways to Calculate Normal Weather.

[93] The Avista calculations use Spokane airport weather data and calculate a moving average. For each new year for which "normal weather" is calculated, the most recent complete data year is used, and the year farthest back is dropped from the data series. Avista's alternative calculations of normal weather are 30-year, 20-year, 15-year and 10-year calculations. Each alternative calculation yields a different answer for normal weather.

[94] The prior decoupling evaluation (2018) included the following recommendation: "Consider a redefinition of normal weather that moves away from the 30-year moving average to a 20-year moving average, and also maintain a moving average indicator for 15 years and 10 years to see how that behaves empirically, since "normal" has become a flow variable and it is rapidly getting warmer as a secular trend." Peach, Hugh., Mark Thompson, and John Joseph, *Avista Decoupling Evaluation, Final Report*. Beaverton, Oregon: H. Gil Peach & Associates, October 1, 2018, p. 10-1. NWEC has recommended that the Commission move to a 20-year moving average and consider the effect of using alternative definitions (DOCKETS UE-190334, UG-190335, UE-190222 (Consolidated) Final Order 09, p. 37. In this order, the Commission found the record insufficient to move to a 20-year standard, but directed study of this question by Avista, and directed review of the Avista results in the current evaluation: "…[W]e reject the proposal to adopt a 20-year moving average of weather data for Avista's decoupling mechanisms at this juncture but determine that the Commission should engage in a broader conversation with stakeholders about the value of moving towards using more recent periods of weather data. To aid in this discussion and to better understand how weather variability affects Avista's decoupling mechanisms, we require Avista to maintain and present data for 30-, 20-, 15-, and 10-year moving averages, and that this design element and data be analyzed by the third-party evaluator." Final Order (Order 09) in Dockets UG-190334, UG-190335, UE-190222 (*consolidated*), March 25, 2020, P. 3.

Climate change requires re-thinking or the 30-year calculation standard. Currently, due to carbon loading of the atmosphere, continually, an amount of solar heat that in prior times was re-radiated into space is retained in the earth's atmosphere, water, and land, so that heat energy is constantly increased on a planetary scale. This has resulted in a trend of increasing winter and summer temperatures to the point that the traditional 30-year definition of "normal weather" must be reconsidered. The issue is that climate change has become strong enough to cause the 30-year calculation to produce an estimate of what weather would have been in the absence of climate change, rather than normal weather. The 30-year calculation produces an estimate of abnormal weather rather than normal weather. In statistical terms, the standard 30-year calculation now produces a biased estimate of projected temperatures.[95]

In the context of decoupling, alternative definitions of normal weather have the potential for impacting deferred revenue from decoupling. Variations result from differences between actual and expected energy use per customer. These can be driven by differences between expected and actual temperatures, energy efficiency improvements, economic changes, and other factors.

Differences in use per customer due to weather are observed when weather deviates from normal. The climate trend in the data is the major source of this variation. Since decoupling has evolved as a practice without taking climate trend into account, statistically speaking, we can initially regard the climate trend as a bias: the observed differences between actual and normal weather are due not only to the typical deviations of actual from normal weather as understood in a calculation with no climate trend, but now also include the climate trend bias embedded in the calculation of normal weather. When the definition of normal weather is biased, decoupling deferrals will also be biased.

Consider a class of customers before the climate trend became quantitatively important. In this hypothetical example, in the absence of a strong climate trend, apparently random changes in weather are the primary physical variable driving the differences between decoupled revenue per customer and allowed revenue per customer.[96] Further assuming that normal weather is accurately defined in the test year, because the primary physical driver is random weather changes, deferred revenues would be expected to average zero over time with above normal fluctuations and below normal fluctuations averaging out.

[95] Because we are moving between frameworks, it can be difficult to grasp the high importance of this change. Reference texts and existing industry algorithms provide methods for calculating "normal weather." However, in a climate change framework, looking for "normal weather" becomes problematic. From about 1935 to 1988, it would have been the right question to ask. Now, going forward, the relevant question is "what will the weather be like for the year we are trying to estimate"? The "new normal weather" would take climate trend (here operationalized as Heating Degree Days) into account. Because the effect has become strong and continues to become stronger, the term "normal" no longer makes sense, unless it includes climate trend. The older calculations (30-year rolling average or the alternative 30-year Typical Meteorological Year) produce an estimate of normal weather which may be useful to adjust revenues for climate change, but it is an estimate of "abnormal weather" – weather as it would have been if the process of climate change were not happening.

[96] Along with any conservation effect, economic effects, and other factors.

If, however, calculated normal weather includes the climate trend, then deferred revenue will be driven by the climate trend and will not average out over time.[97]

In this section we explore in greater depth the impact of alternative definitions of normal weather using data compiled by Avista. Before doing so it is useful to understand how actual weather compared to normal weather over the evaluation period.

30-Year Normal vs. Actual

Comparison of Avista 30-year rolling average Heating Degree Days (HDDs) and Cooling Degree Day (CDDs) to actual HDDs and CDDs is shown in Table 6-1.

Table 6-1. Comparison of Actual to Normal Weather, 2020-2022

	Heating Degree Days			Cooling Degree Days		
	2020	**2021**	**2022**	**2020**	**2021**	**2022**
Actual	6,056	6,038	6,677	556	919	765
Normal	6,514	6,485	6,509	506	524	533
Percentage Difference	-7.0%	-6.9%	2.6%	9.9%	75.4%	43.5%

By the standard used by Avista to calculate normal degree days (30-year historical period updated annually), 2020 and 2021 were warmer heating seasons than normal (fewer heating degree days) and the heating season of 2022 was slightly colder than normal (more heating degree days). Summers were warmer than normal each year.

This is the kind of pattern we would expect when the estimate of normal weather overstates the heating degree days and understates cooling degree days. In 2022, when actual heating degree days exceeded normal, the percentage deviation from normal was far less than the absolute percentage deviation from normal in 2020 and 2021 when actual heating degree were lower than normal.

Since the structure of weather has changed, and continues to change, it is reasonable to conclude that methods of weather adjustment should be modified with reference to actual climate conditions as indicated by the temperature trend, to take changes in structure into

[97] While this simple and hypothetical customer class example allows us to conceptualize the climate trend bias associated with inaccurately defined normal weather, in practice and in the short run, the combined irregularities of actual weather along with changing economic conditions and customer behavior may sometimes swamp the embedded climate trend bias in calculated normal weather.

account.[98] The climate trends, in the form of HDDs and CDDs, have become well defined.

Climate Trends (HDDs and CDDs)

The downward trend for Heating Degree Days (HDD) is shown in Figure 6-2. The upward trend for Cooling Degree Days (CDD) is shown in Figure 6-3.[99] The physical realities underlying these regression lines violate the assumption of steady state relationship among relevant variables over time. The downward slope of the regression line for HDDs (Figure 6-2) means that regardless of decoupling or energy conservation/energy efficiency, customer requirement for heating energy is decreasing. Similarly, in Figure 6-3, the graph shows that, regardless of decoupling or energy conservation, customer need for cooling energy is substantively increasing.

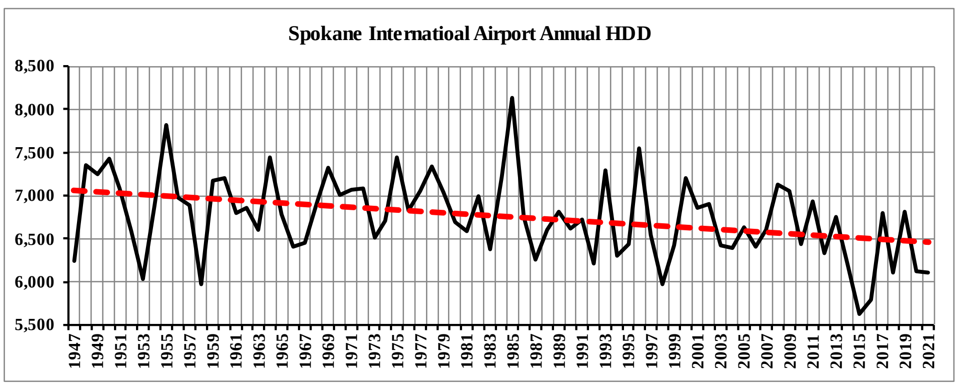

Figure 6-2: Spokane International Airport Annual Heating Degree Days (1947-2021).

[98] "Structure change" refers to a substantive change in the way relationships among variables operate among points in time. When we use time series data and one or more equations to project to a future situation; and if the structure of the relationships modeled by the equation(s) does not change, then the equation(s) can correctly project (predict by approximation) the future value. When structure changes over the years included in an analysis, it is necessary to explicitly take structure change into account. "In prediction under changed structure…predictions are to be made about a process that (because of the structural change) has some feature(s) that have never been observed before: hence the problem is more difficult." Christ, Carl F., *Econometric Models and Methods*. New York, London & Sydney: John Wiley & Sons, Inc., 1966, P. 13. For weather adjustment mechanisms, the primary problem is in two variables, Heating Degree Days (HDD) and Cooling Degree Days (CDD), though additional, more complex weather relationships are also affected.

[99] Spokane International Airport Annual HDD and Annual CDD graphs were provided by Avista.

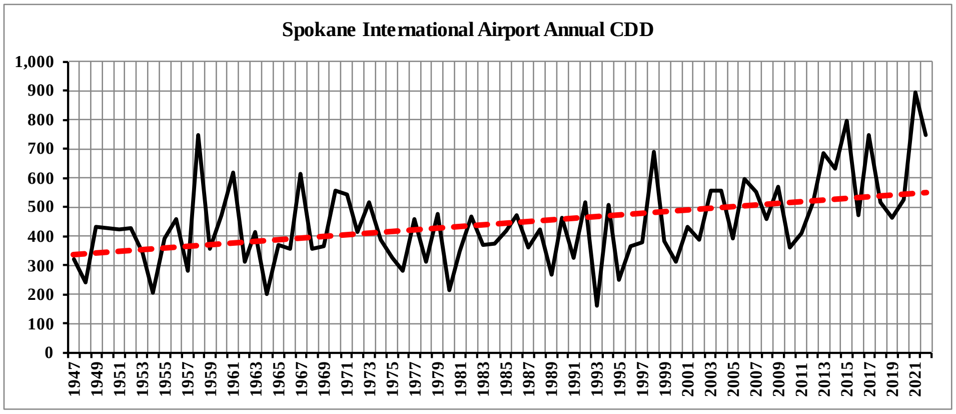

Figure 6-3: Spokane International Airport Annual Cooling Degree Days (1947-2021).

The Peril of Standard Weather Adjustment

Many utilities using the standard weather adjustment mechanism are experiencing problems because their weather adjustment algorithms, which worked well for several decades, may no longer produce reasonable estimates of normal weather. Instead, the weather adjustment algorithm will project a weather estimate much like what weather would have been if there were no climate change.[100] This means that, for Heating Degree Days, the algorithm will operate primarily to adjust customer bills and/or rates upwards to compensate for the revenue loss due to climate change.[101]

Standard weather adjustment algorithms worked well for a situation without climate change (Figure 6-4). In this picture, the weather system is stable; the decreasing HDD trend shown in Figure 6-2 has been removed by detrending the data and the increasing CDD trend shown in Figure 6-3 is not included. This picture is consistent with an understanding of "normal weather," which was a reasonable simplification prior to about 1988.[102] This picture is no longer true.

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[100] Weather could be thought of as an essentially stable system with various occasional perturbations. But not exactly, since the underlying data is a mix of older data, not representative of normal weather when there has been structure change, and recent data, more representative of normal weather under continuing structure change.

[101] Warmer temperatures mean decreasing HDDs, and less need for energy for heating. However, since warmer temperatures occur across all seasons, there is more need for energy for cooling. Since natural gas is used for heating but not for cooling, climate change means increasing loss of revenue for gas. Since electricity is used for both heating and cooling, increased cooling load will, to some extent, offset decreased heating load.

[102] Analysis based on HDD data from Spokane airport (1947-2021) provided by Avista (DR 12 - DR 14). For Figure 6-4, the y-axis value for the blue horizonal line is adjusted from 0 to 7,084 (the trend HDD value of the 1948 data point) to facilitate comparison. All of the data points making up the curve have been detrended. What is left in the data is the cyclical-irregular El Nino Southern Oscillation (ENSO) and irregulars due to weather and all other factors. The HDD trend has been removed. See Frederick E, Dudley J. Cowden, and Sidney Klein, *Applied General Statistics*. Englewood Cliffs, New Jersey: Prentice-Hall, 1967, p. 229.

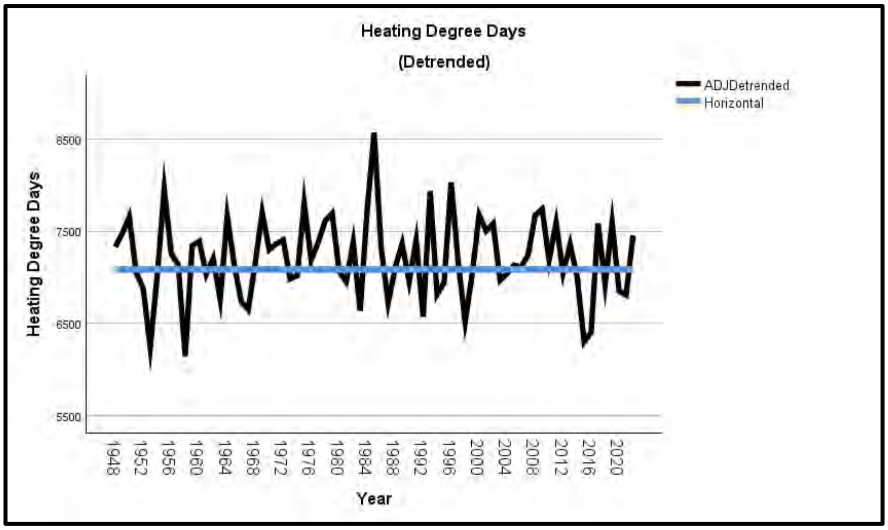

Figure 6-4: Heating Degree Days - Detrended Data – HDD Trend Removed.

