BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET NO. UE-22______

DIRECT TESTIMONY OF

CLINT G. KALICH

REPRESENTING AVISTA CORPORATION

I. INTRODUCTION

Q. Please state your name, the name of your employer, and your business address.

A. My name is Clint G. Kalich. I am employed by Avista Corporation at 1411 East Mission Avenue, Spokane, Washington.

Q. In what capacity are you employed?

A. I am the Manager of Resource Planning & Power Supply Analyses in the Energy Resources Department of Avista Utilities.

Q. Please state your educational background and professional experience.

A. I graduated from Central Washington University in 1991 with a Bachelor of Science Degree in Business Economics. Shortly after graduation, I accepted an analyst position with Economic and Engineering Services, Inc. (now EES Consulting, Inc.), a Northwest management-consulting firm located in Bellevue, Washington. While employed by EES, I worked primarily for municipalities, public utility districts, and cooperatives in the area of electric utility management. My specific areas of focus were economic analyses of new resource development, rate case proceedings involving the Bonneville Power Administration, integrated (least-cost) resource planning, and demand-side management program development.

In 1995, I joined Tacoma Power, where I provided key analytical and policy support in the areas of resource development, procurement, and optimization, hydroelectric operations and re-licensing, unbundled power supply ratemaking, contract negotiations, and system operations.

In 2000, I joined Avista Utilities and accepted my current position assisting the Company in resource analysis, dispatch modeling, resource procurement, integrated resource planning, and rate case proceedings. Much of my career has involved resource dispatch modeling of the nature described in this testimony.

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

A. My testimony will provide an overview of the current Power Supply methodology as developed collaboratively in workshops completed as part of Order No. 07 in Docket UE-170485 et. al. The final agreements reached through these workshops are reflected in the proposed authorized level of power supply expense included in this case. These efforts have resulted in a power supply adjustment that provides better transparency and ease of discovery for all Parties, while at the same time providing a reasonable level of expense. My testimony will describe key inputs and assumptions driving power supply costs, including loads, natural gas and electricity prices, and provides a comparison to the current level of authorized power supply expense. Finally, I will identify and explain the proposed pro forma adjustments to the 12-month ended September 30, 2021 test period power supply revenues and expenses, including the Retail Revenue Credit used in Energy Recovery Mechanism (ERM) deferral calculations.

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Q. Are you sponsoring exhibits in this proceeding?

A. Yes. I am sponsoring exhibits marked Exh. CGK-2 through Exh. CGK-6 as shown in Table No. 1 below. All are contained within one workbook in my workpapers, with all formulas and links intact for ease of reference. Information contained in these exhibits was prepared by me or at my direction.

<u>Table No. 1 – List of Exhibits</u>

Exhibit Name	Description
Confidential Exh. CGK-2C	Dispatch Model Results
Exh. CGK-3	Pro Forma and Adjustment Summary
Exh. CGK-4	Pro Forma Line Descriptions
Exh. CGK-5	Market Purchases and Sales, Plant Generation and Fuel Cost
Exh. CGK-6	Proposed Power Supply Base for ERM

II. PORTFOLIO MODELING

Q. What are the primary components of the power supply modeling methodology?

A. The Company's proposed level of power supply expense was developed utilizing the methodology agreed to as part of Docket UE-170485 et. al. This "Power Supply Methodology" was initially used as the basis for the power supply base in Avista's 2020 General Rate Case and is reflected in the current authorized level of power supply expense. The Power Supply Methodology covers seven areas affecting power cost modeling:

1. Modeling Tool
2. Source of Market Prices
3. Pricing Methodology
4. Hydro Conditions
5. AECO-to-Malin Transportation Contract
6. System Input Data
7. Data Updates 60-Days Prior to Rates Going into Effect

Q. Would you please provide further information related to <u>Item No. 1, Modeling Tool</u>?

A. Yes. Consistent with prior General Rate Cases (GRCs), the Parties agree to utilize

Energy Exemplar's Aurora software[1] to calculate the proposed authorized power supply expense. The Company has utilized this software in previous GRCs, integrated resource planning (IRP), and other power supply cost modeling scenarios since approximately 2000. Aurora will continue to be used to develop power supply costs until such time as a better tool is available. The Parties identified some changes to simplify the modeling process and make it more transparent. I will describe each change below. Specifically, Avista resources are dispatched against forward markets via "input prices", a single median water year for hydro is utilized, and certain assumptions were agreed to for modeling natural gas market spreads between the AECO and Malin trading hubs.

