Exh. KMH-1T

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET UE-25____

DIRECT TESTIMONY OF

KEVIN M. HOLLAND

REPRESENTING AVISTA CORPORATION

I. INTRODUCTION

Q. Please state your name, business address, and present position with Avista Corporation.

A. My name is Kevin M. Holland. My business address is 1411 E. Mission Avenue, Spokane, Washington, and I am employed by the Company as the Director of Energy Supply.

Q. Would you please describe your educational background and professional experience?

A. Yes. I am a graduate of Gonzaga University with a Bachelor's Degree in Business (1992) and Gonzaga University Master's Degree in Business Administration in 1996. I have over 25 years of experience in the energy industry with roles in financial analysis, real time electric system operations, wholesale trading and long-term markets. The majority of my career has been at Avista Corporation, previously holding positions in Resource Marketing, Wholesale Contracts and Credit, Real Time trading, and Energy Efficiency for Avista. I left Avista for a brief period in 2007, rejoining in 2012. Prior to re-joining Avista Corporation in 2012, I was a Structured Transaction Originator for Shell Energy North America leading multiple team efforts to secure long term relationship-based contracts with energy industry companies. In 2022, I was promoted to the Director of Energy Supply at Avista Corporation where I am responsible for Avista's natural gas and electric business operation including trading and marketing, resource planning and acquisition, strategic initiatives, contract negotiation, renewable and emissions compliance, and regional initiatives participation.

Q. What is the scope of your testimony in this proceeding?

A. My testimony offers an overview of the history of the ERM and provides a summary of the factors contributing to the power cost deferrals during the 2024 calendar year review period. I provide an overview of the documentation the Company has provided in workpapers, which the Company agreed to provide in the ERM Settlement Stipulation approved and adopted in Docket UE-030751. A table of contents for my testimony is as follows:

Q. Are you sponsoring any exhibits to be introduced in this proceeding?

A. Yes, I am sponsoring Exh. KMH-2, which contains five pages from the Company's December 2024 Annual Power Cost Deferral Report previously filed with the Commission in Docket UE-011595. These five pages show the deferral calculations for the period of January 2024 through December 2024. Page 1 of Exh. KMH-2 shows the calculation of the deferral, pages 2 through 4 show the actual expenses and revenues, and page 5 shows the retail revenue adjustment. Detailed workpapers supporting the tables and other calculations in my testimony have been provided in electronic format to the Commission, and other parties, coincident with this filing. Workpapers also provide detailed analysis of the various components which resulted in the actual vs. authorized variances.

Q. What was the ERM deferral amount in 2024?

A. For the 2024 calendar year, <u>actual</u> net power costs were more than <u>authorized</u> for the Washington jurisdiction by $22,932,503 (excluding interest). The deferral in the customer surcharge direction for 2024, amounted to $14,639,253. Pursuant to the mechanics of the ERM, the Company absorbed $8,293,250 of increased power costs in 2024.

Q. Are other witnesses sponsoring testimony on behalf of Avista?

A. Yes. Company witness Mr. Ehrbar provides testimony concerning the monthly deferral entries, the deferral balance, and describes the overall proposed net increase to customers.

II. OVERVIEW AND HISTORY OF THE ERM

Q. Would you please explain the history of the ERM and the annual filing requirement?

A. Yes. The ERM mechanism was originally established in response to extremely volatile power supply conditions in the 2000-2001 time period. The purpose of the ERM is to provide a method by which risks associated with differences in embedded power supply costs as compared to actual power supply costs are shared between the customer and the Company. The ERM Mechanism was originally approved by the Commission's Fifth Supplemental Order in Docket UE-011595, dated June 18, 2002, and was implemented on July 1, 2002.

Pursuant to the UE-011595 Stipulation, the Company is required to make an annual filing on or before April 1 of each year. This filing provides an opportunity for Commission Staff and other interested parties to review the prudence of the ERM deferral entries for the prior calendar year. Interested parties are provided with a 90-day review period, ending June 30 of each year, to review the deferral information. The 90-day review period may be extended by the agreement of the parties participating in the review, or by Commission order.

Avista's first Annual ERM Filing covered the six-month period of July 1, 2002, through

December 31, 2002. Avista has made ERM annual review filings for each subsequent calendar year period. Last year's annual ERM filing covering the 2023 calendar year was filed March 29, 2024, in Docket UE-240276.

III. OVERVIEW OF POWER SUPPLY OPERATIONS

Q. How does Avista, generally, manage its power supply resources?

A. Avista Utilities conducts electric planning, procurement, sales, and power resource management activities to assure an adequate supply of electricity to serve customers and other load obligations, as well as to optimize its generation and transmission resources. Numerous variables affect short-term power supply positions and prices. As such, the Company employs an Energy Resources Risk Policy ("Risk Policy") to recognize and actively manage the interaction and dynamics amongst these variables by establishing processes for predicting future load and obligation requirements, resource availability, and management of the expected net surplus or deficit short-term and immediate-term positions.

Many factors cause the resource mix used to meet load obligations to differ from estimates. Actual load obligations are influenced by many factors and therefore rarely match forward estimates. Each of Avista's generating resources has inherent variability due to streamflow and water storage conditions (for hydroelectric plants), mechanical limitations, transmission constraints, fuel availability and delivery constraints, ambient conditions, environmental and permit allowances, and other factors. Avista's Energy Resources department is responsible for fuel management, optimizing the use of electric resources including wholesale power contracts, and dispatching power resources to meet load obligations while providing good stewardship of electric resources.

The Energy Resource department planning involves significant modeling, assumptions, and estimates to predict future situations. Balancing generation to match load obligations requires constant attention, and its variability dictates that flexibility is always maintained. It is necessary to buy and sell energy (or financially equivalent derivative transactions) in hourly, daily, balance of the month, monthly, and longer increments, as well as adjust dispatch plans to meet prevailing conditions. As such, Avista utilizes all power and fuel transactions authorized in its Risk Policy to provide reliable and affordable service to Avista's electric loads and contract obligations and seeks to optimize additional opportunities associated with Avista's energy resources.

Q. What types of transactions will Avista enter into, as detailed and authorized in the Company's Risk Policy?

A. The following are examples of the types of transactions permitted in the context of managing Avista's energy resources and serving the Company's obligations in the short-term and intermediate-term horizons:

- Scheduling and dispatching energy resource facilities owned or controlled by Avista.
- Transactions with other parties for physical delivery of capacity or energy, including fixed price and indexed or formula-priced transactions.
- Ancillary services, such as reserves, load-following, generation imbalance, and others.
- Transportation, transmission, storage and capacity obligations, and rights.
- Bilateral forward transactions with approved counterparties.
- Future contracts traded on an established commodities exchange.
- Swap agreements as a tool for fixed price financial hedges.
- Transactions that allow Avista to buy or sell electricity or natural gas at Avista's discretion.
- Exchange agreements (forward commodity agreements expected to be settled with return of the commodity rather than cash, either with or without associated settlement prices).
- Fuel (supply, delivery, storage, excess fuel disposition) related to specific electric generating facilities in which Avista has ownership or contractual interest including

natural gas, coal, biomass (wood waste), and related emission allowances.
- Streamflow and water storage rights and benefits related to Avista-owned or contracted hydroelectric generation stations including coordination of the related river systems.