As shown in Figure 6-6, which is presented in a format to match Figure 6-4, the structure of weather has changed, and continues to change.[103]

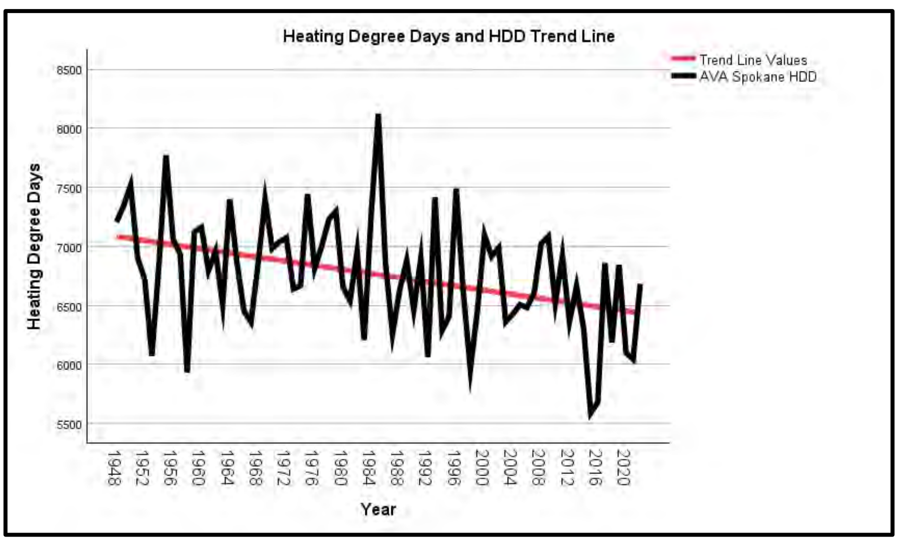

Figure 6-5: Spokane Airport Annual Heating Degree Days (1947-2021).

If the stable system picture (Figure 6-4) were true, then accuracy would not be a problem and the more years included in the analysis, the more precise the result. In the true,

[103] The information in Figure 6-5 is identical to the information in Figure 6-2, only the formatting is different. The derived equation for the (red) HDD climate change trend line in Figure 6-5 is: y= 24,158 – (8.765 * Year).

destabilized system (Figure 6-5), the more years included in the analysis, the lower the standard deviation of the estimated result but, though apparent precision is increased, accuracy is diminished since as more years are included in the calculation, the projected estimate becomes more and more like conditions years ago rather than like conditions as they have become.

The Peril of Real-Time Estimation

For some utilities, the peril in weather adjustment is severe. These utilities apply a standard 30-day or 20-day approach, using a real-time monthly bill adjustment on a per customer basis. Utilities using monthly, per customer, adjustment will likely find their standard method continues to work in summers and winters. However, the “shoulder months” of May and September can be particularly affected.[104] Absurdly high bills are typically associated with customers on billing cycles that 20 or 30 years ago had many days with high Heating Degree Days (HDDs), but the corresponding days of the billing cycle now show zero HHDs and very small numbers of HDDs in a transitional month.[105]

Avista’s calculation method avoids this severe problem since the large decreases in HDDs in May and September due to climate change average out on a yearly basis. Also, Avista’s decoupling adjustment is not a real-time individual bill adjustment. It is a rate adjustment (separately for Residential and Non-Residential) for all customers in a customer group in the following year, rather than individual customer monthly bill adjustments in real time. For Avista, climate structure change is present in the data, but its impact in calculation results is not severe.

Change in Structure of the Weather

Aspects of climate change are shown in Table 6-2.[106] Considered as a system, the earth is now unstable due to increasing retention of heat energy, with heat intensifying, year by year. There are also smaller associated effects in seasonal weather patterns. One of these is that, for North America, the cyclical El Nino Southern Oscillation (ENSO) is becoming stronger, creating a cyclical-irregular effect. There are also irregular changes in components of weather due to shifts in the jet stream and atmospheric rivers, such as incidents of heavy rain, incidents of arctic vortex, increased numbers and strength of

[104] As climate change continues to intensify, the problem with May and September will occur in additional months.
[105] HDDs are used as an example, rather than CDDs since HDD effect sizes are currently much stronger than CDD effect sizes, though this will vary by location. Heating loads are decreasing, leading to decreased sales, so standard weather adjustments are increasing heating bills to compensate. Cooling loads are increasing, so standard weather adjustments are decreasing cooling bill to compensate. Generally natural gas and electric utilities are more focused on HDDs, while water utilities are more concerned with CDDs.
[106] There are various approaches to time series analysis. Table 6-2, following Wesely Clair Mitchell, uses the classification of four elements, trend (T), seasonal (S), cyclical (C), and irregular (I). Our focus here is on the trend. See: See Sections 11, 12, and 22 in Frederick E. Croxton, Cowden, Dudley J., and Klein, Sidney, *Applied General Statistics, Third Edition*. Englewood Cliff, New Jersey: Prentice-Hall, 1967.

hurricanes and tornados, and intense slow-moving heat domes. Here we focus on the climate trend of HDDs, determined by increasing temperatures.

Table 6-2: Climate Effects driving Utility Bills and Rate Adjustments.

Structural Change in Weather driving Utility Bills and Rate Adjustments			
Trend	**Seasonal**	**Cyclical**	**Irregular**
Climate trend: Increased heat, year by year (fewer HHDs, more and more CDDs each year).	Seasonal changes in weather have shifted and continue to shift expected weather by about 1 to 1.5 months so far.	El Nino-Southern Oscillation (ENSO): El Nino and La Nina increasing in strength	Heavy rain, Arctic vortex, More and stronger hurricanes, Shift in pattern and strength of tornados, Flooding, Heat domes.
For the ENSO, see the National Weather Service: What is ENSO? (weather.gov) or the Wikipedia entry at: https://en.wikipedia.org/wiki/El_Ni%C3%B1o%E2%80%93Southern_Oscillation.			

Four Alternative Time Windows for Calculating Normal HDD and CDD

Beginning with reporting for 2020, Avista included estimates of usage and deferred decoupling revenue using alternatives to a 30-year period for calculating normal degree days. Specifically, Avista reports calculations and results using 30-, 20-, 15- and 10- year historical periods for calculating normal weather. Shorter periods improve accuracy but lower precision. Avista alternative time windows for electric calculation are shown in the second column of Table 6-3.

Table 6-3: Weather Related Deferred Revenue with Alternative Normal DD - Electric.

2022 – Electric							
	Years	**Normal**		**Usage Adjustment (kWh)**		**Deferred Decoupled Revenue - Weather Component**	
		HDD	**CDD**	**Residential**	**Non-Residential**	**Residential**	**Non-Residential**
	Col. 1	**Col. 2**	**Col. 3**	**Col. 4**	**Col. 5**	**Col. 6**	**Col. 7**
Row 1	30	6,509	533	(102,767,540)	(31,406,543)	$ (9,188,469)	$ (2,022,240)
Row 2	20	6,401	598	(91,713,224)	(24,843,367)	$ (8,214,575)	$ (1,610,457)
Row 3	15	6,396	617	(83,904,681)	(21,877,433)	$ (7,518,542)	$ (1,420,340)
Row 4	10	6,213	682	(82,437,359)	(16,546,392)	$ (7,405,508)	$ (1,093,695)

In this table, it is clear that moving to shorter historical periods for determining normal degree days lowers the number of HDDs (customers require less heating energy due to warmer heating seasons) and increases the number of CDDs (due to warmer summers and shoulder seasons, customers require more energy to run air conditioning). For electric service, the increased number of CDDs has offsetting impacts, lowering usage for heating but increasing usage for cooling. Table 6-3 shows the net effect for electric customers in 2022. Using the residential customer class as an example, had the test year used a 15-year period for normal, the estimated deferral of decoupled revenue would have been a negative $7.5 million, lower in absolute terms than the negative $9.2 million weather related deferral obtained using the 30-year based normals. A similar result is observed for the non-residential class.

For natural gas, there is no offsetting effect that would stimulate more gas use due to more CDDs, since gas is not used to cool buildings. *This means that as heat increases year after year, the requirement for natural gas decreases.* Avista alternative normal DD calculations are shown for natural gas in Table 6-4. The normal heating and cooling degree days shown in the natural gas table are the same as the electric table because both systems use the same single weather station for reporting weather.

Using the residential customer class as an example, had the test year used a 15-year period to define normal weather, the estimated deferral of decoupled revenue would have been a negative $2.6 million, higher in absolute terms than the negative $1.5 million weather related deferral obtained using the 30-year based normals. A similar result is observed for the non-residential class.

Table 6-4. Weather Related Deferred Revenue with Alternative Normal DD – Natural Gas.

2022 - Natural Gas							
Row	Years	Normal		Usage Adjustment (therms)		Deferred Decoupled Revenue - Weather Component	
		HDD	CDD	Residential	Non-Residential	Residential	Non-Residential
	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7
Row 1	30	6,509	533	(2,666,349)	(841,837)	$ (1,507,517)	$ (250,167)
Row 2	20	6,401	598	(4,718,131)	(1,574,635)	$ (2,572,725)	$ (452,386)
Row 3	15	6,396	617	(4,789,779)	(1,608,894)	$ (2,602,771)	$ (460,800)
Row 4	10	6,213	682	(8,175,340)	(2,792,897)	$ (4,373,457)	$ (789,442)

Note that 2022 had colder than normal weather, even using a rolling 30-year average. Using shorter periods to calculate normal weather pushes the weather impacts in 2022 higher than estimated with 30-year normals. Considering the period 2020 through 2022 together provides an arguably more representative look, averaging the two warmer than normal heating seasons of 2020 and 2021 with the colder than normal heating season of 2022. The cooling seasons are also averaged in the 2020 through 2022 period, all of which were warmer than the 30-year normal. The average weather-related deferrals are shown for electric customers in Figure 6-6.

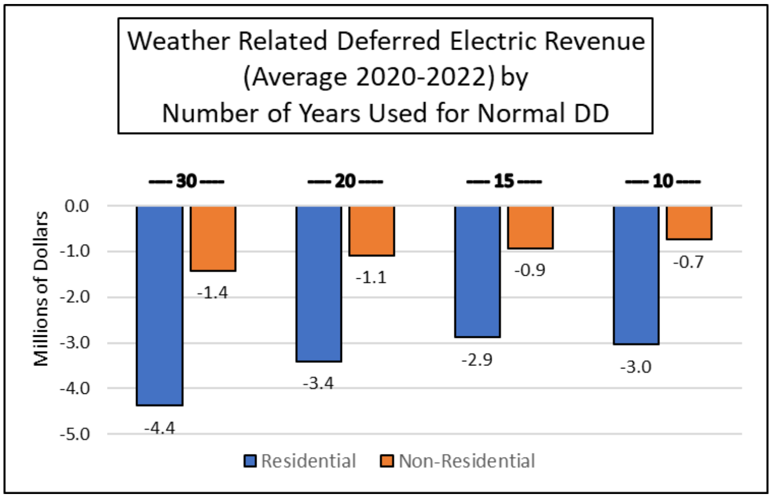

Figure 6-6: Weather Related Deferred Electric Revenue, 2020-2022.

Results shown in Figure 6-7 show that, as expected, the absolute level of deferred electric decoupled revenue declines as the period for calculating normal weather is reduced from 30 years. Similar results are obtained from both the 15- and 10-year estimates of normal weather.

Figure 6-7 shows average weather-related revenue deferrals for natural gas.

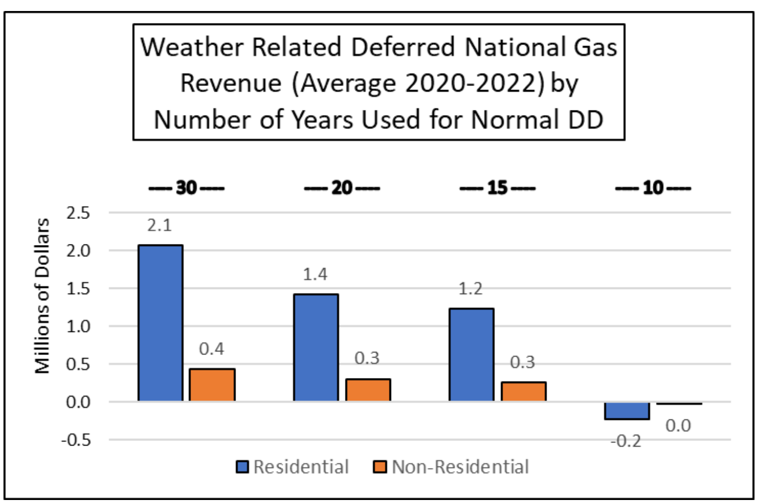

Figure 6-7. Weather Related Deferred Natural Gas Revenue, 2020-2022

Results (Figure 6-7) show that, as expected, the level of deferred natural gas decoupled revenue declines as the period for calculating normal weather is reduced from 30 years. The large difference between the 15- and 10-year results highlights the greater volatility of normal weather based on short periods of data. The 15-year period seems to be the shortest period that still produces stable results over the observed data and the calculations.

The time trend for moving averages of different durations provides visual confirmation of the problem with 5-year and 10-year analysis. The 5-year moving average, as shown by the orange line in Figure 6-8 is highly influenced by the ENSO, and the 10-year moving average (shown by the blue line) also appears to be increasingly influenced by the ENSO, over time.

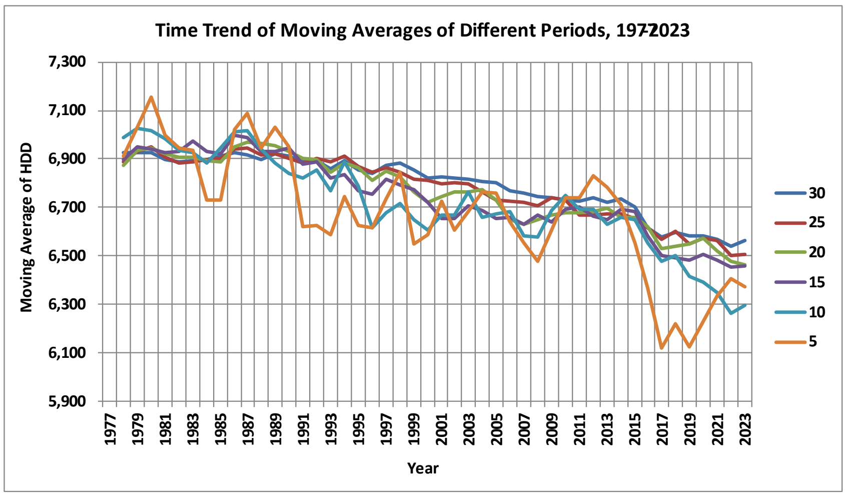

Figure 6-8: Spokane - Moving Average HDD of Different Durations (1977-2023).

Considerations for Weather Calculations

- **Rule out stable system calculation:** Since the system is no longer stable with respect to heat, we need to rule out calculations based on the stable picture (Figure 6-4), even though this was the model in use for doing decoupling weather adjustment and it worked well prior to the emergence of the strong climate change trend. Instead, we must take climate change into account (Figure 6-5).

- **Rule out 10-years:** It might seem that the 10-year moving average would be preferable, since the result would be derived from the ten years just before the year estimated and would best reflect the structure change. However, as noted above, in addition to the trend, an irregular periodic variation occurs - the El Nino

Southern Oscillation (ENSO).[107] Since the ENSO is a cyclical-irregular with a duration of approximately 3 -7 years, it can override the trend in short-period analysis. For this reason, estimation using a 10-year calculation (or less) should be ruled out.

- **Rule out 30-years:** If the weather were stable (if there were no climate change), it would be useful to select the maximum number of years for inclusion in analysis (30 years). This would minimize variation, giving increased precision.[108] The standard deviation is one measure of variation. As shown in Figure 6-9, the standard deviation of the HDD moving average becomes meaningfully smaller as the number of years included in the moving average calculation are increased.