Q. Before addressing the pricing methodology, would you please provide further information related to Item No. 2, Source of Market Prices?

A. Yes. The Power Supply Methodology uses a three-month historical average of actual electricity and natural gas prices for the forward rate period ("forward market"). Electricity prices are represented by heavy load hours (HLH) and light load hours (LLH), priced at the Mid-C trading hub. Natural gas prices are represented as a single average price for each month, priced at the AECO and Malin trading hubs

Q. Please briefly describe Item No. 3 Pricing Methodology and the use of "input prices" in the Aurora Modeling (Model) tool.

A. In accordance with the Power Supply Methodology, the Company is using the Model with "input prices". Input prices provide the Model with hourly prices for electricity and daily prices for natural gas that reflect market conditions forecast for the rate period. Once prices are input, Avista's thermal resources are dispatched against the wholesale electric market price,

[1] The Company uses Aurora version 14.0.1059 with a Windows 10 operating system.

Avista's hydro and contractual rights and obligations are netted against test year loads to determine overall portfolio costs. When market electricity prices are lower cost than operating one or more Company resources in a given hour or hours, wholesale market power replaces that generation. Where Avista resources are available in excess of hourly loads, and one or more of those resources cost less to operate than the market price of electricity, the resources are sold into the market and the operating margin is retained to lower overall portfolio operating costs in the pro forma period. The Aurora software dispatches resources and contracts against loads using the prices input into the model, rather than Aurora generating wholesale market prices. Once resources are dispatched and market transactions are determined, all costs are summed, as provided for in Exh. CGK-3.

Q. Would you please explain how are prices shaped in the Model?

A. Yes. Monthly forward HLH/LLH electricity prices are translated to hourly prices used by Aurora, and monthly forward natural gas prices are shaped to daily prices. Prices are created by breaking out the periods algebraically and shaping them based on actual test year prices. Weekdays are shifted as necessary to align the test and rate years. This means that if the rate year begins on Tuesday, but the test year begins on Monday, the test year data will be shifted one day so that the weekdays line up. Should the historical test year contain volatility from extraordinary events not expected to occur in the normalized test year, an adjustment removes such events, and the filing documents the adjustment.[2] The calculations result in hourly electricity prices for the proforma period, such as 744 hours for the Mid-C in January, split between HLH and LLH. AECO and Malin natural gas prices are calculated similarly using the

[2] For example, the Heat Dome event in the Pacific Northwest in June/July 2021 was considered in the Weather Normalization adjustment (https://www.spokesman.com/stories/2021/jul/08/weathercatch-heat-wave-remains-hot-news-heres-why/).

Malin daily price shapes, as natural gas spot market trades are reported as a single price for each day.

Q. What changes are made by the Company to the Aurora Model in order to effectuate the "input prices" methodology?

A. The Model was not originally designed to operate as a "closed" single-utility system with input prices; however, the software is capable of using input prices with the appropriate system setup adjustments. Specifically, adjustments include the setup of a single zone with Avista loads, contracts and resources. In addition, a single large load (Mid-C Market Load) is added to the zone, as is a single large resource (Mid-C Market Resource). The price of the Mid-C Market Resource equals the input electricity price in each hour. The single Mid-C Market Resource is big enough to meet the Mid-C Market Load plus Avista's load, essentially creating a "market" for Avista to dispatch its resources against.