Q. How does Avista optimize its energy resources for the benefit of its customers?

A. Avista optimizes its energy resources in several ways. Electric resource optimization involves choices amongst several variables. The Company assesses these variables, detailed below, to select and execute an appropriate mix for short-term and intermediate-term objectives. Intra-month activity during the current month to serve loads, optimize resources, and participate in the electric market is reported after-the-fact in the daily position report if it is relevant to term positions. Electric optimization variables include:

- Scheduling and dispatching of available Avista generating units as indicated by relevant plant parameters.
- Buying fuel to operate a generating facility or selling fuel already available to decrease or eliminate generation from a unit (includes storage).
- Storing or using water for hydroelectric generation that maximizes expected generation value and arranging for water from or for other hydroelectric plants in the coordinated river system.
- Buying, selling, or exchanging electricity in the wholesale market from/to other utilities, power marketers, or independent power producers, including displacing purchases and sales available to the Avista balancing area.
- Buying or selling financial contracts that hedge electric purchase or sale prices and open positions.
- Obtaining transmission rights may be needed to deliver or receive output to or from any Avista generation source or any market and selling surplus transmission rights.
- Optimizing system and off-system resources for the inclusion of emission free resources.
- Buying and selling natural gas basis spread based on natural gas transport contract rights.
- Participating in organized markets such as the Western Energy Imbalance Market, to optimize our system around regional diversity.

Q. Does the Company have an active hedging program?

A. Yes. The Company employs an Electric Hedging Plan to guide power supply position management in the short-term period. The Risk Policy Electric Hedging Plan is essentially a price diversification approach employing a layering strategy for forward purchases and sales of either natural gas fuel for generation or electric power to approach a generally balanced financial position against the expected load as forward periods draw nearer considering time to delivery and market conditions.

The goal of Avista's Electric Hedging plan is to provide reliable electric and natural gas services at a competitive cost for customers while addressing risks inherent to supplying energy and managing energy resources. Energy Resources is responsible for hedging expected electric surpluses and deficits with the goal of optimizing its position and impacting cost variances. To do this, the Company developed its Power Supply Hedging Plan (PSHP) to guide power supply position management in the short-term period. The PSHP is intended to be dynamic, so it remains responsive to Avista's changing resource portfolio, load profile, forward price changes, prevailing market partners and other external factors.

The Company employs a Power Supply Hedge Requirements Report tool (PSHRR). The PSHRR is an analytic tool to guide power supply hedging decisions in the short-term forward period. It provides a process to systematically reduce open positions with forward transactions by buying for expected shortages and selling expected surpluses. An "open" position for this purpose is the forecasted monthly financial position that is not covered by fixed price physical or financial transactions, i.e., the surplus or deficit that is subject to price risk. The plan provides guidance but may not be followed rigidly when management judgment or market conditions warrant other actions, no action, or simply a delay in taking action.

The PSHRR will define potential transactions to reduce open positions for each month or quarter over the available time between the current date and future delivery periods. PSHRR transactions are designed to systematically reduce open financial positions for established hedge delivery periods up to “x” months into the future. The PSHRR is designed to recommend forward time periods for hedge transactions based on risk and/or price indicators. Note that natural gas for load hedges is done on a time basis only; risk/price indicators do not affect our gas for load buying frequency and Avista purchases natural gas for load on an incremental, timed basis.

Moreover, the model includes several estimates such as price, estimated load or other obligations, variable energy resource generation, hydroelectric generation based, and long-term contracts. When a change in these values identifies the need for a transaction, the PSHRR shows the forward time periods and the hedge amount in dollars to resolve open financial position. The PSHRR is dynamic based on the best information available on each business day. Whenever a hedge transaction is executed (or the equivalent change in net financial position forecast occurs), PSHRR recalculates the financial open positions.

Q. What are the recommended forward time periods for the hedge transactions?

A. Avista follows the delivery periods outlined in its Risk Policy. For any given month, known as the Hedge Assessment Month, an assessment of potential hedges would look to the sequential future periods and identify specific timelines and design their strategy based on the resulting blocks. For the most immediate 10 to 12 months, each individual month is addressed individually as monthly blocks. After these monthly blocks, a minimum of four calendar quarters (maximum of six quarters) are addressed in quarterly blocks. One calendar year block (starting a minimum of 19 months in the future) provides the end of the hedge assessment range for the Short-Term horizon.

Q. How does the Power Supply Hedge Requirements Report Work?

A. With the forward horizon split into transaction periods as detailed above, the PSHRR is designed to recommend forward time periods for hedge transactions based on risk limits, price indicators and/or time. The model involves several steps that are described below.

The model measures the Open Heat Rate, and the Power for Load positions, sums these volumes, and multiplies these sums by forward power prices to produce each forward time period's respective net power position. When a change in forward prices, estimated load, hydro or other reported/forecasted values occurs to create the need for a transaction, PSHRR shows the forward time periods and the hedge amount in dollars to resolve open financial position.

The model also measures the amount of gas necessary to serve forecasted load. This gas is hedged at a paced rate on a periodic basis only. Gas is purchased on an incremental basis over the time periods explained above to fuel thermal plants and subsequently serve electricity load. These forward net positions are managed volumetrically—separately from open heat rate and power for load positions.

Hedge Candidates calculated by PSHRR will include volumes of commodities that will resolve the short or long financial positions while not moving the commodity position further from zero. Commodities could include MID-C Peak Power, MID-C Off-Peak Power, MALIN Gas, and AECO Gas. The PSHRR is dynamic based on the best information available on each business day. Whenever a hedge transition is executed (or the equivalent change in net financial position forecast occurs), PSHRR recalculates the financial and volumetric open positions.

Q. Does the Company consider inputs outside of the PSHRR in its Power Supply Hedging Plan (PSHP)?

A. Yes. The PSHP is a guide for transactions that reduce the net surplus or deficit position, but the PSHP is not intended to dictate a strict course of action nor to limit decisions or to replace management judgement. In cases where management either voluntarily or involuntarily makes decisions that deviate from the PSHP, the reasons for deviating from the plan will be documented contemporaneously and reported to the Risk Management Committee (RMC).

Q. How does the Company communicate its position within the Energy Resources Team?

A. All changes that affect the Short-Term electric position are reflected each business day in an electric position report. The daily report depicts estimated loads and obligations, estimated resources, and estimated open positions for power for each month within the first 30 to 41 months in the term horizon. The daily position report will also show current position status compared to the PSHP. The daily position reports for calendar 2024 have been included within the Company's confidential workpapers.

IV. OVERVIEW OF DEFERRAL CALCULATIONS

Q. Please provide an overview of the deferral calculation methodology.

A. Energy cost deferrals under the ERM are calculated each month by subtracting authorized base level of net power supply expense ("authorized") from actual net power supply expense to determine a variance in net power supply expense. The methodology compares the actual and base amounts each month in FERC Accounts 555 (Purchased Power), 501 (Thermal Fuel), 547 (Fuel) and 447 (Sales for Resale) to compute the change in power supply expense. These four FERC accounts comprise the Company's major power supply cost/revenue accounts. The ERM also includes costs or revenues in Accounts 565 (transmission expense), 456 (third-party transmission revenue), and broker fees (557).