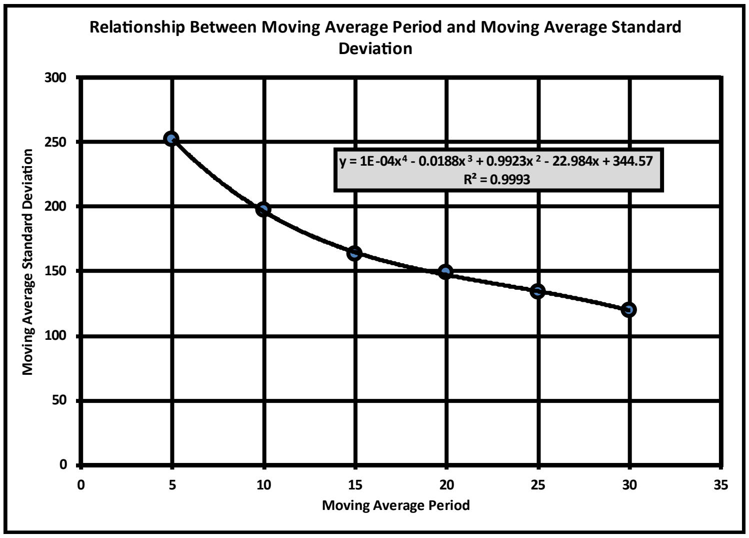

Figure 6-9: Relation of Standard Deviation and Years (Spokane).

However, this approach, while giving the appearance of precision, only provides better precision under the assumption of unchanged structure (Figure 6-4), which is not true. This would be a false precision, meaning that it would create a prediction most closely fitting to a planet without climate change, rather than our actual situation in which the physics of the planet have changed, and continue to change as more and more heat is retained. Precision of the false estimate would be high, but since the estimate would be false, accuracy would diminish with

[107] The oscillation has two periods, El Nino, and La Nina, with a neutral period in between. The full oscillation is irregular and occurs over three to seven years. See: National Weather Service description at: What is ENSO? (weather.gov); Wikipedia: https://en.wikipedia.org/wiki/El_Ni%C3%B1o%E2%80%93Southern_Oscillation.

[108] Precision is a measure of the extent to which repeated measurements agree with one another. Accuracy reflects the proximity of measurements to the true value.

increasing numbers of years included in the calculation. For this reason we rule out the 30-year calculation.

- **Consider the NOAA and climate science precedents.** Although Avista does not use TMY data, NOAA's addition of 15-year time series TMY data to the standard 30-year TMY time series data is an argument for the relative reliability of a 15-year calculation for the analysis. However, as a practical matter, use of both a 30-year calculation and a 15-year calculation is likely to produce a discussion similar to that for a 20-year analysis. Also, we note that climate scientists, in trying to arrive at a best method of calculation to determine the effects of climate change, tend to use a 20-year analysis.[109] With these considerations, the 15-year period seems to be the shortest period that still produces stable results over the observed data and calculations, while the 20-year period is the longest period that does not over-weight the calculation towards weather than can no longer be expected.

Finding: The 15-year period seems to be the shortest period that still produces stable results over the observed data and calculations. The 20-year period is the longest period that does not over-weight the calculation towards weather than can no longer be reasonably be expected.

Figure 6-10: Best Number of Years for Calculation.

What is "Normal Weather"?

What is "normal weather"? Though values are different, each calculation reviewed (30-year, 20-year, 15-year, 10-year) is identical in mathematical operations. Each calculation produces an operational estimate of "normal weather," and each of these estimates drives a different revenue adjustment. We should not use a calculation of ten years of less due to the ENSO cyclical-irregular[110]. For the remaining three operational definitions, precision improves with more years included, but accuracy decreases. These two considerations rule out the 30-year calculation and the 10-year calculation.

However, if it were decided that by "normal weather" we mean developing an estimate based on what weather would have been like if there were no climate change, we would use the 30-year calculation. This would fully compensate the utility for climate-related loss of revenue for the fixed costs included in decoupling. If we want a more moderate adjustment, we could operationalize "normal weather" as 20-years. We should not go below 15 years.

[109] This is a different problem, in that the "pre" reference temperature to which results are compared is taken from the pre-industrial era. However, with that difference, the emerging standard is to use 20-years of time series data in the analysis.
[110] Unless a method can be constructed specifically taking the ENSO into account.

Table 6-5 & Table 6-6 show the ranges of these calculated revenue adjustments for 2022 for electric service and for natural gas.[111]

Table 6-5. Range of Revenue Adjustments - 2022 Electric.

2022 Electric			
Row	**Years**	**Deferred Decoupled Revenue - Weather Component**	
		Residential	**Non-Residential**
Row 1	30	$ (9,188,469)	$ (2,022,240)
Row 2	20	$ (8,214,575)	$ (1,610,457)
Row 3	15	$ (7,518,542)	$ (1,420,340)
Row 4	10	$ (7,405,508)	$ (1,093,695)

Table 6-6. Range of Revenue Adjustments - 2022 Natural Gas.

2022 Natural Gas			
Row	**Years**	**Deferred Decoupled Revenue - Weather Component**	
		Residential	**Non-Residential**
Row 1	30	$ (1,507,517)	$ (250,167)
Row 2	20	$ (2,572,725)	$ (452,386)
Row 3	15	$ (2,602,771)	$ (460,800)
Row 4	10	$ (4,373,457)	$ (789,442)

Decoupling is a Climate Change Adjustment

Weather adjustment associated with decoupling now primarily reflects the strength of climate change, rather than other factors, such as energy conservation and energy efficiency improvements. This is a change. Decoupling would not have been a climate change adjustment prior to about 1988 when the climate effect (here analyzed in the form of Heating Degree Days - HDDs) was weaker. The weather adjustment model for HDDs was designed without recognition of climate change. Decoupling was introduced to remove a potential barrier to energy conservation and energy efficiency, and to improve revenue stability for utilities by providing for a more regular revenue recovery (equivalent to revenue recovery which would occur in the absence of decoupling). With climate change there is a change in the structure of the weather. The climate change

[111] Table 6-5 is a subset of Table 6-3; Table 6-6 is a subset of Table 6-4.

effect is much stronger than the conservation/efficiency effect. While the weather adjustment mechanism associated with decoupling continues to cover energy conservation/energy efficiency and continues to improve revenue stability (for those fixed costs included in decoupling), the major driver now is climate change operationalized as the declining trend of HDDs). Decoupling is, going forward, best understood as a climate change practice, incorporating more timely revenue recovery.[112]

For Avista, however, since the decoupling adjustment is set using a test year, the calculations by Avista and the calculations here do not change bills but provide alternative determinations for the calculation of relative percent of deferred decoupled revenue due to change in the structure of the weather.

Summary – Normal Weather

As directed by the WUTC, Avista has developed four alternative calculations of normal weather, using rolling moving averages of 30-years, 20-years, 15-years, and 10-years. The calculations have no effect on decoupling rates and bills since deferral amounts are set in reference to a test year. However, the calculations permit better understanding of the partition of deferral results between the part driven by weather and the part of deferral driven by all other factors. For this study, the third-party evaluator was directed by the WUTC and by Avista to review Avista data and calculations to help support discussion and better understanding of how weather variability affects Avista's decoupling mechanisms.

Comparison of computed "normal weather" Heating Degree Days (HDDs) and Cooling Degree Days (CDDs) using the standard 30-year rolling average and compared with actuals (Table 6-1) shows two substantive changes:

[112] If decoupling has become more important as a climate change practice rather than as an energy conservation/energy efficiency practice, why were we not aware of this, even in the recent past, as decoupling studies were designed, approved, an analyzed? The answer is in the increasing physical strength of climate effects, which were previously weak, and are strong and becoming stronger, compelling us to change the way we think about decoupling. To understand the kind of change in perception we are experiencing, we can consider studies developed by Ron Westrum, organizational analyst and sociologist who has studied several shifts in social perception of phenomena "hidden in plain sight." For example, Westrum found that medical professionals did not recognize parental or caretaker physical abuse of children until the late 1940s, but now are professionally required to look for and report suspected physical abuse as a medical standard any time injured children are brought for medical attention. Similarly, Westrum has researched the recognition of meteorites, which, although farmers and rural people knew they were real, were not recognized in science until England's Royal Society authorized a formal study. Even though something might be "hidden in plain sight," whether we notice it or not can depend on a variety of factors. We appear to be experiencing a transition from calculation from an energy conservation and efficiency paradigm to primary calculation form a climate physics paradigm. This is discussed further in the appendix.

- HDDs are decreasing. As the planet retains more and more heat, instead of reflecting it back into space, the planet, considered as a system, has become unstable in this regard. The associated HDD graph, with a downward-sloping regression line, shows the decreasing HDDs (Figure 6-2).

- CDDs are increasing. This means, from our human perspective, that more and more cooling is needed to counter the increasing heat. The associated graph, with an upward-sloping regression line, shows the increasing CDDs (Figure 6-3).

These climate change trends are causing severe billing problems for utilities using a real-time monthly bill adjustment for individual customers based on billing cycles. However Avista's method of calculation avoids severe problems since it averages variation across all customers over a year and applies the adjustment as a rate adjustment in the following year, rather than as individual monthly bill adjustment in real-time. However, the problem of ever-increasing heat is now a physical feature of the planet, and the assumption of a stable weather environment does not work.

Avista's results for each of the four calculations of "normal weather" are shown in Table 6-3 for Natural Gas and in Table 6-4 for Electric. These tables show HDDs, CDDs, energy usage adjustment for residential and non-residential, and adjustment in the form deferred decoupled revenue for Residential and Non-Residential customer groups. In examination of these calculations, we find cause to rule out using the alternative of 10-years or less. We also find cause to rule out 30-years. This leaves the 20-year calculation and the 15-year calculation as the preferred alternative.

The 15-year data window is the shortest period that still produces stable results of reasonable accuracy over the observed data and calculations. This choice also coincides with NOAA's choice to add a 15-year TMY as an alternative to its standard 30-year TMY. However, using both the traditional 30-year TMY data and the new 15-Year TMY data is likely to result in discussion that is functionally equivalent to an analysis similar to a 20-year TMY analysis if 20-year TMY data were available. Also, we note that climate scientists, in working on a balanced approach to averaging for defining when a certain increase from the base case occurs (for the separate problem of detecting the year in which the 1.5-degree Celsius target is reached) tend to use 20-year averaging.

Examination of the four alternative operational definitions of normal weather inherently raises the question, "What is normal weather"? Prior to approximately 1988, the problem of change in structure of the weather (operationalized as trend change in Heating Degree Days - HDDs) could reasonably be considered to be below need for consideration. It was not considered in analysis and the topic simply did not rise to the level of serious discussion. At that time, the "deferred decoupled revenue – weather component" was not thought to be an indicator of climate change, and the decoupling mechanism was developed, in part to cover drops in energy usage due to energy conservation/energy efficiency and all other factors by providing more stable revenue recovery.[113] Since at least 1988, the effect size for climate change has become stronger. Until about 1988 "normal weather" could reasonably be considered a projection of a moving average of past weather with inclusion of more years in the analysis leading to increased precision. However, the HDD trend line indicates we need to think though a new definition for "normal weather" that systematically incorporates the trend of ever-increasing planetary heat energy.

The climate trend (operationalized as the HDD trend line) means that projected weather is not a kind of average result, subject to more or less random weather variation, set against a stable background. The 15-year and the 20-year calculations are currently superior to the alternatives.

Deferred decoupled revenue adjustment continues to remove a barrier to more aggressive energy conservation/energy efficiency and continues (for those fixed costs included in decoupling) to improve revenue stability without changing total collections. Now, and going forward the structure of weather has changed, driven by climate change. For weather adjustment, the main driver now is climate change with conservation/energy efficiency secondary. The decoupling weather adjustment should be recognized as primarily a climate change practice to support provision of regular utility revenue in the era of climate change.

[113] Decoupling would recover the same revenue that would have been recovered through rate cases, but recovery would be more stable.

Section 7. Cap Analysis

Avista uses a rolling 30-year average to define "normal weather". Establishing meteorological normals Currently Avista's decoupling tariff has a feature that limits the percent increase in rates due to the annual decoupling adjustment to no more than a 3 percent increase. This feature is described as the decoupling rate cap. The objective in this section is to present analysis of two alternatives to the 3 percent cap, a 5 percent cap and no cap.

The cap feature only applies to the portion of the decoupling adjustment that is greater than zero. In other words, the rate cap does not apply to customer rebates. For example, if the current decoupling rate is negative (a rebate to customers) and the proposed decoupling rate is positive (a customer surcharge) then the 3 percent cap only applies to the increase in rates from zero to the new proposed rate and not to the increase between the current negative rate to the new proposed positive rate. Use of a rate cap to limit the decoupling charge to customers has the impact of extending the time to recover deferred decoupled revenue beyond the time deferred revenue would have been collected without the cap.[114]

> If the current decoupling rate is negative (a rebate to customers) and the proposed decoupling rate is positive (a customer surcharge) then the 3 percent cap only applies to the increase in rates from zero to the new proposed rate and not to the increase between the current negative rate to the new proposed positive rate.

Figure 7-1. How the Cap Works.

Alternative Caps – Electric

Both alternatives to the current 3 percent cap (5 percent cap and no cap) are less restrictive than the current cap. This means that for years when the 3 percent cap did not have a limiting effect on the decoupling rate, the alternatives of 5 percent and no cap would have resulted in the same decoupling rate as the 3 percent cap. Table 7-1 shows what happens when the current decoupling rate adjustment is negative (a rebate to customers), and the proposed decoupling rate adjustment is positive (a customer surcharge). Then the 3 percent cap only applies to the increase in rates from zero to the newly proposed rate and not to the increase between the current negative rate and the new proposed positive rate.

[114] The pace that Avista recovers deferred decoupled revenue from a customer rate class is dependent on the decoupled rate (Rate Schedule 75 for electric and Rate Schedule 175 for natural gas) and the actual units of energy (kWh or therms) delivered to existing customers in that rate class.

Table 7-1shows a summary of decoupling deferral results and decoupling tracker rates for both decoupled electric rate groups over the three decoupling years of this evaluation.

Table 7-1. Deferrals and Decoupling Recovery Rates, 3 Percent Cap - Electric.