Q. When you say a "single large load (Mid-C Market Load)," what do you mean?

A. The Mid-C Market Load must be big enough to absorb all potential surplus sales from Avista resources when they are lower cost to operate than the market price of power and are surplus to Avista's loads. The Mid-C Market Resource must meet all of the Mid-C Market Load plus potential Avista deficits created by dispatching down resources having operating costs above market prices in any period. For simplicity, Avista elected to create a Mid-C Market Resource with a capacity equal to twice our maximum hourly annual balancing area load in the pro forma period, or 4,274 MW. For the Mid-C Market Load, Avista elected to create a load in each hour equal to twice Avista's area load in the same hour.

Q. Does creating the Market Resources affect power supply costs?

A. No. Irrespective of the size of the Mid-C Market Resource, so long as it is at least large enough to absorb all surplus power from Avista's generation portfolio, it has no impact on power supply costs.

Q. Does creating the Mid-C Market Load change how resources are dispatched in the Model?

A. No, because of the approach used. The Model dispatches hydro against the shape of all loads in the load area. A Mid-C Market Load that is the same in all hours (e.g., 5,000 MW in each hour of the rate period) would change the area load shape and therefore affect the hydro generation profile. By shaping the Mid-C Market Load the same as Avista's load, hydro continues to dispatch to the shape of our loads and equals the same five-year average on-peak and off-peak shapes by month. Non-hydro resources are not affected in any way by the size of the Mid-C Market Load.

Q. Please provide additional description on how Avista's resources are dispatched in the Model.

A. In each hour where the Mid-C Market Resource price is higher than operating one or more Avista resources, the Avista resource, or resources, is dispatched. Load not served by Avista resources in the hour, if any, is served by the Mid-C Market Resource with a cost equal to the input market price. If dispatched Avista resources exceed Avista's load in the hour, the extra power displaces a portion of the Mid-C Market Resource serving the Mid-C Market Load, and this revenue is credited to lower pro forma power supply costs. In this way Avista's resources and loads are valued at the electricity prices input into the Model.

Q. Specific to the Pro-Forma Period, what prices are being utilized in the Model?

A. Following the agreed-upon pricing methodology, forward electricity and natural gas prices use the three-month average (approximately 60 market settlement days) of Intercontinental Exchange (ICE) prices from July 1, 2021 through September 30, 2021, the date range up to the point where Avista began modeling its costs for this case. As previously discussed, prices are shaped hourly for electricity and daily for natural gas, reflecting how these spot markets traded in the test year and will trade in the pro forma year. For example, if during the 12-months ended September 30, 2021, the Mid-Columbia electricity price in the first hour of January is 90 percent of the average January price in the test year, then the Mid-Columbia input price to the Model for that hour is equal to 90 percent of the January 2023 forward price. Similar math is performed for natural gas, but because the spot market for natural gas is based on daily pricing, the shape is done daily using the Malin daily test year shape. Backup for the price calculations can be found in my workpapers.[3] Table No. 2 below details the prices input into the Model affecting our resources.