In addition, actual expense and revenue for natural gas not burned is included as natural gas sale revenue under Account 456 (revenue) and purchase expense under Account 557 (expense). This would include benefits and costs related to capturing the value associated with power supply's natural gas transportation contracts when they are not needed to satisfy electric retail load needs. All expenses are recorded in accordance with Generally Accepted Accounting Principles and FERC's Uniform System of Accounts.

The total change in net expense under the ERM is multiplied by Washington's share of the Production/Transmission Ratio (PT Ratio) approved in association with base net power supply expense. For this period, that ratio results in a 65.54 percent allocation to Washington. Change in Washington retail sales is then multiplied by the Retail Revenue Adjustment Rate and added or subtracted from the change in power supply expense to calculate the total power cost change. The total power cost change is accumulated during the calendar year until the dead band of $4.0 million is reached. If total power cost changes exceed $4.0 million, then 50 percent of power cost increases, or 75 percent of the decreases, between $4.0 million and $10.0 million, and 90 percent of the power cost increases or decreases in excess of $10.0 million are recorded as the power cost deferrals and added to the power cost deferral-balancing account, as illustrated in Table No. 1 below:

Table No. 1 - ERM Sharing Bands

Annual Power Supply Cost Variability	Deferred for Future Surcharge or Rebate to customers	Expense or Benefit to the Company
First $4M at 100%	0%	100%
$4M to $10M at 25% (rebate)	50%	50%
$4M to $10M at 50% (surcharge)	75%	25%
Over $10M at 10%	90%	10%

Q. Please explain how the retail revenue adjustment is determined in the ERM.

A. The ERM includes a retail revenue adjustment to reflect the change in power production and transmission expense recovered through base retail revenues, related to changes in retail load. The retail revenue adjustment rate calculation is based on the average rate of the power supply expense related FERC accounts included in the Company's general rate case. The retail revenue adjustment for January 1 through December 31, 2024, was $12.53/MWh.

The monthly retail revenue adjustment in the ERM is computed by multiplying the retail revenue adjustment rate times the difference between actual and authorized monthly retail megawatt-hour sales. If actual megawatt-hour sales are greater than the base, the retail revenue adjustment will result in a credit to the ERM deferral (reduces power supply costs). If actual megawatt-hour sales are less than base, the retail revenue adjustment will result in a debit to the ERM deferral (increases power supply costs).

V. SUMMARY OF DEFERRED POWER SUPPLY COSTS

Q. How did actual power costs differ from the authorized level of power costs, and how was this variance shared between customers and the Company?

A. During 2024, actual net power costs were higher than authorized power supply costs for the Washington jurisdiction by $22,932,503 (surcharge). Pursuant to the mechanics of the ERM described above, the total difference between actual and authorized power supply expense was $22,932,503. Of this total, the Company absorbed $8,293,250, and a deferral was recorded in the amount of $14,639,253. (excluding interest), as shown in Table No 2 Below:

Table No. 2 – 2024 ERM Results

	Total	Absorbed (Avista)	Deferred (Customer)
First $4M at 100%	$ 4,000,000	$ 4,000,000	$ -
$4M to $10M at 25% (rebate)	$ -	$ -	$ -
$4M to $10M at 50% (surcharge)	$ 6,000,000	$ 3,000,000	$ 3,000,000
Over $10M at 10%	$ 12,932,503	$ 1,293,250	$ 11,639,253
	$ 22,932,503	$ 8,293,250	$ 14,639,253

Q. Please summarize the market conditions in effect during the Review Period that contributed to the variance between the actual power supply expense level and the authorized power supply expense level.

A. The authorized level of power supply expense (authorized) is intended to be a forecast of anticipated expenses based on the expected market conditions, generation asset dispatch and costs associated with energy supply. The level of authorized expense is intended to capture all future assumptions of energy costs on a normalized basis (adjusted for known and measurable changes). However, the base does not account for unknown variables that are affected both by Avista's owned assets, external market conditions, and weather conditions, to name a few. A variance occurs, and a deferral is recorded, when the level of actual expense differs from the authorized level of power supply expense. The older the authorized base, the less likely the authorized base will accurately reflect the actual market conditions that are experienced in the applicable year. This leads to more opportunities for a variance between authorized and actual expenses.

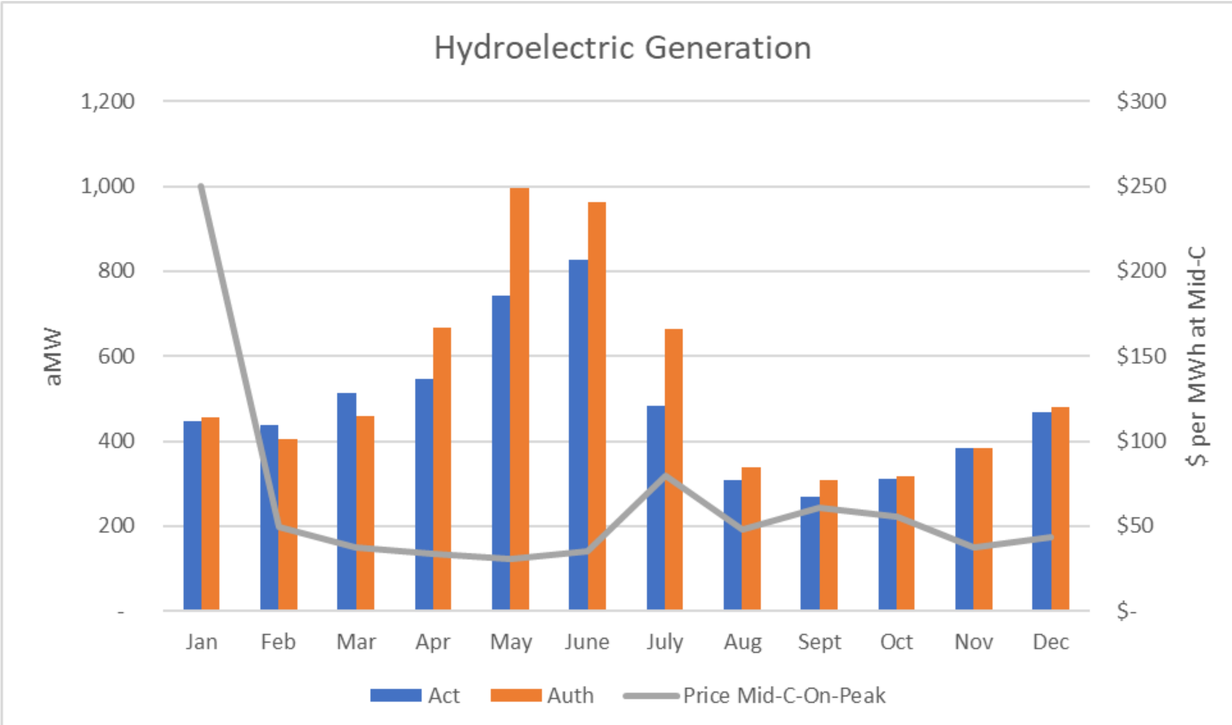
For Avista, 2024 authorized expense levels were based on data available in 2021 and established in Docket UE-220053. By the end of the 2024 calendar year, the test period information was as much as thirty-six months old, and the pro-forma period was as much as 24 months. Market dynamics changed considerably from the time authorized was established to the 2024 review period The most prominent market conditions which deviated from authorized, and therefore impacted the ERM deferral, are attributed to: 1) lower than forecasted precipitation and snowpack which reduced hydroelectric generation from both Avista-owned and contracted-for resources; 2) increased activity in both market purchases and market sales and 3) increased load needs in response to temperature variations. As indicated in Figure No. 1 below, the variance for the month of January contributed by far the most to the overall increase in expense compared to the authorized base and associated surcharge deferral. I will describe the market factors which contributed to this variance in the following section.