Electric							
		Residential Group			**Non-Residential Group**		
	Notes	**2020**	**2021**	**2022**	**2020**	**2021**	**2022**
Summary of Deferred Revenue (1,000 $)							
Deferred revenue		(811)	(5,124)	(16,126)	11,263	2,389	385
Requested recovery	A	(1,112)	(5,801)	(18,646)	14,761	2,748	(1,889)
Customer surcharge (rebate) revenue		(1,112)	(5,801)	(18,646)	14,489	2,748	(1,889)
Carryover deferred revenue		0	0	0	271	0	0
Summary of Decoupling Rate Adjustment							
Decoupling rate (schedule 75) (cents/kWh)	B	(0.045)	(0.234)	(0.725)	0.679	0.132	(0.088)
Percent incremental surcharge (credit)		-3.0%	-2.0%	-4.7%	3.0%	-4.9%	-2.0%
Limited by 3% cap?		No	No	No	Yes	No	No
Notes:							
A: Requested recovery is equal to deferred revenue after adjusting for shared excess earnings (if applicable), deferral balance carryover from prior year (if any), interest, and revenue related expenses.							
B: Decoupling rates Schedule 75 (electric) and Schedule 175 (natural gas) take effect on August 1st of the following year.							

As shown in, the level of deferred revenue used to establish the decoupling rate (schedule 75) in the residential rate group was not limited by the 3 percent cap. This means that had the less restrictive caps of 5 percent and no-cap been in effect during these decoupling years they would have produced the same results as a 3 percent cap for the electric Residential rate group. However, the 3 percent cap was a limiting factor for the electric Non-Residential rate group in 2020. Analysis of the impact of alternative caps is shown for the electric non-residential rate group in Table 7-2.

Table 7-2. Analysis of Alternative Rate Caps – Electric Non-Residential.

		Electric Non-Residential Rate Group *					
		Current 3% Cap			5% Cap Analysis		
		2020	**2021**	**2022**	**2020**	**2021**	**2022**
Summary of Deferred Revenue (1,000 $)							
Row 1	Deferred revenue	11,263	2,389	385	11,263	2,389	385
Row 2	Requested recovery	14,761	2,748	(1,889)	14,788	2,644	(1,889)
Row 3	Customer surcharge (rebate) revenue	14,489	2,748	(1,889)	14,788	2,644	(1,889)
Row 4	Carryover deferred revenue	271	0	0	0	0	0
Summary of Decoupling Rate Adjustment							
Row 5	Decoupling rate (schedule 75) (cents/kWh)	0.679	0.132	(0.088)	0.693	0.127	(0.088)
Row 6	Percent incremental surcharge (credit)	3.0%	-4.6%	-2.0%	3.1%	-4.8%	-2.0%
Row 7	Limited by cap?	Yes	No	No	No	No	No

* The no cap scenario is not shown since it produces the same results as a 5% cap in 2020, 2021 and 2022.

Table 7-2 shows the results of using the 3 percent cap side-by-side with results using a 5 percent cap. Because the 5 percent cap was not reached in 2020-2022 (see Row 6) results of using no-cap are identical to the 5 percent cap results.

Using a 3 percent cap had the result of excluding a relatively small amount ($0.3 million) of the requested recovery of $14.8 million of deferred decoupling revenue from determination of the decoupling rate effective August 1, 2021. The excluded amount resulted in a slightly lower decoupling rate from the 2020 results (effective August 1, 2021) and a slightly higher rate from the 2021 results (effective August 1, 2022) than would have resulted using a 5 percent cap or a no-cap mechanism.

Decoupling rates from 2022 results (effective August 1, 2023) would have been the same using a 3 percent, 5 percent, or no-cap mechanism. As shown in Table 7-2 the percent change in revenue from the decoupling rate over the 2020, 2021 and 2022 decoupling years was 3.0%, -4.6% and -2.0% respectively, using the 3 percent cap compared to 3.1%, -4.8%, and -2.0% respectively had a 5 percent or no-cap mechanism been in place.

Alternative Caps – Natural Gas

Table 7-3 shows a summary of decoupling deferral results and decoupling tracker rates for both decoupled natural gas rate groups over the three decoupling years of this evaluation.

A significant portion of the requested deferral recovery in both rate groups was limited by the 3 percent cap in 2021. The 3 percent cap had no effect on the decoupling results from the 2020 and 2022 decoupling years on either natural gas rate group. Our analysis of the impact of alternative caps is shown for the natural gas residential rate group in Table 7-4.

Table 7-3. Deferrals and Decoupling Recovery Rates, 3 Percent Cap – Natural Gas

Natural Gas							
		Residential Group			**Non-Residential Group**		
	Notes	**2020**	**2021**	**2022**	**2020**	**2021**	**2022**
Summary of Deferred Revenue (1,000 $)							
Deferred revenue		1,174	6,559	(1,069)	445	2,401	1,302
Requested recovery	A	1,256	7,021	802	495	2,574	2,439
Customer surcharge (rebate) revenue		1,256	5,379	802	495	1,680	2,439
Carryover deferred revenue		0	1,643	0	0	894	0
Summary of Decoupling Rate Adjustment							
Decoupling rate (schedule 175) (cents/therm)	B	0.925	3.899	0.587	0.813	2.866	3.987
Percent incremental surcharge (credit)		1.8%	3.0%	-2.5%	0.7%	3.0%	1.2%
Limited by 3% cap?		No	Yes	No	No	Yes	No
Notes:							
A: Requested recovery is equal to deferred revenue after adjusting for shared excess earnings (if applicable), deferral balance carryover from prior year (if any), interest, and revenue related expenses.							
B: Decoupling rates Schedule 75 (electric) and Schedule 175 (natural gas) take effect on August 1st of the following year.							

Table 7-4. Analysis of Alternative Rate Caps – Natural Gas Residential

		Natural Gas Residential Rate Group *					
		Current 3% Cap			5% Cap Analysis		
		2020	**2021**	**2022**	**2020**	**2021**	**2022**
Summary of Deferred Revenue (1,000 $)							
Row 1	Deferred revenue	1,174	6,559	(1,069)	1,174	6,559	(1,069)
Row 2	Requested recovery	1,256	7,021	802	1,256	7,070	(1,076)
Row 3	Customer surcharge (rebate) revenue	1,256	5,379	802	1,256	7,070	(1,076)
Row 4	Carryover deferred revenue	0	1,643	0	0	0	0
Summary of Decoupling Rate Adjustment							
Row 5	Decoupling rate (schedule 175) (cents/therm)	0.925	3.899	0.587	0.925	5.125	(0.788)
Row 6	Percent incremental surcharge (credit)	1.0%	3.0%	-2.5%	1.0%	4.2%	-4.4%
Row 7	Limited by cap?	No	Yes	No	No	No	No
* The no cap scenario is not shown since it produces the same results as a 5% cap in 2020, 2021 and 2022.							

Table 7-4 shows the results of using the 3 percent cap side-by-side with results using a 5 percent cap. Because the 5 percent cap was not reached in 2020, 2021 or 2022 (see Row 6) results of using no-cap are identical to the 5 percent cap results.

Using a 3 percent cap had the 2021 result of excluding $1.6 million of the $7.0 million requested recovery of deferred decoupling revenue from determination of the decoupling rate effective August 1, 2022. The excluded amount resulted in a lower decoupling rate from the 2021 results (effective August 1, 2022) and a higher rate from the 2022 results (effective August 1, 2023) than would have resulted using a 5 percent cap or a non-cap mechanism.

As shown in Table 7-4 the percentage of incremental revenue from the decoupling rate over the 2020, 2021 and 2022 decoupling years was 1.0%, 3.0% and -2.5% respectively, using the 3 percent cap compared to positive 1.0%, positive 4.2%, and a 4.4% decline, respectively, had a 5 percent or no-cap mechanism been in place.

Our analysis of the impact of alternative caps is shown for the natural gas Non-Residential rate group in Table 7-5.

Table 7-5. Analysis of Alternative Rate Caps – Natural Gas Non-Residential.

		Natural Gas Non-Residential Rate Group								
		Current 3% Cap			5% Cap Analysis			No Cap Analysis		
		2020	**2021**	**2022**	**2020**	**2021**	**2022**	**2020**	**2021**	**2022**
Summary of Deferred Revenue (1,000 $)										
Row 1	Deferred revenue	445	2,401	1,302	445	2,401	1,032	445	2,401	1,302
Row 2	Requested recovery	495	2,574	2,439	495	2,596	1,498	495	2,601	1,374
Row 3	Customer surcharge (rebate) revenue	495	1,680	2,439	495	2,483	1,498	495	2,601	1,374
Row 4	Carryover deferred revenue	0	894	0	0	114	0	0	0	0
Summary of Decoupling Rate Adjustment										
Row 5	Decoupling rate (schedule 175) (cents/therm)	0.813	2.866	3.987	0.813	4.235	2.449	0.813	4.436	2.246
Row 6	Percent incremental surcharge (credit)	0.7%	3.0%	1.2%	0.7%	5.0%	-1.9%	0.7%	5.3%	-2.3%
Row 7	Limited by cap?	No	Yes	No	No	Yes	No	No	No	No

The results of the Non-Residential natural gas rate group for the 2021 deferral year were impacted by the 3 percent cap and the 5 percent cap (see Row 6). This rate group is the only one of the three that would have been limited by a 5 percent cap. Roughly a third of the requested 2021 recovery was cleared by the 3 percent cap. A 5 percent cap would have cleared all but about $0.1 million of the requested $2.6 million recovery.

All of the natural gas Non-Residential requested recovery would have been included in the decoupling rate from the 2021 results (effective August 1, 2022) if there would have been no-cap in the Avista decoupling mechanism. Looking at both the decoupling rate (Row 5) and the percent change in revenue from the decoupling rate (Row 6) it is clear that moving from the most restrictive cap on the decoupling rate adjustment (3 percent) to the least restrictive (no cap) results in increasingly more volatile rates and increasingly faster rates of recovery of decoupled deferred revenue. This can be seen in the no-cap analysis which produces the highest decoupling rate (Rate Schedule 175) from 2021 results (4.436 cents/therm; Row 6, Column for 2021) and the lowest decoupling rate from 2022 results (2.246 cents/therm; Row 6, Column for 2022).

Summary – Alternative Caps

The use of a decoupling rate cap on customer surcharges has the advantage of smoothing out rates and the disadvantage of prolonging recovery of decoupled revenue. Raising the rate cap to 5 percent would have allowed for full amortization of decoupled revenue from 2020, 2021 and 2022 decoupling years in the next rate adjustment for each of the four rate groups except the natural gas Non-Residential rate group.

Residential electric customers were not restricted by the 3 percent cap in results from 2020, 2021, or 2022; so less restrictive caps would have had no impact on this rate group over these years. Residential natural gas customers would have had more volatile rates had a 5 percent cap been in place over the three-year evaluation period. At average residential customer usage of sixty-seven therms each month, a 5% cap would have resulted in $0.82 higher monthly residential bills over the August 2022 through July 2023 rate year, which is $9.84 annually, and lower bills over the August 2023 through July 2024 period by equivalent amounts.[115]

Finding: The use of a decoupling rate cap on customer surcharges has the advantage of smoothing out rates and the disadvantage of prolonging revenue recovery. Raising the rate cap to 5% will sometimes increase bills for the next rate year, while lowering bills for the rate year after that. Going to no-Cap provides quickest recovery.

Figure 7-2: Rate Caps.

[115] Average residential customer usage of sixty-seven therms is an Avista reporting standard and not a statistical average produced by our analysis. The increase in bills in the August 2022 through July 2023 rate year followed by lower bills in the next rate year is equivalent but not equal due to interest charges and revenue related expenses.

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Section 8. Analysis of Possible Adverse Impacts

Establishing meteorological normals Decoupling is a purposive reform designed "…to ensure that utilities have a reasonable opportunity to earn the same revenues that they would under conventional regulation, independent of changes in sales volume."[116] This objective, stated in the form of a test, could be considered the "revenue opportunity test." Another goal in regulatory decoupling, beyond meeting the revenue opportunity test, is to remove the inherent management and organizational drive to increase energy sales ("the throughput incentive").

Sometimes, purposive programs have unintended side effects, which may be positive or negative. Here we focus on possible adverse impacts caused by or associated with decoupling (Figure 7-1).

Task 7: Analysis of Possible Adverse Impacts

Identification of any conclusive evidence to suggest that the Mechanisms adversely impacted customer service, distorted price signals for customers resulting in lower participation in conservation programs, or eroded Avista's incentive to control costs and improve efficiency and/or Washington required service quality measures.

Figure 8-1. Identify Adverse Impacts

Are there Adverse Effects?

Both formal learning and lessons of experience teach us that any rationally designed and purposive program may develop unanticipated side effects.[117] No matter how knowledgeable the staff, no matter how skilled the development, no matter how high the degree of

[116] Lazar, Jim, "Examples of Good, Bad, and Ugly Decoupling Mechanisms," presentation to NARUC Symposium: Aligning Regulatory Incentives with Demand-Side Resources. San Francisco, California August 2, 2006 (https://pubs.naruc.org/pub.cfm?id=4AC7A83F-2354-D714-5130-4C68971713CB). Note that this emphasis on keeping revenue opportunity the same as under conventional regulation is both fuel-neutral and neutral with regard to other purposes for engaging regulatory decoupling.

[117] Although the recognition of unintended/unanticipated consequences is currently attributed to Merton, Merton himself notes a deep historic chain of prior writers: "In some one of its numerous forms, the problem of the unanticipated consequences of purposive action has been treated by virtually every substantial contributor to the history of social thought." See: Merton, Robert K, "The Unanticipated Consequences of Purposive Social Action," *American Sociological Review*, Vol. 1, No. 6, December 1936, pp. 894-904. Beyond this, by observation, intelligent animals, for example cats, experience unanticipated consequences, so it is quite likely that, being a phenomenon observed in animals, experiential recognition of unintended consequences is older than human history. This observation of the historically deep experience of unanticipated consequences fits the Darwinian model for social evolution and organizational development. Things happen, we experience reality as different than we imagined, and we evolve and adapt. The social Darwinian model is a central analytic tool of the evolutionary epistemology (selection theory) approach to organizational analysis. Heyes, Cecilia & David L. Hull, eds., *Selection Theory and Social Construction, The Evolutionary Naturalistic Epistemology of Donald T. Campbell*. Albany, New York: State University of New York.

institutional integrity and the degree of social, technical, managerial, and executive insight from which a program springs, any policy reform may have unanticipated and unintended consequences.[118] Utilities are both high-tech and complex systems. In organizational analysis, it is understood that unanticipated and unintended consequences happen in high-tech complex systems.[119]

The high-level question in this section of the evaluation is to determine if there is any conclusive evidence to suggest that the Mechanisms adversely impacted Avista's customer service, created price signals that lowered participation in conservation programs, or eroded Avista's incentive to control costs and improve efficiency and/or Washington required service quality measures.[120]

Following the research questions for this evaluation, we focus on three sub-areas:

- Did decoupling impact Avista's service quality, on the Washington required service quality measures?
- Were there decoupling price signals that resulted in lower participation in conservation programs?
- Did decoupling erode Avista's incentive to control costs and improve efficiency?

Service Quality - Customer Service Measures

Avista implements the State of Washington required Service Quality Indices (SQI) and reliability measures.[121] The existence of this series of yearly reports permits examination of customer service metrics to see if service goals have been met since the beginning of decoupling in 2015 with the first impact of decoupling on energy bills in November 2016 and with the first full year of decoupled bills in 2017. For this study, the data runs through 2022.