Table No. 2 – Monthly Forward Prices at Key Hubs

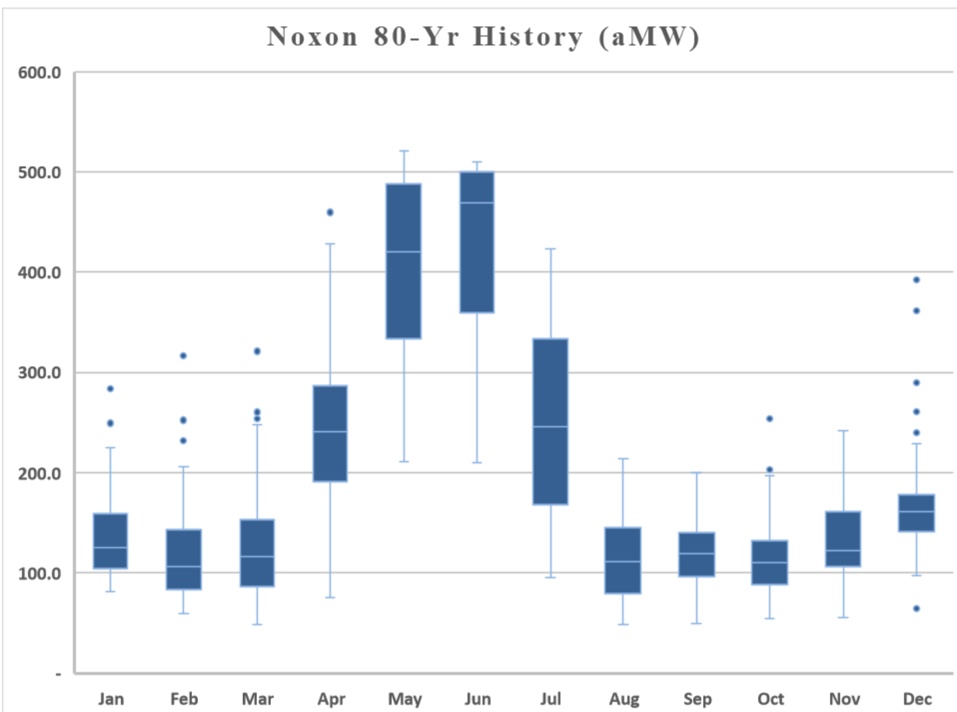
	Price $/dth		Price $/MWh	
Basin	**AECO**	**Malin**	**Mid-C Off**	**Mid-C On**
Jan-23	2.86	4.11	46.08	54.44
Feb-23	2.83	3.99	40.63	47.17
Mar-23	2.57	3.54	34.30	39.32
Apr-23	2.17	2.59	22.65	27.49
May-23	2.04	2.52	16.82	25.63
Jun-23	2.04	2.56	14.91	25.85
Jul-23	2.10	2.81	42.90	81.37
Aug-23	2.11	2.83	51.86	95.16
Sep-23	2.11	2.83	42.03	76.97
Oct-23	2.16	2.73	34.01	39.78
Nov-23	2.32	3.27	36.76	43.30
Dec-23	2.46	3.53	43.70	52.56
Avg	2.31	3.11	35.55	50.75

[3] See Kalich workpaper: NaturalGas_Elec_Prices.xlsx, to be provided to the Parties shortly after this case is filed with the Commission.

Q. Would you please provide further information related to <u>Item No. 4, Hydro Conditions</u>?

A. Yes. In accordance with the agreed upon Power Supply Methodology, a single year of median monthly values from the eighty-year water record is determined using the full hydro record for each project. Graph No. 1 below depicts the eighty-year record and median values for our largest hydroelectric resource, Noxon Rapids, on the Clark Fork River. Supporting data for the chart, as well as similar data and charts for our other hydro plants and Mid-C contracts are in my workpapers.

<u>Graph No. 1 – Monthly Median Water at Noxon Rapids</u>



Q. How does the Model operate Company-controlled hydroelectricity generation resources?

A. To account for actual flexibility of Company hydroelectricity resources, Avista develops individual operation logic for each of the river systems. This separation ensures the flexibility inherent in these resources is credited to customers in the pro forma exercise using generation profiles for each river system closely matching the latest five-year average (through 2020 in this case).

Q. Please compare the operating statistics from the Model to recent historical hydroelectricity plant operations.

A. Over the pro forma period, the Model generates 68% of Clark Fork generation during on-peak hours. Since on-peak hours represent only 57% of the year, this demonstrates a substantial shift to the more expensive on-peak hours. This dispatch approximates the five-year average of on-peak generation at the Clark Fork. Avista ensures this historical shaping by river system for each month. Data supporting these calculations are in my workpapers.[4]

Q. How are reserves modeled?

A. At this time, Avista does not implicitly represent reserves in the Model, though the Company employs two methods to reflect reserves. The first is the use of five-year hydro shaping. This shape reflects the operations of our hydro plants over time and how they are impacted by providing reserves. The second method is limiting the dispatch of our Northeast and Rathdrum gas plants, just as our operations and trading teams do in actual operations. I will discuss the impacts reserves place on our thermal fleet later in my testimony.