<u>Figure No. 1 Actual Expense vs. Authorized Expense</u>

Q. Please describe the conditions that impacted hydroelectric generation supply during 2024.

A. Hydroelectric generation in 2024 fell short of authorized levels due to below-average precipitation and unusually warm temperatures early in the 2023-2024 winter. Snowpack in January 2024 that was only about 50% of the normal level. These conditions persisted into 2024, with precipitation lower than normal the remaining months of Winter and Spring of 2024, except for February. The results of these conditions was a runoff season which led to one of the lowest levels of hydroelectric generation seen in the past 36 years. In fact, 2024 marked one of the fourth lowest levels of runoff in the 77 years data is available. Apart from February and March, each month in 2024 had actual hydroelectric generation less than the authorized level. Compounding the impacts of these poor hydro conditions, was higher-than-normal temperatures in July – September which pushed up load demand and put upward pressure on electric and natural gas costs. On a combined basis, inclusive of the Clark Fork, Spokane and Mid- Columbia River systems, hydroelectric generation for 2024 was <u>significantly</u> lower than average, totaling 478 aMW for the year compared to an authorized estimate of 536 aMW; a net reduction of 58 aMW. Figure No. 2 below for 2024 monthly actual and authorized hydroelectric generation along with Mid-C prices used to value the generation variance. When priced at market, the impact of the lost hydro-electric generation, reflected in the generation variance, is higher than authorized expense of approximately $13.2 million.

<u>Figure No. 2 Total Hydro Generation Summary for 2024</u>

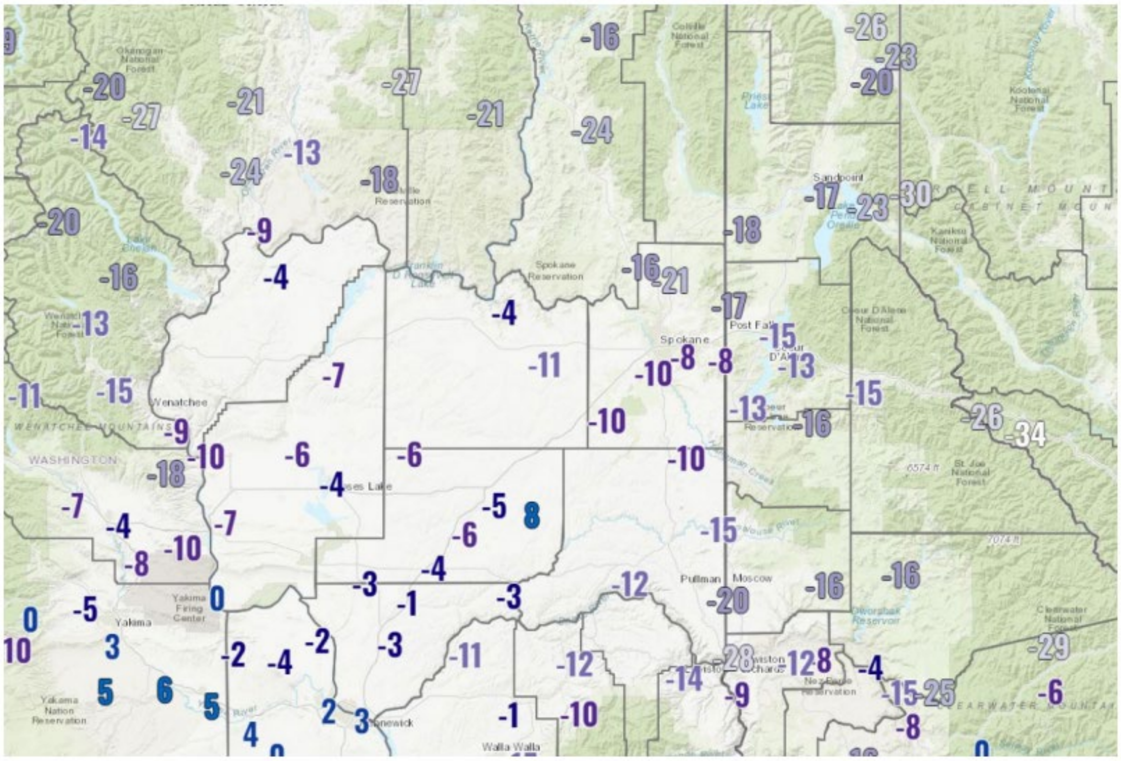


The Company utilized its non-hydro resources, including market purchases and sales, to meet customers' load requirements and optimization when market conditions were economic to do so. These areas are addressed later in my testimony.