[118] Following Donald Campbell, the terms "program" and "reform" are used interchangeably: a new approach or program, such as decoupling – a policy reform effected in governance and institutional practice, is both a program and a reform. Campbell, Donald T., "The Experimenting Society," Pp. 35-68 in Dunn, William N., ed., *The Experimenting Society, Essays in Honor of Donald T. Campbell, Policy Studies Review Annual, Volume 11*. New Brunswick, New Jersey & London: Transaction Publishers, 1998; Dunn, William N., "Reforms as Arguments," Pp. 294-326 in *Knowledge: Creation, Diffusion, Utilization*, Volume 3, Number 3, March 1982; Campbell, Donald T., "Experiments as Arguments," Pp. 327-337 in *Knowledge: Creation, Diffusion, Utilization*, Volume 3, Number 3, March 1982.

[119] The problem of human limits was developed in the 1200's in the systematic philosophic and theological studies of Thomas Acquinas, which contributed to the development of what eventually became scientific method. Today, organizational and policy analysts are aware that high tech and complex organizations may experience unexpected effects, including latent organizational drift and normal accidents. Perrow, Charles, *Normal Accidents*. Princeton, New Jersey: Princeton University Press, 1999; Dekker, Sidney, *Drift into Failure.* Burlington, Vermont & Farnham, Surrey, England: Ashgate Publishing Limited, 2011.

[120] Sometimes side effects are not seen by anyone; sometimes side effects may be anticipated by some parties while the preponderance of parties involved in shaping, managing, and implementing a program may not see a side effect, except retrospectively. In such a case we might say, to use an analytic category developed by organizational, policy, and social scientist Ron Westrum, that the effect was "hidden in plain sight."

[121] The Washington Utilities and Transportation Commission (UTC) required Service Quality Indices are provided by Avista in response to H. Gil Peach & Associates LLC Data Request No. 52 in the prior study, and Data Request No. 30 in this study.

First, we examine Avista Service Quality Indices following decoupling to see if service goals were met, keeping in mind that calendar 2017 is the first year fully within the "after decoupling" time window from a customer perspective. As shown in the tables for 2015 through 2022 good performance on service goals were achieved each year. *There were no negative effects on these SQI indicators. Across all calendar years in this study, SQI results exceeded targets and stayed within a narrow band above target levels.*

The complex nature of the formation of indicator values in terms of context (for example, weather and human behavior) suggests that as a general rule of method, key performance indicators (KPIs) should not be over-interpreted. We expect results on each KPI to dance around from year to year within a reasonably judgmentally assessed neutral bandwidth, without the size or direction of differences conveying meaning. A sense for defining a "neutral band" is developed from practical experience.

Conceptually this "neutral band" is made up of movements in indicators that result from a very large mix of small influences from a large range of factors including both proximate and remote influences. In addition, many of the active factors are likely random. So, performance tables like Table 7-1 through Table 7-8 usually cannot be used to analyze these small differences (positive or negative). Small differences do not provide substantive meaning, unless there is also a pattern.

Though not useful for assessing small differences, KPIs provide a powerful tool that regulators can use to monitor a utility's performance. The primary use of the KPIs is to make achievement or non-achievement of regulatory goals explicit. This is shown, using check boxes in the final columns of Table 8-1Table 1-1: 2020 Development of Electric Decoupled Revenue per Customer. through Table 8-8.

For a regulatory reform, in this case decoupling, a secondary use of KPIs is to determine if there has been a correlated systematic structure of change in KPI results (either a directionally consistent string of positive or negative results by year (regardless of size) or a directionally consistent string of large positive or negative results by year). These results may be positive or negative.

If either a directionally consistent string of small changes or a directionally consistent string of large changes is found, then the question shifts from correlation to possible causation. For example, in Washington it would not be unusual to find that severe weather events or severe weather patterns are the primary cause for change in KPI results. Also, when customer contact or services are outsourced, change can be due to performance of a particular service vendor or replacement by a different service vendor.

Finding: For the Customer Service Measures, we find no directionally consistent set of either small or large changes in this analysis. There are no meaningful patterns of negative effects.

Figure 8-2: Finding: Customer Service Measures.

Table 8-1. 2015 Indicators of Customer Service Quality – Prior Study DR 52.

Customer Service Measures	Benchmark	2015 Performance	Achieved
Percent of customers satisfied with our Contact Center services, based on survey results	At least 90%	96.1%	✓
Percent of customers satisfied with field services, based on survey results	At least 90%	96.8%	✓
Number of complaints to the WUTC per 1,000 customers, per year	Less than 0.40	0.17	✓
Percent of calls answered live within 60 seconds by our Contact Center	At least 80%	80.7%*	✓
Average time from customer call to arrival of field technicians in response to electric system emergencies, per year	No more than 80 minutes	44 Minutes	✓
Average time from customer call to arrival of field technicians in response to natural gas system emergencies, per year	No more than 55 minutes	51 Minutes	✓

* Results for 2015 on percent of calls answered live within 60 seconds by the Avista Contact Center include all calls received for the year, including the nearly 56,000 calls answered during the November Windstorm event from November 17 through November 27, 2015.

Table 8-2. 2016 Indicators of Customer Service Quality – Prior Study DR 52.

Customer Service Measures	Benchmark	2016 Performance	Achieved
Percent of customers satisfied with our Contact Center services, based on survey results	At least 90%	92.7%	✓
Percent of customers satisfied with field services, based on survey results	At least 90%	94.7%	✓
Number of complaints to the WUTC per 1,000 customers, per year	Less than 0.40	0.25	✓
Percent of calls answered live within 60 seconds by our Contact Center	At least 80%	81.7%	✓
Average time from customer call to arrival of field technicians in response to electric system emergencies, per year	No more than 80 minutes	39.3 Minutes	✓
Average time from customer call to arrival of field technicians in response to natural gas system emergencies, per year	No more than 55 minutes	48.4 Minutes	✓

Table 8-3. 2017 Indicators of Customer Service Quality – Prior Study DR 52.

Customer Service Measures	**Benchmark**	**2017 Performance**	**Achieved**
Percent of customers satisfied with our Contact Center services, based on survey results	At least 90%	93.6%	✓
Percent of customers satisfied with field services, based on survey results	At least 90%	95.2%	✓
Number of complaints to the WUTC per 1,000 customers, per year	Less than 0.40	0.16	✓
Percent of calls answered live within 60 seconds by our Contact Center	At least 80%	81.5%	✓
Average time from customer call to arrival of field technicians in response to electric system emergencies, per year	No more than 80 minutes	39.9 Minutes	✓
Average time from customer call to arrival of field technicians in response to natural gas system emergencies, per year	No more than 55 minutes	50.29 Minutes	✓

Table 8-4: 2018 Indicators of Customer Service Quality - Current DR 30.

Customer Service Measures	**Benchmark**	**2018 Performance**	**Achieved**
Percent of customers satisfied with our Contact Center services, based on survey results	At least 90%	96%	✓
Percent of customers satisfied with field services, based on survey results	At least 90%	97%	✓
Number of complaints to the WUTC per 1,000 customers, per year	Less than 0.40	0.11	✓
Percent of calls answered live within 60 seconds by our Contact Center	At least 80%	81.5%	✓
Average time from customer call to arrival of field technicians in response to electric system emergencies, per year	No more than 80 minutes	39.9 Minutes	✓
Average time from customer call to arrival of field technicians in response to natural gas system emergencies, per year	No more than 55 minutes	42 Minutes	✓

Table 8-5: 2019 Indicators of Customer Service Quality - Current DR 30.

Customer Service Measures	Benchmark	2019 Performance	Achieved
Percent of customers satisfied with our Contact Center services, based on survey results	At least 90%	94.4%	✓
Percent of customers satisfied with field services, based on survey results	At least 90%	94.4%	✓
Number of complaints to the WUTC per 1,000 customers, per year	Less than 0.40	0.13	✓
Percent of calls answered live within 60 seconds by our Contact Center	At least 80%	80.7%	✓
Average time from customer call to arrival of field technicians in response to electric system emergencies, per year	No more than 80 minutes	44.3 Minutes	✓
Average time from customer call to arrival of field technicians in response to natural gas system emergencies, per year	No more than 55 minutes	43 Minutes	✓

Table 8-6: 2020 Indicators of Customer Service Quality - Current DR 30.

Customer Service Measures	Benchmark	2020 Performance	Achieved
Percent of customers satisfied with our Contact Center services, based on survey results	At least 90%	93.6%	✓
Percent of customers satisfied with field services, based on survey results	At least 90%	95.2%	✓
Number of complaints to the WUTC per 1,000 customers, per year	Less than 0.40	0.16	✓
Percent of calls answered live within 60 seconds by our Contact Center	At least 80%	81.5%	✓
Average time from customer call to arrival of field technicians in response to electric system emergencies, per year	No more than 80 minutes	39.9 Minutes	✓
Average time from customer call to arrival of field technicians in response to natural gas system emergencies, per year	No more than 55 minutes	50.29 Minutes	✓

Table 8-7: 2021 Indicators of Customer Service Quality - Current DR 30.

Customer Service Measures	Benchmark	2021 Performance	Achieved
Percent of customers satisfied with our Contact Center services, based on survey results	At least 90%	96%	✓
Percent of customers satisfied with field services, based on survey results	At least 90%	96%	✓
Number of complaints to the WUTC per 1,000 customers, per year	Less than 0.40	0.03	✓
Percent of calls answered live within 60 seconds by our Contact Center	At least 80%	86%	✓
Average time from customer call to arrival of field technicians in response to electric system emergencies, per year	No more than 80 minutes	53 Minutes	✓
Average time from customer call to arrival of field technicians in response to natural gas system emergencies, per year	No more than 55 minutes	49 Minutes	✓

Table 8-8: 2022 Indicators of Customer Service Quality - Current DR 30.

Customer Service Measures	Benchmark	2022 Performance	Achieved
Percent of customers satisfied with our Contact Center services, based on survey results	At least 90%	97%	✓
Percent of customers satisfied with field services, based on survey results	At least 90%	97%	✓
Number of complaints to the WUTC per 1,000 customers, per year	Less than 0.40	0.05	✓
Percent of calls answered live within 60 seconds by our Contact Center	At least 80%	81%	✓
Average time from customer call to arrival of field technicians in response to electric system emergencies, per year	No more than 80 minutes	52 Minutes	✓
Average time from customer call to arrival of field technicians in response to natural gas system emergencies, per year	No more than 55 minutes	48 Minutes	✓

Service Quality – Electric System Service Quality Indices

For electrical reliability, there are two SQI measures (Table 8-9). The System Average Interruption Frequency Index, SAIFI, indicates the *frequency* of long-term (greater than five minutes) service interruptions. The System Average Interruption Duration Index, SAIDI measures the *duration* of long-term (greater than five minutes) service interruptions. For both measures, the smaller the size of the indicator result, the better. As shown in the table, values of both indicators vary from year to year. The highest values for both occur in 2017, the first full post decoupling year and the lowest values for both occur in 2018. There is no indication of a meaningful change in either SAIFI or SAIDI. It would be necessary to see a pattern before drawing a systematic conclusion (negative or positive). The SAIFI graph is shown in Figure 8-4. The SAIDI graph is shown in Figure 8-5.

Table 8-9: Indicators of Electric Service Reliability – Prior DR 52, Current DR 30.

Electric System Reliability							
Year		**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
SAIFI	Frequency of Non-Major-Storm Power Interruptions/Year/Customer	1.14	1.05	1.11	1.05	0.86	1.2
SAIDI	Length of Power Outage/Year/Customer (minutes)	138	138	139	163	133	183
Year		**2018**	**2019**	**2020**	**2021**	**2022**	
SAIFI	Frequency of Non-Major-Storm Power Interruptions/Year/Customer	0.81	0.94	0.89	1.24	0.92	
SAIDI	Length of Power Outage/Year/Customer (minutes)	126	137	132	164	146	

Note: The System Average Interruption Frequency Index or "SAIFI" is the average number of sustained interruptions (outages) per customer for the year.

Note: The System Average Interruption Duration Index or "SAIDI" is the average duration of sustained interruptions (outages) per customer for the year (measured in minutes).

With reference to understanding normal fluctuation of SAIFI and SAIDI, Avista notes that "approximately two-thirds of the utility's system performance each year is subject to random forces such as weather patterns and storms, or other random events such as an outage caused by a car striking a pole, which factors are generally beyond the control of the utility. Consequently, there is a natural variation in results (both up and down) from year to year, due largely to the interaction of these random factors. The "direction" of the annual results and the magnitude of the variation generally reflects the combination of the frequency and magnitude of weather-related events, the contribution of other randomly occurring factors, as well as the effect of standardized adjustments made to the yearly results based on “major event days” [122]

Finding: *There is no adverse effect evident for Electric System Reliability.*

Figure 8-3: Finding: Electric Reliability.

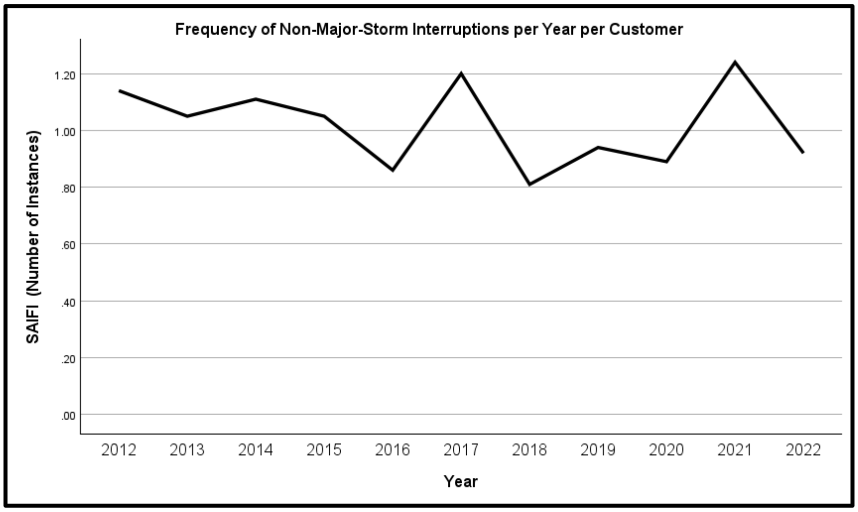

Figure 8-4: SAIFI.