Q. Would you please provide further information related to <u>Item No. 5, AECO-to-Malin Transportation Contracts</u>?

A. Certainly. Avista's thermal operations rely on long-term firm transportation contracts from the AECO basin in Alberta, Canada, to Kingsgate at the U.S. Border, and from

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[4] See Kalich workpapers: Hydro History_ClarkFork.xlsx, Hydro History_Spokane.xlsx, Hydro History_MidC.xlsx.

Kingsgate to multiple points south, terminating at the Malin basin located in Oregon.[5] The Power Supply Methodology calls for Aurora to dispatch Avista's electric generation plants using a "landed" natural gas price based on Malin. The landed price is derived in most cases by discounting the Malin forward price with fuel loss, delivery, and tax charges associated with delivery to each plant. A spreadsheet model reduces natural gas fuel cost from the Aurora plant dispatch due to lower AECO prices up to the contractual rights Avista holds from AECO and Kingsgate. As with previous cases, our natural gas-fired plants continue using this methodology. In addition, Surplus transportation capacity not used for dispatch is valued using the spread between AECO and Malin, consistent with overall market prices. This spreadsheet model is included in my workpapers.

Q. Would you please provide further information related to <u>Item No. 6, System Input Data</u>?

A. Yes. The Power Supply Methodology continues past practice, namely using five-year averages for forced and planned maintenance outages, hydro shaping, and variable and small (e.g., PURPA) contract generation levels, and various other data that are not known with near certainty due to year-to-year variability. Various other miscellaneous expenses, such as broker fees, CAISO sales, transmission revenues, etc. also use a five-year average when five years of data is available. For plants where two maintenance cycles exceed the five-year window (i.e., Colstrip), an average of outage rates over the past two cycles is used. Finally, extraordinary events are removed from the averaging described above when adequate justification for such removal exists. Backup for such calculations are included in my workpapers provided to the

[5] Avista has approximately 61,000 dekatherms per day of natural gas transportation rights from AECO. Lancaster and Coyote Springs 2, our efficient combined cycle gas turbines when operating together exceed this amount. Total natural gas consumption across the fleet during peak days approaches a demand level of twice our contractual rights from AECO.

parties in this case.

Q. Please provide further information related to <u>Item No. 7, Data Updates 60-Days Prior to Rates Going in Effect</u>.

A. As outlined in the Power Supply Methodology, certain power supply model data will be updated 60-days prior to rates going into effect in an effort to lessen variability and improve accuracy, as detailed below:

- Wholesale natural gas and electricity prices
- Non-gas fuel prices (i.e., wood, coal)
- Incremental short-term contracts for natural gas and electricity
- Power and transmission service contract affecting the rate year

These updates provide a refresh of natural gas prices and electric market prices, non-natural gas fuel prices where such prices are the result of a contract, the addition of all new incremental contracts with terms less than one year affecting the pro forma period, and any known rate changes to power and transmission service contracts in the filing.

Q. Is the Company proposing any modification to the 60-day update method given this filing is for a multi-year rate plan?

A. Yes. The Company is requesting approval in this proceeding for a trigger, as discussed below, which would allow Avista to file, for Commission review and approval, a 60-day update to its baseline power supply costs <u>prior to Rate Year 2</u> should power supply costs increase or decrease by 10% from the authorized base for Rate Year 1 (or approximately $14 million system).

The purpose of the Rate Year 2 power supply update is to ensure that any significant changes in power supply expenses are included in base rates. As it currently stands, at the point of the 60-day update provided prior to Rate Year 1, costs are estimated for more than two years forward. This lead time is likely too long to adequately capture future market conditions or contract changes. It will not take into account the impacts of other substantial changes in power supply expense, such as the Chelan Hydro contract discussed in Company witness Mr. Thackston's testimony, or other changes in future market conditions such as natural gas prices, power prices and regional carbon market integration.

The Company recognizes there is some level of variability which is appropriate in the ERM mechanism. However, the use of the trigger mechanism allows the Company to proactively make adjustments for changes which could, in aggregate, substantially impact power supply expenses from the level included in the final power supply expense for Rate Year 1.