Q. How did power prices deviate from authorized in 2024?

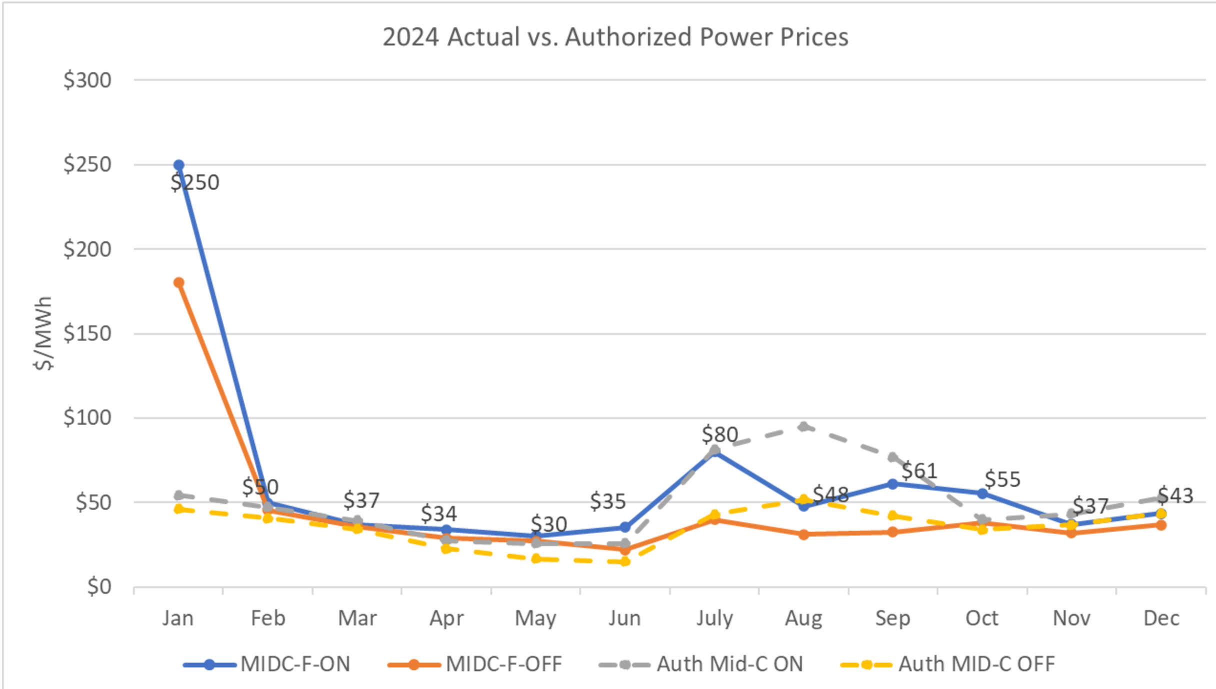
A. In 2024, Mid-C power prices deviated from authorized primarily in the month of January in response to extreme weather events which pushed up demand. In mid-January, the Pacific Northwest experienced a period of extreme cold weather which resulted in temperatures below zero for 10 consecutive days. At its coldest, temperatures were -10 degrees Fahrenheit as compared to an average low of 24 degrees Fahrenheit. Several load-serving entities set new peak demand records over the weekend, including BPA which set a new record for the last two decades for load. Temperatures on January 13, 2024, the coldest day in that period are illustrated below:

<u>Figure No. 3 Coldest Temperatures January 13, 2024</u>



In addition to this cold, constraints on the transmission interties significantly limited the Northwest's ability to import power which put more pressure on energy pricing. The sustained subzero temperatures also impacted wholesale natural gas costs, as well as stream flows, which reduced the availability of hydroelectric generation. With a lack of regional wind, as well as other transmission intertie constraints coming from California, wholesale power prices were under substantial pressures for the entire Northwest. This is reflected in the January average price for Mid-C heavy-load pricing which peaked at $249.95 per MW, making it the highest monthly average price in 2024. Especially when combined with an increase in load due to the cold, the impact of these prices was significant. However, from February through June, prices stayed only slightly above the authorized levels, fluctuating between $3 and $10 for both heavy and light loads. Figure No. 4 illustrates the 2024 Mid-C power prices compared to authorized.

<u>Figure No. 4 – 2024 Mid-C Power Prices</u>

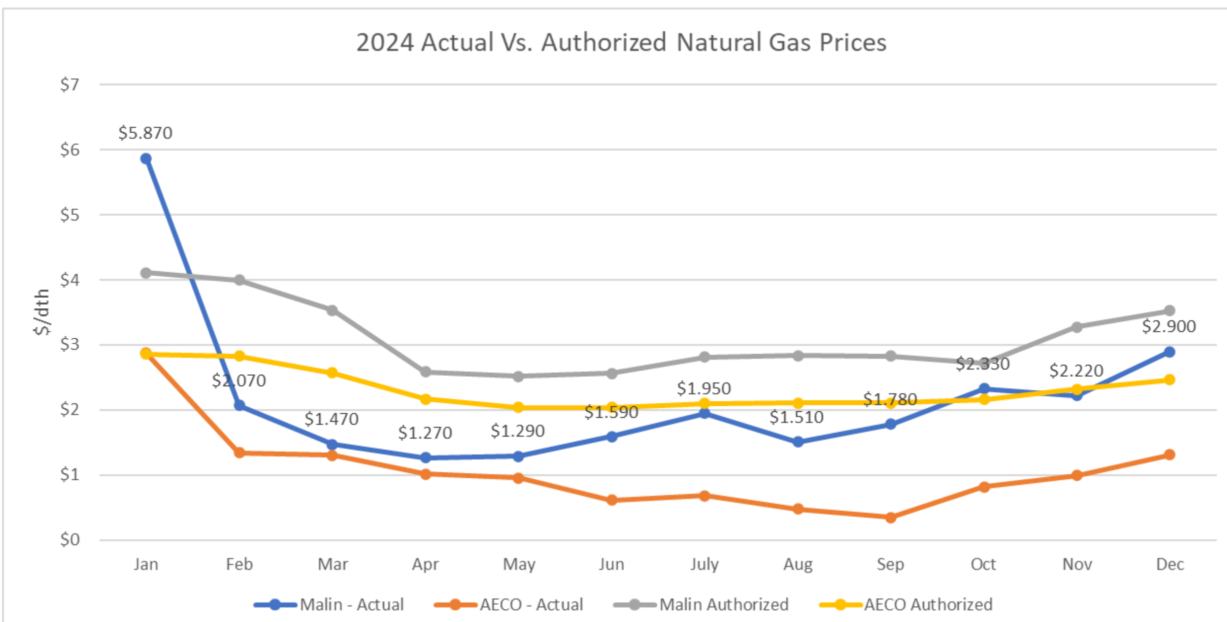


For the second half of the year, actual power prices were *lower* than authorized, particularly in August and September. In August heavy load prices were lower than authorized for both heavy load and light load, $47 and $21, respectively. Also, temperatures were higher than normal in all the summer months, which typically would drive prices much higher than experienced. In July alone, Spokane hit a record for 20 consecutive days of temperatures above 100. In spite of these conditions, prices for the summer months remained below authorized in spite of the associated increased load. Likely this is reflective of the significant amount of energy storage resources that came on line to further optimize variable energy resources in California, pushing up regional supply.

Q. How were natural gas prices different than those assumed in the authorized level of power supply expense?

A. Natural gas was often economic for both serving the load and for resource optimization. With the exception of January 2024, where prices were higher than authorized due to the extreme cold and pressure previously discussed and the reliance on storage during this period. On average, 2024 average monthly natural gas was far more stable than in the prior year, likely reflective of near record level storage balances (after January) and markets in a period of over-supply. This is true particularly at Malin, where an increase in variable energy resources in California reduced the demand for natural gas, resulting in relatively stable prices throughout the year. See Figure No. 5 for monthly gas prices during 2024:

<u>Figure No. 5 Natural Gas Prices for 2024</u>



Q. How do natural gas prices and electric prices correlate with one another?

A. Natural Gas prices and electricity prices are the inputs for determining the value of the natural gas generation fleet. When market heat rates (the ratio of power prices relative to natural gas prices) rise, the *value* of the power that the thermal fleet can generate increases more than the costs incurred to fuel the plants. The result is an increase in natural gas generation to be used for wholesale sales during hours when the fleet is economic. A plant is determined to be economic when the cost to fuel and operate the plant per MWh of generation is below the cost of power in the market. Primarily during the first half of 2024, pricing was such that it remained economically beneficial to generate both for customer load and to sell into energy markets for the benefit of customers. This resulted in higher optimization revenue on the electric side, which ultimately served to reduce customer costs.