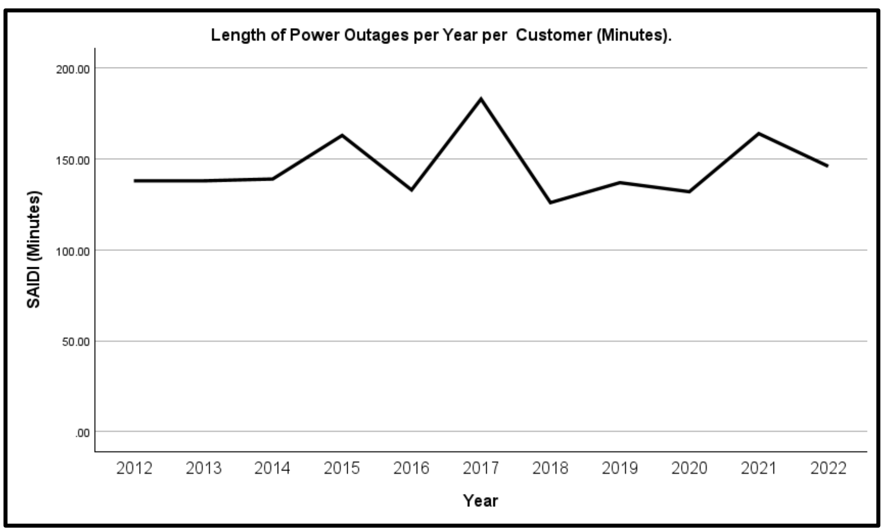

Figure 8-5: SAIDI

[122] Response to prior study DR 080, citing from pages 53-47 of Avista’s Customer Service Quality and Electric System Reliability report for 2017.

Service Quality – Performance Guarantees

Beginning January 1, 2016, Avista introduced a new set of performance indicators called "performance guarantees". These new indicators can also be considered a very visible tool to motivate Washington staff.[123] There are seven specific performance guarantees. Missing the goal for performance on a guarantee results in a payment of a fifty-dollar ($50) bill credit to affected customers.[124]

As shown in Table 8-10 through Table 8-16, Avista's performance on these indicators is very good.[125]

Table 8-10: 2016 Customer Service Guarantees - Prior DR52.

Customer Service Guarantee	Successful	Missed	$ Paid
Keeping Our Electric and Natural Gas Service Appointments scheduled with our customers	1,477	10	$500
Restore service within 24 hours of a customer reporting an outage (excluding major storm events)	26,344	1	$50
Turn on power within a business day of receiving the request	3,380	3	$150
Provide a cost estimate for new electric or natural gas service within 10 business days of receiving the request	5,024	0	$0
Investigate and respond to a billing inquiry within 10 business days if unable to answer a question on first contact	1,760	0	$0
Investigate a reported meter problem or conduct a meter test and report the results within 20 business days	309	2	$100
Notify customers at least 24 hours in advance of a planned power outage lasting longer than 5 minutes	30,336	349	$17,450
Totals	**68,630**	**365**	**$18,250**
	Success Rate: 99.5%		

[123] See: Response to prior study Data Request 081 and: https://www.myavista.com/about-us/contact-us/customer-service-guarantees.

[124] Subject to conditions. There is no payment if a customer cancels or misses an appointment or if the Company reschedules an appointment with at least 24-hours' notice; or, if there is a major weather event that impacts a large number of customers or lasts for a longer period of time, such as a major snow, ice, or wind storm; or, if there is an action or default by someone other an Avista employee or outside of Avista's control; or, if construction is required before service can be energized, evidence that all required government inspections have been satisfied has not been received by Avista, required payments to Avista have not been received, or service has been disconnected for non-payment or there has been theft/diversion of electric service; or, when power is interrupted for less than five minutes, power is interrupted because of work on a meter, or the safety of the public or of Avista employees or the imminent failure of Avista equipment was a factor causing the interruption in service.

[125] For Table 8-10 through Table 8-16 the Success Rate is computed as [Successful/ (Successful + Missed)] and expressed as a percentage in the last row of each table.

Table 8-11. 2017 Customer Service Guarantees - Prior DR 52.

Customer Service Guarantee	Successful	Missed	$ Paid
Electric and natural gas service appointments	1,584	11	$550
Electric outage restoration within 24 hours of notification from customer, excluding major storm events	30,669	23	$1,150
Switch on power within a business day of request	9,557	0	$0
Provide cost estimate for new electric or natural gas service within 10 business days	3,929	0	$0
Investigate and respond to billing inquiries within 10 business days	1,623	0	$0
Investigate customer-reported problems with a meter, or conduct a meter test, and report results within 20 business days	1,082	1	$50
Provide notification at least 24 hours in advance of disconnecting service for scheduled electric interruptions	17,079	115	$5,750
Totals	**65,523**	**150**	**$7500**
	Success Rate: 99.8%		

Table 8-12. 2018 Customer Service Guarantees - Current DR 30.

Customer Service Guarantee	Successful	Missed	$ Paid
Electric and natural gas service appointments	2,216	5	$250
Electric outage restoration within 24 hours of notification from customer, excluding major storm events	4,661	11	$550
Switch on power within a business day of request	7,997	1	$50
Provide cost estimate for new electric or natural gas supply within 10 business days	2,356	0	$0
Investigate and respond to billing inquiries within 10 business days	990	1	$50
Investigate customer-reported problems with a meter, or conduct a meter test, and report results within 20 business days	741	3	$150
Provide notification at least 24 hours in advance of disconnecting service for scheduled electric interruptions	42,014	298	$14,900
Totals	**60,975**	**319**	**$15,950**
	Success Rate: 99.5%		

Table 8-13. 2019 Customer Service Guarantees - Current DR 30.

Customer Service Guarantee	Successful	Missed	$ Paid
Electric & Natural Gas service appointments	$2,774	31	$1550
Electric outage restoration within 24 hours of notification from customer, excluding major events	39,687	16	$800
Switch on power within a business day of receiving the request	5,557	2	$100
Provide cost estimate for new electric or natural gas supply within 10 business days	1,824	0	$0
Investigate and respond to billing inquiries within 10 business days	911	0	$0
Investigate customer-reported problems with a meter, or conduct a meter test, and report results within 20 business days	844	4	$200
Provide notification at least 24 hours in advance of disconnecting service for scheduled electric interruptions	22,092	125	$6,250
Totals	**73,689**	**178**	**$8,900**
	Success Rate: 99.8%		

Table 8-14. 2020 Customer Service Guarantees - Current DR 30.

Customer Service Guarantee	Successful	Missed	$ Paid
Electric & Natural Gas service appointments	2,776	8	$400
Electric outage restoration within 24 hours of notification from customer, excluding major events	44,813	0	$0
Switch on power within a business day of receiving the request	1,024	1	$50
Provide cost estimate for new electric or natural gas supply within 10 business days	1,446	0	$0
Investigate and respond to billing inquiries within 10 business days	1,027	0	$0
Investigate customer-reported meter problem or conduct a meter test and report the results within 20 business days	448	9	$450
Provide notification at least 24 hours in advance of disconnecting service for scheduled electric interruptions	22,101	615	$30,750
Totals	**73,635**	**633**	**$31,650**
	Success Rate: 99.1%		

Table 8-15. 2021 Customer Service Guarantees - Current DR 30.

Customer Service Guarantee	Successful	Missed	$ Paid
Electric & Natural Gas service appointments	3,171	53	$2,650
Electric outage restoration within 24 hours of notification from customer, excluding major events	50,031	6	$300
Switch on power within a business day of receiving the request	474	0	$0
Provide cost estimate for new electric or natural gas supply within 10 business days	1,697	0	$0
Investigate and respond to billing inquiries within 10 business days	824	0	$0
Investigate customer-reported meter problem or conduct a meter test and report the results within 20 business days	355	3	$150
Provide notification at least 24 hours in advance of disconnecting service for scheduled electric interruptions	30,140	143	$7,150
Totals	**89,692**	**205**	**$10,250**
	Success Rate: 99.8%		

Table 8-16. 2022 Customer Service Guarantees - Current DR 30.

Customer Service Guarantee	Successful	Missed	$ Paid
Electric & Natural Gas service appointments	2,896	16	$800
Electric outage restoration within 24 hours of notification from customer, excluding major events	25,337	136	$6,800
Switch on power within a business day of receiving the request	503	1	$50
Provide cost estimate for new electric or natural gas supply within 10 business days	1,328	0	$0
Investigate and respond to billing inquiries within 10 business days	1,042	0	0
Investigate customer-reported meter problem or conduct a meter test and report the results within 20 business days	526	4	$200
Provide notification at least 24 hours in advance of disconnecting service for scheduled electric interruptions	27,155	645	$32,250
Totals	**58,787**	**802**	**$40,100**
	Success Rate: 98.7%		

Table 8-17: Summary: Customer Service Guarantees.

Customer Service Guarantees			
Year	**Successful**	**Missed**	**Success Rate**
2016	68,630	365	99.5%
2017	65,523	150	99.8%
2018	60,975	319	99.5%
2019	73,689	178	99.8%
2020	73,635	633	99.1%
2021	89,692	205	99.8%
2022	58,787	802	98.7%
Average			99.5%

Finding: Avista's success rate for Customer Service Guarantees from 2016-2022 averages 99.5%.

Figure 8-6: Finding: Customers Service Guarantees

Price Signals and Conservation Participation

Determination of the revenue requirement associated with fixed costs is a step in the process of developing a cost-of-service analysis. Cost-of-service analysis is a separate form of analysis that occurs independent of the form of recovery. When recovery occurs through decoupling, the decoupling mechanism recovers selected fixed costs annually, and balances any under-recovery or over-recovery annually. Decoupling does not change the overall amount of fixed costs to be recovered. It changes the timing of recovery and reduces volatility by recovering a set of selected fixed costs not already recovered from volumetric charges. These amounts are recovered in small yearly increments.[126]

With or without decoupling, once established as a revenue requirement, the established fixed cost is allocated to customer groups. Projected recovery involves construction of planning targets (projections based on experience). In decoupling, selected fixed costs are either recovered in the volumetric charge (if energy usage matches planned energy usage); or if there is under-recovery, are programmed to be recovered through an adjustment in volumetric rates

[126] The more frequent yearly rate effect with decoupling should sum to the (theoretical) less frequent aggregated rate recovery impact (without decoupling) over a set of rate cases.

in the following rate year. The amount of recovery to be collected is subject to certain control tools, including the three percent (3%) cap on the amount to be recovered in any one year. The amount larger than the cap is then rolled forward, with interest, to be recovered in a second forward rate year. The decoupling mechanism is balanced; any over-recovery is refunded through a reduction in volumetric rates in the following rate year.[127] The decoupling allocation of fixed costs for a customer group is based on the group's actual energy use in relation to the group's projected energy use.

For utilities in general with or without decoupling) some fixed costs are recovered as fixed costs through the customer charge, and other fixed costs are recovered in volumetric revenue, that is, for the cost per unit of energy. In Avista's decoupling, two separate time windows are used: a *measurement time window*, during which the data for decoupling adjustment for the next implementation time window is collected; and the next rate year, the time window for which the rate adjustment is applied. In Avista's decoupling, the measurement time windows are calendar years. When, during a measurement window calendar year, a customer group decreases energy usage so that the average usage for the group falls below the planning projection for that group for that year, the decoupling adjustment automatically makes up the lost revenue in the next rate year by requiring an increase in the group's volumetric cost per unit (cost per kWh or cost per therm). Conversely, if in a measurement time window calendar-year the average usage for a group exceeds the planning projection, the mechanism will require a reduction in unit cost for the next 12-month implementation time window (rate year).

Given the decoupling price signals observed, did decoupling price signals influence energy conservation effort?

For electric customers, the decoupling price signal (as a percentage of average bill) is shown for Residential in Table 8-18: Residential Electric Decoupling Signal. and for Non-Residential in Table 8-19: Non-Residential Electric Decoupling Signal. Price signals for rebates to customers, or neutral are shown in light blue; price signals in the direction of revenue recovery for the company are shown in yellow.

Table 8-18: Residential Electric Decoupling Signal.

	Electric Residential Group				
	2018	**2019**	**2020**	**2021**	**2022**
Decoupling Price Signal	4.3%	(0.4%)	(3.0%)	(2.0%)	(4.7%)
Limited by 3% cap?	Yes	No	No	No	No

[127] There is no cap on payments to customers.

Table 8-19: Non-Residential Electric Decoupling Signal.

	Electric Non-Residential Group				
	2018	2019	2020	2021	2022
Decoupling Price Signal	3.0%	0.0%	3.0%	(4.9%)	(2.0%)
Limited by 3% cap?	Yes	No	Yes	No	No

For natural gas customers, the decoupling signal as a percentage of average bill is shown in Table 8-20 for Residential customers and in Table 8-21 for Non-Residential customers.

Table 8-20: Residential Natural Gas Decoupling Signal.

	Natural Gas Residential Group				
	2018	2019	2020	2021	2022
Decoupling Signal	4.2%	(1.2%)	1.8%	3.0%	(2.5%)
Limited by 3% cap?	No	No	No	Yes	No

Table 8-21: Non-Residential Natural Gas Decoupling Signal.

	Natural Gas Non-Residential Group				
	2018	2019	2020	2021	2022
Decoupling Signal	2.2%	(2.2%)	0.7%	(3.0%)	(1.2%)
Limited by 3% cap?	No	No	No	Yes	No

As recorded in these tables, most of the decoupling price signals for both electric and natural gas were in the direction of customer rebates. These would not be expected to influence customer energy conservation efforts. The price signals for increasing return to the utility were interspersed with these signals in the direction of the customer. All of the price signals were small enough to likely be below any threshold of perception to influence energy conservation effort either one way or the other. Through 2022, decoupling is operating as expected (as planned) and is not presenting price signals that would adversely affect conservation.

GAAP Accounting

We note that sustained or snowballing deferral can have an impact on GAAP accounting, which requires that revenues be recovered within two years.[128] Avista refers to decoupling deferrals that go unreported in revenue due to GAAP accounting rules as contra-decoupling deferrals. Contra-decoupling deferrals were recorded for natural gas in both 2015 and 2016. Patterns like those in Table 8-18 through Table 8-21 do not indicate a tendency for sustained or snowballing deferral.

[128] In the Response to Prior Study Data Request 064, Avista notes that “GAAP reporting rules do not allow for recognition of revenues from a mechanism like decoupling in excess of the amount expected to be recovered within 24 months of the end of the deferral period.”

Cost Control and Operational Efficiency

Since decoupling is designed to produce recovery of selected fixed costs equal to recovery that would occur through rate cases if there were no recovery, we would expect no adverse effect of decoupling on the utility's incentive to control costs.

Avista's perspective is that "[t]he adoption of decoupling has not resulted in a change of efforts by the Company to operate efficiently, rather the Company has, prior to decoupling, and with decoupling, strived to be as efficient as possible while at the same time providing safe and reliable service for our customers."[129] Further, the Company points out that "[t]he decoupling mechanisms provide recovery of fixed costs, on a revenue per customer basis, that were approved by the Commission in a prior general rate case for recovery. To the extent those fixed costs increase, or escalate, over time, the mechanisms do not provide for recovery of the change in costs above the approved level already embedded in the allowed revenue per customer. The Company continues to bear the risk of changes in costs between general rate cases, and therefore must (and has) manage the business in a prudent manner."[130]

By removing the focus on sales, decoupling may permit utility executive management to focus more effectively on other goals. Because cost recovery proceeds in a decoupled utility following a target revenue requirement that has already been projected in a commission proceeding, costs have been anticipated. A focus on cost control can function within this *already established revenue requirement* to improve earnings. This does not mean that current cost-control projects derive directly from decoupling. Avista has continually developed cost-control projects prior to decoupling. However, with decoupling, Avista *cannot* increase profits by increasing sales but can *only positively improve profits by improving cost control and operational efficiency*. The nature of this relationship under decoupling has been described by the Regulatory Assistance Project (Figure 7-2).

> Decoupling does not guarantee utilities a level of earnings, only an assurance of a level of revenue. If the utility reduces costs, it increases earnings, just as it would under traditional regulation. Also, because the utility cannot increase profits by increasing sales, improved operational efficiency is the only means by which it can boost profits.
>
> Source: The Regulatory Assistance Project, Revenue Regulation & Decoupling: A Guide to Theory and Application. Montpelier, Vermont: Regulatory Assistance Project, June 2011, P. 45.

Figure 8-7. Increasing Earnings in a Decoupled Utility (RAP)

[129] Response to Prior DR 063.
[130] Response to Prior DR 063.

The Company has provided examples of ways that it is lowering operational expenses to benefit customers:[131] Each of these changes was introduced in 2020 or prior and was included in the prior study. There are no additions for 2020 through 2022, however, each change remains in effect.[132]

Careful evaluation of each component of overall compensation.

We note that utilities typically re-evaluate each element of overall compensation yearly or every few years. This cost-control tool is likely the same focus that would be implemented with or without decoupling. Whether or not deriving specifically or in part from decoupling in the current context, this is an approach to reducing operational expenses.

A current hiring restriction which requires approval of the hiring manager, as well as the President of Avista, the CFO, the CEO and the Sr. VP for Human Resources for all replacement or new hire positions.

This step is not a standard cost-control tool and may or may not be related to the influence of decoupling. It is unusual for a utility to implement this level of review for all replacement or new hire positions, although utilities may find it prudent to implement controls from time to time or (alternatively) to open up for new hiring in certain areas or for certain scarce special skills from time to time. Whether or not deriving specifically or in part from decoupling in the current context, this is an approach to control operational expenses.

Effective January 1, 2014, Avista no longer contributes toward medical insurance premiums for the retiree medical plan.

Beginning January 1, 2020, a new calculation method will shift more expenses to retirees.

To reduce the number of medical office visits, the Company is providing web and phone-based 24/7 telemedicine and there is an on-site clinic.

Beginning in 2017, the Company offered a High Deductible Health Plan along with the current self-insured plan.

Medical costs are an area that requires constant vigilance for cost-control. Medical cost-control steps (no longer contributing to premiums for the retiree medical plan, shifting more expenses to retirees, introducing a telemedicine option, and offering a High Deductible Health Plan option) are all ways to reduce Company medical costs.

Since escalation of medical costs has been a very visible and long-term social problem in the United States, it is likely that the medical area would have been similarly addressed with or without decoupling. Whether or not deriving specifically or in part from decoupling, these steps lower operational expenses.

Effective January 1, 2014, the defined benefit pension plan was closed to all non-union employees hired or re-hired after January 1, 2014. This transfers risk to employees. The

[131] Response to Prior DR 063.
[132] Response to Current DR 35.

Company also now offers a lump sum payout to non-union employees, further reducing risk to the Company.

Utilities typically subscribe to high quality utility organizational surveys that provide industry benchmarks for employee salaries and benefits and then adjust salaries and benefits where possible to approximate these national benchmarks. This is one of the reasons why utility pay, and benefit packages are generally better than those offered in most sectors of the national economy or in local communities.

We note the general trend across business sectors towards the replacement of defined benefit pensions by 401K plans. Although comparatively slow to develop in the utility industry, this is now also a utility industry trend.

The Company is introducing more automation for IS/IT and is working towards providing longer contracts to venders in return for discounts.

From experience, the Information Services/Information Technologies areas have long been somewhat independent of utility organizational cultures. Utilities are very reliant on data and computer systems, yet these systems tend to be operated somewhat by their own internal logics which can sometimes present unexpected yet necessary new costs. Working towards discounts from venders in these areas is a useful approach to cost-control. Whether or not deriving specifically or in part from decoupling, this step lowers operational expenses.

We see no current adverse impact on cost control and operational efficiency.

Energy Conservation and Energy Efficiency

In discussion with Avista energy conservation management staff, we explored the possibility of adverse effects on conservation effort.

- The response from staff is that "…our job is to get customers to use less of our product," and that "decoupling was put into place to offset the loss of revenue" from helping customers reduce their energy use.
- Staff say there is no negative feedback from the executive level when planned energy savings are exceeded.
- Staff feel backing from management and the organization. The goal is to "get maximum savings."

According to staff there was a slowdown during the pandemic, and there was not a quick bounce back. However, there is a new midstream program that will help meet conservation goals. At the same time, the programs are experiencing higher costs and supply chain problems and interest rates are up. There is also a lack of skilled workers for the energy efficiency agencies. There are continuing building structure and health and safety issues that noticeably affect residential programs.

We detected no negativity or “off mission” indications from staff. Staff appear to be working diligently, with a sense of confidence in the full backing from management and executive levels for energy conservation and energy efficiency engagement. From the perspective of staff, decoupling is having no adverse impact on energy conservation and energy efficiency effort.

These responses coincide with general knowledge of the current utility industry. The pandemic did cause slowdowns in goal achievement across virtually all utility energy conservation programs in the US and Canada. That cost per unit of energy conservation achievement goes up while savings per unit of program investment decreases is an artifact of approximately fifty years of operation under the “least cost planning” framework and associated cost controls on programs. For about fifty years, lower-cost projects and programs have been authorized while higher costs have been avoided, saving the high-cost work for last. Now, however, we are in the future and wish that more of the higher cost work had been addressed first, and more of the lower cost work had been deferred for us to include in projects now.[133]

At the recent ACEEE Energy Efficiency as a Resource conference in Philadelphia, the low-income panel had three presentations on the cost of weatherization of homes requiring structural rehab and health and safety work to permit full weatherization.[134] These homes,

[133] Climate change is a different world than least cost planning. In climate work, the important guideline is to do high-cost and more difficult measures first. “The longer we delay meeting total climate investment needs, the higher the costs will be, both to mitigate global temperature rise and to deal with its impacts.” Climate Policy Initiative, Global Landscape of Climate Finance 2023, https://www.climatepolicyinitiative.org/publication/global-landscape-of-climate-finance-2023/. (Search for “The Costs of Inaction.”) The other consideration is that government and institutional ability to fund and accomplish measures will substantively deteriorate due to climate change as we move forward into the future. This means that discounting the future is not part of the planning framework. In fact, a realistic approach is to discount the present in favor of the future so that much of the most difficult work will have been accomplished (be appropriate sunk cost) by specific dates, such as 2050, 2075, 2100, or 2150. This is a different planning framework than we are used to, but appropriate and necessary for the climate era.

[134] Each of the three presentations is focused on the problem of weatherizing low-income homes, and, specifically, the approximately one-third of low-income homes that require substantial rehab prior to installing the weatherization measures. These are homes that would normally be treated as "walkaways" and not counted as completed, or homes that are given minimal measures and counted as completions. The framework running on 'least-cost, first" for fifty years automatically accumulates an extensive list of higher cost projects put off to the future. We are now in the future and wish that these had been addressed over the last fifty years. Costs include bringing homes to current weatherization standards, but do not include new climate adaption measures. Minor-Baetens works for Guidehouse. Popkin is weatherization manager for the Philadelphia Gas Works, and Goodgal is policy manager for an association of weatherization companies in Pennsylvania. Minor-Baetens does studies, Popkin makes things work on the ground, and Goodgal works on getting the money. Generally, these initial projects require special funding, and pooling funds from different sources. The federal government ran a pilot for some of these homes, with full funding, and some states have followed up with state funding. The thing is, when advocates say "just weatherize low-income homes and electrify" the intent is good, but the tacit knowledge is missing. We can do it, but the cost is a high multiple per dwelling unit of what passes a DSM era cost effectiveness test. So, if we want to do it all we have to change from a least-cost, first approach and actually do it all. Minor-Baetens, Jessica, “Home Repair as a Prerequisite to Energy Efficiency Equity in

normally "walkaways," are being addressed under the goal of social inclusion and consist of about 30% of low-income homes in Michigan and Pennsylvania. It takes approximately $30,000 to $50,000 to successfully treat each of these homes. The estimate to treat Michigan homes, developed by Guidehouse, is between $3 and $4 billion dollars. This is the cost of full standard weatherization; it does not include costs of making homes climate hardened. Washington has a similar "walkaway" and cost problem.

At the same time, shortage of experienced energy conservation/energy efficiency staff is occurring throughout the US and Canada, and as we go forward, supply chain problems continue to occur, although not as frequently as during the pandemic.

These are current problems throughout energy conservation/energy efficiency programs in the US and Canada. There is no indication that the current problems are related to the presence or absence of decoupling. They are not related to decoupling.

Finding: We see no adverse effect of decoupling on conservation staff and conservation effort. There are problems of increasing cost, shortages of experienced workers, and supply chain problems, but these are currently occurring throughout the US and Canada and are not associated with the presence or absence of decoupling.

Figure 8-8. Finding: Staff and Organizational Support.

Summary – No Adverse Effects

We find no conclusive evidence of any current adverse impact of decoupling on cost control, operational efficiency, price signals, or service quality.

Michigan;" Popkin, Zachaery, Joshua Smith & Alon Abrahamson, "Health and Safety Solutions for Low-Income Philadelphians; Goodgal, Rachel, "Whole-Home Repairs – Pathway to Energy Equity in Pennsylvania." Presentations to the ACEEE Energy Efficiency as a Resource Conference, Philadelphia, Pennsylvania, October 2023.

Section 9. Findings

(1) We find the deferrals and rates for Decoupling to have been calculated by the Company in accordance with the Commission guidance as operationalized by the methodological specification in Schedule 75 and Schedule 175. (Page 1-99)

(2) An important characteristic of the Avista decoupling mechanism is the ability of the mechanism to clear deferral balances even with a rate cap and even in the face of unusual circumstances, such as persistently warmer than normal winters over consecutive years. Because the 3% test is applied using current rates, including the current decoupling rate, the new decoupling rate will adjust higher and be capable of amortizing higher levels of requested recovery. At some point, even if weather or other conditions that caused initially higher deferral carryovers persist, the decoupling rate will eventually adjust to a level that recovers 100 percent of requested recovery and carryover deferral balance will fall to zero. (Page 2-3)

(3) Avista's decoupling mechanism has had a stabilizing effect on revenue, reducing variability in half for electric and by one-fifth for natural gas of variability without decoupling (Page 2-22)

(4) For electric non-decoupled classes, Avista recovers 16% of fixed charges for Extra Large General Service and 100% of fixed charges for Street and Area Lighting through the customer charge. For natural gas non-decoupled classes, Avista recovers no revenue for Interruptible Service and 7% of fixed charges for Transportation Services through the customer charge. (Page 3-3)

(5) We find no reason to suggest a relationship between decoupling and conservation results for program savings, expenditures, or customers served. These relationships are as likely to have occurred in the absence of decoupling as they occurred with decoupling. (Page 4-13)

(6) We find no relationship to be evident between low-income customers and the rest of the residential class related to decoupling. There are changes, but we find no reason to suggest these changes have a relationship to decoupling. The changes are likely driven by other factors. (Page 4-13)

(7) For electricity, the overall energy savings trend is *down*, dominated by the downward trend for Total Residential. The trend line for Total Residential Electric Savings shows an overall decline from 2014 to 2022. Spending is also *down* for Total Residential. Total Residential Electric Savings have *declined* substantially over the years examined. (Page 4-14)

(8) Low-Income Residential Electric Savings have *increased* both absolutely, and as a percentage of Total Residential Electric Savings. For Low-Income Electric Savings (kWh) the trend line slopes upward over the range of years examined. Also, the Low-Income Electric Savings as a percentage of Total Residential Electric Savings *increased* from one percent (1%) to seventeen percent (17%) from 2014 to 2022. (Page 4-14)

(9) For natural gas, Residential energy savings trends for both Total Residential and Low Income are sloping *slightly upward*, while the Ratio of Low-Income to Total Residential Savings (%) slopes *slightly downward*. (Page 4-15)

(10) Based on the reports reviewed for this analysis, it is not evident that the mechanisms have had a positive or negative impact on natural gas conservation savings. Generally, it is likely that exogenous factors have provided substantial impact on natural gas conservation savings. However, since the slopes for both Total Residential and Residential Low-Income Natural Gas savings are positive, these results are consistent with the mechanisms having a positive effect on natural gas conservations savings. While the slope of the trend line for Non-Residential savings for natural gas is downwards, it is only slightly downwards. (Page 4-15)

(11) Based on the reports reviewed for this analysis, it is not evident that the decoupling mechanisms have had a positive or negative impact on electric conservation savings. Total Electrical savings are down, dominated by Total Residential. Non-Residential savings are up, but only slightly. While Total Residential is down, Residential Low-Income is up. (Page 4-16)

(12) The Annual Conservation Reports do not break down savings to exclude the 5% decoupling commitment.[135] The additional 5% decoupling savings data is addressed in setting targets in the Annual Conservation Plan but is not reported in the Annual Conservation Reports which provide the source data for the analysis here. Since the results of the 5% decoupling commitment are not specifically broken out in the Annual Conservation Reports, the Annual Conservation Plan, or the Biennial Program Evaluations, the 5% results cannot be addressed here. (Page 4-16)

(13) New customers are meaningfully different from existing customers in both use per customer and decoupled (distribution) revenue generated per customer. Although the effect is stronger for electric service, and not as pronounced for

[135] In the General Rate Case Settlement Agreement (Docket Nos UE-140188 and UG-140189), the Company agreed, in consideration for receiving a full electric decoupling mechanism, to increase its electric energy conservation achievement by 5% over the conservation target approved by the Commission.

natural gas service, new Residential customers use substantially less energy per customer and generate less revenue per customer than existing customers. Because the number of new customers is small relative to existing customers, the overall impact on deferred revenue is limited, but still meaningful. (Page 5-1)

(14) For electric service, had new customers been included, electric Residential customers would have received a smaller refund; electric Non-Residential customers would have received a higher charge through application of the decoupling tariff (RS 75). (Page 5-5)

(15) For natural gas service, had new customers been included over the 2020-2022 period, Residential customers would have experienced a higher charge, but Non-Residential customers would have received a lower charge through the decoupling tariff (RS 175). (Page 5-5)

(16) Comparison of computed "normal weather" Heating Degree Days (HDDs) and Cooling Degree Days (CDDs) using the standard 30-year rolling average and compared with actuals shows two substantive changes: HDDs are decreasing. As the planet retains more and more heat, instead of reflecting it back into space, the planet, considered as a system, has become unstable in this regard. The associated HDD graph, with a downward-sloping regression line, shows the decreasing HDDs. CDDs are increasing. This means more and more cooling is needed to counter the increasing heat. The associated graph, with an upward-sloping regression line, shows the increasing CDDs). (Page 6-15)

(17) In a review of 30-year, 20-year, 15-year, and 10-year calculations resulting in alternative operational definitions of "normal weather", the 15-year period seems to be the shortest period that still produces relatively accurate results with acceptable precision the observed data and calculations. The 20-year period is the longest period (Page 6-12). Outside these limits there is a serious loss of accuracy or precision.