Q. How did Avista optimize its energy resources to benefit customers?

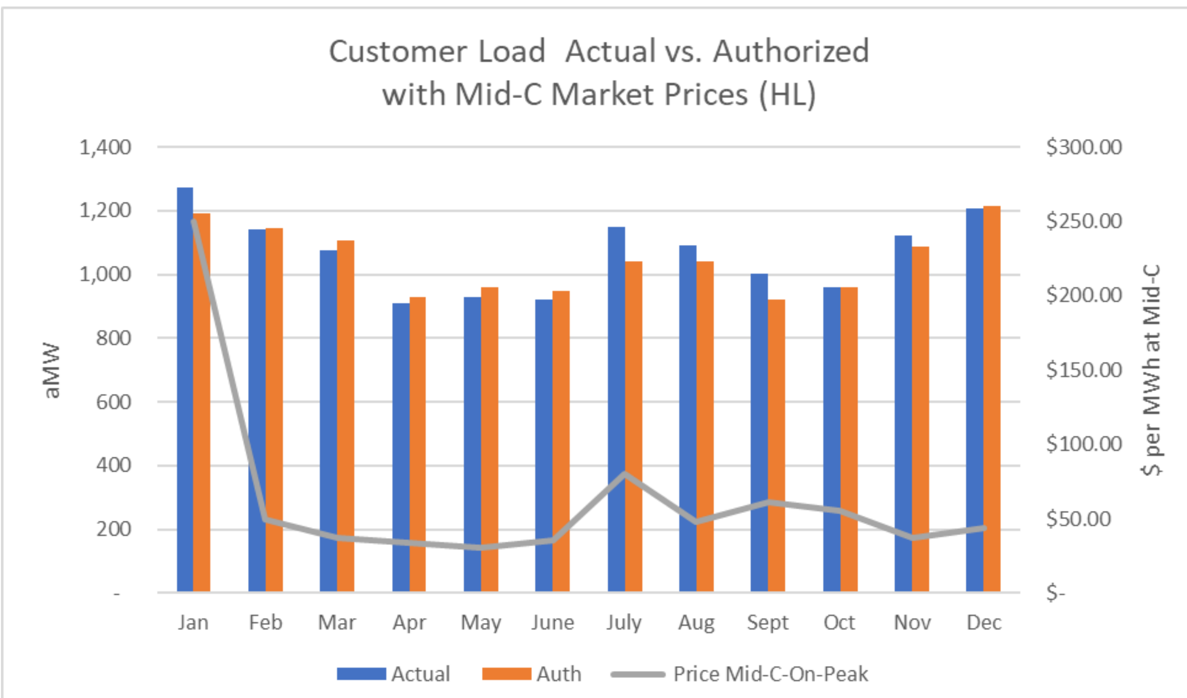
A. These optimization activities are illustrated primarily in the level of net purchase/sales. It is important to note, however, that some of the offsetting expenses for net purchases/sales are reflected in the natural gas fuel variance. However, as these transactions are literally comprised of hundreds of deals, the discussion here will be limited to net purchases/sales. In 2024, Net Sales exceeded authorized by $34.1 million (system basis), more than offsetting the result of unfavorable hydroelectric conditions. As previously mentioned, the value of Avista's natural gas-generating resources was higher than the fuel cost to generate that power. When Avista's total load is served by Avista resources, excess energy can be sold, and the revenue is credited to sales. Conversely, when load exceeds Avista resources, Avista will serve that portion of its load with market resources at the market price available at that time.

In addition to the generation from Company-owned or operated resources, Avista engages in both short-term market transactions (purchases and sales) as well as long-term structured transactions with counterparties. The Company considers several factors including economics, load requirements, and hydro conditions when evaluating the benefits of off-system sales. Finally, Avista's real time and day ahead trading groups review several market indicators to capture the time-spread associated with purchases and sales. When market conditions are deemed appropriate, any day ahead purchases not utilized to meet load requirements may be sold on an hourly basis to reduce overall power supply expenses. These transactions, described above, contributed to the increased value of sales, entirely offsetting any purchases cost.

Q. How did customer loads in 2024 compare to the authorized levels?

A. Customer loads were higher than authorized primarily in January and the Summer months of July – September, as previously described. On an actual vs. authorized basis, the highest months where customer loads deviated from authorized were July and September. Customer loads were higher by 71 aMW in January, followed by July of 109 aMW and September of 82 aMW. In total, for 2024 customer loads were approximately 20 aMW higher than authorized as illustrated in Figure No. 6 below.

<u>Figure No. 6: Customer Loads Actual vs. Authorized</u>



Throughout the year, load needs are met using either Company-owned or contracted-for generating resources such as natural gas or wind and solar, or through market purchases. Several methods are utilized to ensure the optimal combination of resources are utilized to meet this increased load in the most economic manner. However, for comparison purposes, when priced at market, this increase in load resulted in a higher than authorized expense by $26.5 million for 2024, including the impact of the retail revenue credit ($11.7 million retail revenue credit plus $14.6 million load variance). The retail revenue credit is intended to offset the impact of volume fluctuations throughout the year. Meeting these increased load requirements was the third highest contributor to the expense variance when compared to authorized. Particularly in periods where prices were higher than authorized, the impact of these increased loads is substantial. See the variance explanation below for additional information.

Q. Did the Climate Commitment Act impact market price and volatility.

A. Yes. As the CCA was not in effect during the period of time in which authorized was established, it was not possible to anticipate the impact of such a broad reaching environmental policy. The first year of the implementation of the CCA was fraught with uncertainty, including price and impacts on its impact to dispatch of resources, the level of imports and exports at the Mid-C, as well as allowance obligation itself. While it is not possible to definitively isolate the impact of the CCA on prices, there appeared to be upward price pressure as the market attempted to adjust to this uncertainty.

VI. OVERVIEW OF VARIANCE COMPONENTS

Q. Please provide an overview of each component of the variance analysis.

A. Based on timing, economic factors, and available resources, the Company combined resources and market transactions to meet its current demands and capitalize on market prospects, leading to costs higher than those authorized for 2024. The impact of the transactions is reflected in various general ledger accounts and should ideally be viewed collectively. However, due to the numerous transactions for each category, a direct one-to-one analysis fails to capture the nuances associated with providing energy in every hour of the Review Period.[1]

Table No. 3 below provides the primary components of the variance analysis including the "Cost Variance" and "Generation Variance". These two categories of variance make up the total amount of variance within the ERM and are further described below. Please note in all variance tables, a positive number represents unfavorable; a negative number indicates favorable.