(18) While the weather adjustment mechanism associated with decoupling continues to the planned effects for removing barriers to energy conservation/energy efficiency and improving revenue stability (for those fixed costs included in decoupling), the major driver of change in energy use is now climate change operationalized as the declining trend of HDDs. Decoupling is, going forward, best understood as a climate change practice, incorporating more timely revenue recovery. (Pages 6-14 to 6-15)

(19) The use of a decoupling rate cap on customer surcharges has the advantage of smoothing out rates and the disadvantage of prolonging revenue recovery. Raising the rate cap to 5% will sometimes increase bills for the next rate year, while lowering bills for the year after that. Going to no-Cap provides quickest recovery. (Page 7-6)

(20) For the annual Customer Service Measures, we find no directionally consistent set of either small or large changes in this analysis. There are no meaningful patterns of negative effects on any of the Section 7 KPIs from 2015 through 2022. (Section 8)

(21) Avista's success rate for Customer Service Guarantees from 2016-2022 averages 99.5%. (Page 8-14)

(22) We find no conclusive evidence of any current adverse impact of decoupling on cost control, operational efficiency, price signals, or service quality. (Page 8-21)

Section 10. Recommendations

(1) **Continuation.** The decoupling mechanisms have worked as expected to stabilize revenue without impacting utility operations and energy efficiency programs. We also found no evidence of adverse impacts to any customer groups. Since the program continues to work as planned in this second evaluation, we recommend the electric and natural gas mechanisms be continued.

(2) **Direct Consultant for Biennial Program Evaluations to address 5% adder.** In developing this decoupling study, we were not able to specifically address the 5% adder for energy savings since there was not a specific breakout of this in the Biennial Program Evaluations. We recommend that the evaluator for the Biennial Program Evaluations be assigned to specifically address the 5% adder for energy savings in future evaluations, so that this information will be readily available.

(3) **Direct Biennial Program Evaluations to break out spend by service**. In developing this decoupling study, we note a need for the Biennial Program Evaluations to add a table showing planned and resulting energy savings and conservation spend separately for electric and natural gas conservation annually, beginning with 2014. Inclusion of a subtask for the evaluator for the Biennial Program Evaluations to report spend separately for electric and natural gas conservation annually, beginning with 2014 would add useful trend information to the evaluations.

(4) **Direct specific treatment of 5% adder in Conservation planning and achievement reports.** For Conservation planning and Conservation achievement reports, it would be useful for future reports to require specifically addressing the 5% adder for energy savings.

(5) **Direct reporting of separate spend for Conservation planning and Conservation achievement reports**. It would be useful for future reports to require the addition of a table showing planned and resulting energy savings and conservation spend separately for electric and natural gas conservation annually, beginning with 2014. This would add useful trend information to the evaluations.

(1) **Operational definition of normal weather:** In a review of Avista's calculations using a 30-year, 20-year, 15-year, and 10-year rolling average as alternative operational definitions of normal weather, we recommend the 20-year period as the longest time window and the15-year period as the shortest time window for consideration. We also note that climate scientists are tending to consider a 20-year calculation for the separate, but similar, problem of estimating the year that 1.5 degrees Celsius change has been reached (rather than 30-years – see Appendix). In addition, NOAA has selected 15-years as the time window for an

additional TMY series to accommodate climate change (to run alongside the traditional 30-year TMY data). The NOAA choice to add a 15-years calculation is not actually a choice for 15-years but a decision to provide both 30-year data and 15-year data, which together bound a center of 22.5 years (though weighting could be used to produce other results). The primary advantage of a 20-year period is that it is less weighted towards weather that is not likely to recur (less than would be the case for a longer period), while avoiding the greater instability of shorter time windows. The primary advantage of a 15-year time window is that it provides more stability in estimation than any period shorter than this. We are in a time in which the concept of “normal weather” is becoming less and less meaningful – it was meaningful in a stable framework that did not include a strong and strengthening climate trend, but that is not reality. Yet the decoupling framework makes an estimation of normal weather necessary. Moving to 20-years is a moderate step towards incorporating what is essentially a dynamic situation. It might be tried for some years as a reasonable step, and then, based on practical experience, if the question of normal weather continues to have relevance, the increasing build-up of planetary heat energy may suggest a move to 15-years. And then, further on, we can anticipate finding ourselves unsure of why we once thought the question of normal weather was meaningful and we will be asking a different question within a climate change framework. While frameworks shift for understanding and describing what are doing, decoupling and associated calculations continue to provide increased revenue stability.

Section 11. Appendix

This appendix contains three topics. First, a table of rate cases and test years. Second, a citation to the use of 20-year analysis by the Intergovernmental Panel on Climate Change (IPCC). Third, a short but deeper further discussion of the problem of "normal weather."

Rate Cases and Test Years

Rate cases and test years are shown in Table 11-1. When two test years are relevant for a single calculation, Avista derives the results as a weighted average of the two test years, according to the number of months from each.

Rate cases may include more than one test year. In such cases, the operative test year may be formed from months in different test years. Avista's computer results are typically computed using a single test year. The natural gas and electric cases use the same test years, so while there are eight rate cases there are four test years.

When two test years are relevant for a single calculation, Avista derives the result as a weighted average of the two test years, according to the number of months from each test year.

Table 11-1: Electric and Natural Gas Cases and Test Years.

Decoupled Revenue Per Customer History			Normalized KWh Usage		Base Year Customers		Base Year kWh Use Per Customer		Decoupled Revenue Per Customer	
Electric Rate Case	Effective	Test Year Ending	Res	Non-Res	Res	Non-Res	Res	Non-Res	Res	Non-Res
UE-170485	5/1/2018	12/31/2016	2,361,885,989	2,166,198,394	209,864	35,622	11,254	60,811	$ 699.75	$ 4,352.96
UE-190334	4/1/2020	12/31/2018	2,374,703,689	2,131,033,094	215,665	36,586	11,011	58,247	$ 752.84	$ 4,413.88
UE-200900	10/1/2021	12/31/2019	2,395,485,525	2,131,091,333	218,293	37,020	10,974	57,567	$ 857.24	$ 4,795.30
UE-220053	12/21/2022	9/30/2021	2,499,403,391	2,098,439,025	223,463	37,969	11,185	55,267	$ 996.06	$ 4,938.95

Decoupled Revenue Per Customer History Natural Gas			Normalized Therm Usage		Base Year Customers		Base Year Therm Use Per Customer		Decoupled Revenue Per Customer	
Rate Case	Effective	Test Year Ending	Res	Non-Res	Res	Non-Res	Res	Non-Res	Res	Non-Res
UG-170486	5/1/2018	12/31/2016	119,446,617	52,067,051	153,955	2,771	776	18,788	$ 314.43	$ 4,621.52
UG-190335	4/1/2020	12/31/2018	128,985,980	55,884,877	161,791	3,073	797	18,186	$ 363.89	$ 4,870.36
UG-200901	10/1/2021	12/31/2019	132,095,604	60,325,922	165,362	3,105	799	19,432	$ 410.99	$ 5,182.28
UG-220054	12/21/2022	9/30/2021	137,376,752	58,747,734	170,025	3,181	808	18,470	$ 447.99	$ 5,166.98

Notes:
Test year definitions from Workbook "B" of each annual filing. See Worksheet titled "Pg ? UE-000000 Auth-2" where UE-0000000 refers to docket number of rate case.

IPCC Precedent for 20-Years

A separate, but related, problem from the decoupling weather estimation problem is determining the year in which the planet passes the 1.5-degree Celsius mark (and other global warning levels).[136] Since weather has variability (seasonals, cyclicals, cyclical-irregular, and irregulars) as well as trend, the specific problem is to know the year in which the 1.5-degree Celsius mark is exceeded, without waiting for a full 20 years for confirmation. For this problem, the base case has been defined as the average weather from 1850-1900. The year that we exceed 1.5-degree Celsius global warming level is defined as the midpoint of the 20-year period at or beyond the 1.5-degree level (Figure 11-1).

"By this definition, 1.5 degrees Celsius of warming would be confirmed once the observed temperature rise has reached that level, on average, over a 20-year period."

"Any definition must be consistent with how 1.5 degrees Celsius is already defined by the IPCC; that is, using 20-year averages attached to a midpoint."

"The IPCC already uses long-term averages over recent decades for such baselines; it does not use the end point of 30-year trends or statistical smoothing."

Betts, et al, *Nature*, Vol 624, 7 December 2023, P. 34.

Figure 11-1: Exceeding 1.5 Degree Celsius Global Warming Level.

The suggested solution is to use the immediately available last 10 years plus a projection of ten future years (Figure 11-2).

"We propose…the 20-year average temperature rise centered around the current year. This is estimated by blending the observations for the past 10 years with the climate model projections or forecasts for the next 10 years, and taking an average over the 20-year period."

Betts, et al, *Nature*, Vol 624, 7 December 2023, Pp. 34-35.

Figure 11-2: An Average of 20-Years.

The part of this solution that is most relevant to the decoupling weather estimation problem is the use of a 20-year period both as a standard of the Intergovernmental Panel on Climate Change (IPCC) and in the specific design of the solution suggested.

[136] Betts, Richard A., Stephen E. Belcher, Leon Hermanson, Albert Klein Tank, Jason A. Lowe, Chris D. Jones, Colin P. Morice, Nick A. Rayner, Adam A. Scaife & Peter A. Stott, "Approaching 1.5 Degrees Celsius: How will we know we've reached this crucial warming mark? *Nature*, Vol. 624, 7 December 2023, Pp. 33-35.

The “Normal Weather” and “Weather Normals” Problem

Weather adjustment associated with decoupling now primarily reflects the strength of climate change, rather than other factors, such as energy conservation and energy efficiency improvements. Decoupling weather adjustment may now be seen as an essential climate practice, to keep utilities solvent during climate change, though calculations will need to be changed away from the concept of “normal weather.” As discussed in Section 6, the concept of “normal weather” (and, with it, the use of calculated “weather normals”) is losing meaning. Since the climate trends towards fewer heating degree days and more cooling degree days are now strong and becoming stronger, calculation of weather normals is questionable. Not that the calculations, using 30-years of data cannot be performed as easily as in the past, but the results are abnormal weather (weather as it would have been if there were no climate change), rather than normal weather (the hotter weather than is now becoming a normal expectation). The method put forward by Betts, et al, above for solution of a different problem – determination of the year at which we fail to protect against a 1.5-degree Celsius global warming level,[137] points towards a different concept for calculation of weather, a concept which involves taking the trend toward ever increasing planetary heat energy retention (trend towards increasing HDD and trend towards decreasing CDD) into explicit account in the estimation process. Drury and Gattie-Garza propose a different but similar approach to the separate problem of improving estimates of energy savings of conservation measures by taking climate trends into account – using regression estimation to project incremental changes (plus and minus) to energy savings (of a measure or a measure package) by year due to effects of the ever increasing planetary retention of heat energy on measure performance (Figure 11-3).[138]

[137] The focus of Betts, et al is on the problem of determining the year in which the 1.5 degree Celsius of global warming since pre-industrial time is reached (or, more generally, when each climate degree target is reached, for example, 2.0 degrees, 3.0 degrees, or 4.0 degrees Celsius). They propose using a standard 20-year calculation approach but using 10-years of actual data with 10-years of projected data.

[138] The focus of Drury and Gattie-Garza is on the problem of improving energy savings estimates from energy conservation measures and measure packages, in order to adjust expected performance for the increased heat energy in the environment – they show cooling measures show increasing energy savings over time while heating measures tend to show less decreasing energy savings over time as heat energy in the environment increases.

"While future projections or modeling introduce additional uncertainty to energy savings estimates, they represent a method we can use to try and estimate future energy savings and are likely more accurate than using weather data based on previous averages."

"Moving forward, we need to use as close to real-time data as possible to ensure we are accounting for a changing climate as it continues to unfold before us."

Drury, Matt, PE, Opinion Dynamics & Mallorie Gattie-Garza, Opinion Dynamics, "Climate Change and its Effect on Weather Data", American Council for an Energy Efficient Economy, 2016 ACEEE Summer Study on Energy Efficiency in Buildings, *Proceedings*, Pp. 9-1 to 9-11. See P. 9-7 & 9-10

Figure 11-3: Estimates of Future Likely More Accurate.

Dealing with operational definition and computation methods as planetary physical reality changes requires a shift of analytic frameworks. In this shift, comprehension and communication become challenging. Kuhn, in *The Structure of Scientific Revolutions*, which was written as an analysis of science in general, but is primarily focused on physics, talks about this kind of shift of conceptual and analytic frameworks as more like conversion than rational theory choice.[139] Conversion can be understood as analogous to religious conversion. In the transition, communication among cooperating specialists with different knowledge and experience (and with adherence or mixed-adherence to different frameworks) can become difficult, but a kind of "trading language" can develop, permitting progress.[140] This seems to be what is happening with the problem of projecting "normal weather", as the standard calculation now produces "abnormal weather" – weather as it would have been if the planet had not become unstable by the ever-increasing retention of heat energy.[141] Normal weather is now something else. As Kuhn points out, shifting to a new framework can mean the loss of existing questions as well as an emerging focus on new questions and new kinds of results.

[139] Hacking, Ian, Introductory Essay in Kuhn, Thomas S., The Structure of Scientific Revolutions, 50th Anniversary Edition (Fourth Edition). Chicago & London: The University of Chicago Press, 2012, P. xxxi.
[140] Hacking, Ian, op cit., P. xxxii.
[141] Here, Westrum's work on "hidden in plain sight" is relevant. For Kuhn, conversion leads to vision from the new framework ("I was blind, but now I see"). But prior to conversion, to quote Westrum, "An event may be described as hidden; if its occurrence is so implausible that those who observe it hesitate to report it because they do not expect to be believed. The implausibility may cause the observer to doubt his own perceptions, leading to the event's denial or misidentification." (P. 382) "It Can't Be, Therefore it Isn't" (P. 383). Between frameworks (during transition) perception and discussion are awkward. That is where we are now. Clarity, involving both a completion in frameworks and a shift in questions addressed, is coming as climate effects become stronger. Westrum, Ron, "Social Intelligence about Human Events," *Knowledge: Creation, Diffusion, Utilization*, Vol. 3, March 1982, Pp. 381-400.

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AVISTA DECOUPLING EVALUATION

(2020 – 2022)