Table No. 3 – 2024 Variance Factors (+) Unfavorable (-) Favorable

Washington Share				
		Cost Variance	Generation Variance	Total Variance
1	Hydroelectric Operations	$ 22,989,509	$ 13,406,751	$ 36,396,260
2	Net Purchases/Sales	$ (12,393,503)	$ (21,706,056)	$ (34,099,559)
3	Natural Gas Plant Generation	$ 7,844,356	$ (8,317,735)	$ (473,378)
4	Thermal Generation	$ 4,692,430	$ 2,031,564	$ 6,723,994
4	Wind Generation	$ 1,970,812	$ 16,939	$ 1,987,750
5	Other	$ 6,390,978	$ -	$ 6,390,978
6	Net Transmission Revenue	$ (12,393,503)		$ (12,393,503)
	Subtotal	$ 19,101,080	$ (14,568,537)	$ 4,532,543
7	Retail Revenue Rate Adjustment	$ 11,968,808		$ 11,968,808
8	Load Variance		$ 14,568,537	$ 14,568,537
9	Total Variance	$ 31,069,888	$ 0	$ 31,069,888

For purposes of this variance analysis, workpapers provided by Avista differentiate between the "cost variance" and "generation variance." The cost variance is a more traditional, accounting depiction representing the price/quantity variance[2] comparing actual values to

[1] Please note the Company has provided workpapers supporting all impacts listed in Table No. 1.
[2] The cost variance can be further broken down by price variance (change in price multiplied by actual price) and volume variance (change in volume times authorized price).

authorized values as recorded to the general ledger. The "generation variance"[3] is an economic look which represents the value each resource contributed towards meeting customer load requirements. The generation variance essentially reallocates the variances to the applicable resource to represent the market value the plants provided towards meeting load requirements. The total variance is a function of both generation deviations and the estimated market price of power with the primary purpose of providing an indicator as to how each component of the Company's overall resource stack, adjusted up or down, ultimately met changing load requirements. The variance analysis is intended to illustrate the overall impact of each component of power supply costs, however, it does not fully capture the impact of individual months where a high/low cost of energy is coupled with higher/lower customer load.

Each individual line item from Table No. 3 is further discussed below.

Item No. 1: Hydro Generation Surcharge ($36,396,260 higher than authorized base). As previously mentioned, total hydro generation was lower than the authorized level by 58 aMW resulting in total power supply expense exceeding the anticipated authorized base by $13.4 million compared to authorized on a generation variance basis. Company-owned plants on the Spokane River and Clark Fork River were lower than authorized by 65 aMW and 13 aMW respectively. Offsetting these unfavorable variances, was an increase in generation capacity due to a new contract with Chelan PUD, which resulted in a favorable variance of 21 aMW. This contract was effective in September 2024.

Contributing to a cost variance of approximately $23.0 million (for a total variance of $36.4), the Company contracts with three Public Utility Districts (PUD) for the Mid-Columbia Dams including Grant County PUD, Chelan County PUD, Columbia Basin Hydro, and Douglas PUD.

- In 2024, Grant County's "Meaningful Priority Contract" was higher than authorized by approximately $9.6 million. Each year the price associated with this contract is set based on a market "auction" and the results of that auction are passed back to all "Meaningful Priority Contract" participants. The value of this contract provides Avista with much needed hydro

[3] Workpapers provide the generation variance calculation. For ease of reference the formula is as follows: Gen.Var = (actual HL MWh - authorized HL MWh) * Actual HL price + (actual LL MWh - authorized LL MWh) * Actual LL price.

flexibility and capacity and is a valuable part of its overall portfolio for meeting customer demand, however, the costs associated with the resource contributed to the overall cost variance.

- The additional contract with Chelan PUD increased its share from 92.9 MW in 2023 to 149.7 MW in 2024 accounting for an increase of approximately $14.2 million above the authorized base level.
- The contract for Columbia Basin Hydro was also not included in the authorized estimates, which accounted for an increase in cost of approximately $0.6 million.
- Offsetting these increased expenses was a decrease in expense related to Douglas County PUD. This reduction of approximately $1.5 million was due to the expiration of an exchange contract, which was reverted to financial settlement.

Item No. 2: Net Power Purchase Expense Rebate ($34,099,599 lower than authorized base). As previously discussed, in addition to the generation from Company-owned or operated resources, the Company considers several factors including economics, load requirements, and hydro conditions when evaluating the benefits of off-system sales. When economic to do so, the Company engages in short-term market transactions (purchases and sales), as well as long-term transactions with counterparties. For 2024, sales exceeded purchases, netting 72 aMW above what was estimated in authorized, reducing overall power supply expense by $34.1 million lower than the authorized base.

Item No. 3: Natural Gas Generation Surcharge ($473,378 lower than authorized base). This item is primarily comprised of Avista's Coyote Springs II (CS2) generating station, as well as a Power Purchase Agreement (PPA) associated with Lancaster. Also included in Avista's overall natural gas generation portfolio, categorized as "Other CT," are Boulder Park, Rathdrum, Kettle Falls CT, and Northeast Combustion Turbine. For the review period, natural gas generation was higher than anticipated in the authorized base forecast by 13 aMW. Generation at Lancaster contributed the most to this unfavorable variance, accounting for 45 aMW of the total, offset by favorable variances at both CS2 for 24 aMW and Other CT for 24 aMW.

Table No. 4 Natural Gas Generation Variance

Washington Share	aMW	Cost	Generation	Total
CS2	24	$5,624,902	($6,316,516)	($691,591)
Lancaster	-45	($4,450,062)	$11,057,630	$6,607,522
Other CT	24	$6,669,517	($13,058,848)	($6,389,307)
Total	13	$7,844,356	($8,317,735)	($473,375)

On a cost basis, natural gas generation was approximately $11.97 million above what was forecast in the authorized base. With natural gas prices remaining relatively stable throughout the year, this variance is due primarily to volume, as natural gas plants were dispatched more than anticipated in authorized and utilized to meet load obligations or for wholesale sales.

The generation variance provides more insight into the market conditions and Avista's use of its resources not only to meet customers' needs but also to optimize resources in periods when economic to do so. The value of natural gas generating resources lies not only in its availability to provide generation to load, but also in its value for facilitating wholesale market sales for the benefit of customers. As such, the value of this generation offset the increased dispatch and fuel costs, by $12.7 million for a total variance of $473,378.

Item No. 4: Thermal Generation Surcharge ($6,723,994 higher than authorized base). Thermal operations are comprised of the Colstrip Generating Station (Units 3 and 4) and the Kettle Falls Generating Station. For both combined plants, total expense exceeded authorized by approximately $6.7 million, as shown in Table No. 4 below.

Table No. 5 – Thermal Generation Reconciliation

Thermal Generation						
	Cost Variance		Generation Veriance		Total Variance	
Kettle Falls	$	1,918,083	$	(976,104)	$	941,979
Colstrip	$	2,774,347	$	3,007,668	$	5,782,015
Total	$	4,692,430	$	2,031,564	$	6,723,994

The primary contributor to the cost variance was related to price, accounting for approximately $7.1 million of the total unfavorable variances. The Colstrip fuel price is tied to several inflationary indicators which have outpaced expectations in recent years. In addition, hog fuel has escalated at a rate which outpaced the expectations included in the authorized base level of expense. When offset with a volume variance of $2.4 million, the total cost variance is $4.7 million. On a generation variance level, the lost value associated with a lower generation of 19 aMW of generation, valued at market price, was approximately $2.0 million, for a total variance of $6.7 million.

Item No. Item No. 5: Wind Generation Surcharge ($1,987,750 higher than authorized base). Wind generation is comprised of the Rattlesnake Flat, Palouse Wind and Clearwater Wind PPAs. Rattlesnake Flat and Palouse wind generated close to authorized, at 1 aMW and 6 aMW less than authorized, respectively. Clearwater wind, which came online in September of 2024 (excluding test power) was not reflected in the authorized base level of expense and thus offset these unfavorable variances by 17 aMW, resulting in a total unfavorable wind variance of 11 aMW or a total variance of $2.0 million.

Item No. 6: Other Surcharge ($6,390,978 higher than authorized base). Item No. 6, Other, is comprised of variances related to variable natural gas pipeline transportation contract expense, transmission expense, the Lancaster PPA, and miscellaneous small charges. The primary components are as follows:

- Lancaster Power Purchase Agreement - $207,000 lower costs compared to the authorized base. The Lancaster PPA includes a variable portion, and a fixed portion intended to cover Capital and Operation & Maintenance (O&M) costs. These O&M costs vary year over year dependent upon planned operations.
- Transmission Wheeling Expense - $3.1 million higher costs than the authorized base. Transmission wheeling is primarily comprised of Bonneville Power Administration (BPA) Point to Point transmission for CS2, Lancaster and Clearwater Wind. The primary increase in transmission wheeling expense is an additional contract required to move energy from the new Clearwater Wind contract, accounting for the majority of this variance.
- Miscellaneous ("other production") - $2.5 higher than the authorized base. This category is comprised of expenses such as CAISO fees, broker fees, etc. Also included in this category is approximately $655,000 of expense related to the Climate Commitment Act compliance obligations. Approximately $131,000 of this amount is related to a true-up of 2023 obligations, with the remaining $524,000 related to an estimated 2024 obligation. The Company was able to offset the majority of its wholesale sales obligation and load requirements with its no-cost allowances. However, approximately 20,000 allowances were purchased at the fourth quarter auction to cover the small remaining amount.
- Natural Gas Transportation Contracts - $1.0 million higher than the authorized base. This category reflects the impact of increases in transportation contracts for the upstream Canadian pipelines. These pipelines have annual rate adjustments and are impacted by currency exchange rate differences. These are the primary reasons for the variance in this category.

Item No. 7 Net Transmission Revenue Rebate ($12,393,503 higher than authorized base). Transmission revenue was higher than the authorized level primarily from long-term contracts that were not anticipated at the time the authorized was set. As variable energy resources increase across the Pacific Northwest (and nationally), available transmission is in high demand, resulting in increased transmission revenue for Avista. In addition, there was higher than normal short-term and non-firm use of Avista's transmission system in 2024. This increased transmission revenue helped to reduce overall net power supply expense as compared to the authorized base.

Item No. 8 Retail Revenue Credit Rebate ($3,065,189 lower than authorized base). The retail revenue credit represents the average power supply cost on a megawatt-hour basis. This rate is based on the authorized level of power supply costs as approved in the Company's most recent general rate case. From January 1 through December 31, 2024, this rate was $12.53 approved in Docket UE-220053 et. al. This rate is intended to offset the volume variance associated with the authorized level of costs.

Item No. 9 Load Surcharge ($26,537,345 higher than authorized base). As described above, the load variance was higher than authorized by 20 aMW for the year, when priced at market, which resulted in approximately $29.6 million in additional expense as compared to authorized. This additional load variance is reallocated in the variance analysis to generation which contributed to meeting load.

Q. Are there any other factors which affected the ERM Deferral for 2024?

A. Yes. In 2024, the Company tracked the revenues and expenses associated with the Solar Select Program approved by the Commission in Docket UE-180102. The net margin associated with this Program was approximately $582,149 (excluding interest) in the rebate direction. The total cumulative balance of the Solar Select program is approximately $4.4 million (including interest). The primary contributor to this net benefit is related to wholesale power prices and volumes being above what was anticipated, particularly during the Summer of 2024. The margin from the Solar Select Program flows through to customers outside of the ERM process at 100%.

VII. NEW LONG-TERM CONTRACTS ENTERED INTO IN 2024

Q. Were there any new long-term contracts that the Company executed during 2024?

A. No, there were not.

Q. Were there any PURPA Purchase Power Agreements entered into by the Company in 2024?

A. Yes, there were two new PURPA contracts that were executed in 2024. Vaagen Brothers Lumber, located in Colville Washington executed a 15-year contract of approximately 0.53 MW of capability. Avista also executed a contract with Spokane Echo District 1, LLC executed a 15-year contract for approximately 1 MW of capacity. Both contracts began providing power in 2024. In addition, there were two auto-renewing PURPAS associated with

Enel-X North America and Purcell Systems, both with a term of five years and capacity of less than 1 MW each.

VIII. THERMAL RESOURCE AVAILABILITY

Q. The 2006 Settlement Agreement in Docket UE-060181 contained several provisions for adjustments to the ERM. There were two specific requirements applicable to this filing – the first is the treatment of major plant outages and the second is regarding long term power supply contracts. Please describe how Avista is complying with the requirements regarding the first item.

A. The Settlement Stipulation contained an agreement regarding the recovery of fixed costs associated with Kettle Falls, Colstrip Units 3 and 4, and Coyote Springs II when the plants fail to meet a 70% availability factor during the ERM review period. As reflected in Table No. 5 below, no plant failed to meet a 70% availability factor.

Table No. 6 - 2024 Thermal Resource Availability

Thermal Resource Availability		
Kettle Falls	Colstrip 3 & 4	Coyote Springs II
75.1%	77.7%	94.1%

Q. Are any long-term contracts subject to the limitation for inclusion in the ERM that was part of the settlement in Docket UE-060181?

A. No. The 2006 Settlement Agreement in Docket UE-060181 regarding the continuation of the ERM included limitations on cost recovery for new or renewed contracts that are greater than 50 MW and have more than two-year term. No new long-term contracts that were in effect during the 2024 review period are subject to limitations on cost recovery.

IX. SUPPORTING DOCUMENTATION

Q. Please provide a brief overview of the documentation provided by the Company in this filing.

A. The Company maintains several documents that record relevant factors considered at the time of a transaction. The following is a list of documents that are maintained and that have been provided in electronic format with this filing:

- Natural Gas/Electric Term Deal Support: These documents record the key details of the price, terms, and conditions of a transaction. As part of Avista's workpapers accompanying this filing, the Company has provided a confidential worksheet showing each natural gas and electric term (balance of the month or longer) transaction during 2024, including all key transaction details such as trade date, delivery period, price, volume, and counterparty. Additional information can be provided, upon request, for any of these transactions.

- Position Reports: These daily reports provide a summary of transactions and plant generation and the Company's net average system position in future periods. The Daily Position Reports also contain forward electric and natural gas prices.

- ERM Variance Workpapers. This excel file is very similar to the 2024 Variance Analysis file but provides additional detail on a monthly basis.

Q. Does that conclude your pre-filed direct testimony?

A. Yes.