Q. Would an update to Energy Imbalance Market (EIM) benefits also be part of the Rate Year 2 power supply update?

A. It is unlikely that enough historical data will exist to inform the filing, given Avista will only have been an EIM participant for a year and a half by the time an update would be filed with the Commission. If Avista does experience a significant divergence and/or there is a methodology put in place for estimating EIM revenues between this case and the proposed update, the Company is open to revisiting the EIM line item. In any event, if the Commission allows Avista to file a 60-day update for Rate Year 2 for its consideration, Avista would provide information on the level of EIM benefits and incorporate an adjustment if a change to that benefit level is appropriate. Company witness Mr. Kinney provides further information on EIM, including benefits, in his direct testimony.

Q. Has the Company included the potential impact of the Cap-and-Invest Program within the Washington Climate Commitment Act (CCA) in its modeling (RCW 70A.65)?

A. No. It is not possible to recognize CCA legislation impacts in modeled power costs until the Department of Ecology finalizes its CCA rulemaking. Avista continues to monitor and participate in CCA rulemaking efforts and will incorporate changes to the Company's rate case modeling when possible, likely later this year. As Avista learns more, it will engage appropriate stakeholders as necessary to provide an overview of the new rules, and review and gain consensus around methodology changes necessary to reflect CCA cost and operational impacts in our power supply modeling.

Q. Do you expect the CCA costs will impact Rate Year 1 or Rate Year 2 power supply expense?

A. Yes, with the law goes into effect on January 1, 2023, and therefore its effects will impact our operations at that time (which is also roughly the beginning of Rate Year 1). Avista will be given a limited supply of allowances beginning in 2023 to offset its greenhouse gas emissions. This limit will increase power supply cost due to (1) reduced thermal plant dispatch and changes to market purchases/sales when accounting for the cost of emissions price and (2) the cost of additional allowances beyond those assigned to the Company that may be required.

Q. What method would the Company use to estimate Rate Year 1 and Rate Year 2 power supply expenses?

A. Generally, Avista would use the same 60-day update methodology used for Rate Year 1 would be used for Rate Year 2. To the extent costs can be reasonably estimated, Avista will model the impacts of the CCA in the 60-day update. Beyond CCA, in Rate Year 2 if an adjustment is (1) needed and (2) allowed by the Commission, Avista would also include the new Chelan PPA discussed in Mr. Thackston's testimony, which begins in 2024. Finally, if an adjustment is needed for Rate Year 2, the Company also will incorporate, if appropriate, a different level of EIM benefits as noted earlier.

III. OTHER KEY MODELING ASSUMPTIONS

Q. What other key modeling assumptions are being made by the Company?

A. Other modeling assumptions driving Aurora-modeled pro forma costs are forecasted loads and forced and planned maintenance outages at Avista plants.

Q. What is the Company's assumption for rate period loads?

A. Consistent with prior GRC proceedings, historical loads are weather-adjusted. For this filing, weather-normalized calendar year 2023 load is 1,045.5 average megawatts compared to actual test period loads of 1,061.2 average megawatts. Table No. 3 below details data included in this proceeding. Please see Company witness Mr. Garbarino's testimony (Exh. TLK-1T) for additional information on weather normalization.

Table No. 3 – Historical Loads

Month	Test Year Load (MW)	Weather Adjustment (MW)	Modeled Load (MW)
Jan-23	1,149.1	43.7	1,192.8
Feb-23	1,220.1	-32.3	1,187.8
Mar-23	1,052.2	17.9	1,070.1
Apr-23	942.0	18.0	960.0
May-23	919.5	10.9	930.4
Jun-23	1,093.3	-144.8	948.5
Jul-23	1,175.3	-135.6	1,039.7
Aug-23	1,055.1	-16.1	1,039.0
Sep-23	921.7	-0.8	921.0
Oct-23	956.5	1.9	958.4
Nov-23	1,079.0	9.3	1,088.2
Dec-23	1,179.1	35.7	1,214.8
Total	1,061.2	-15.7	1,045.5

Q. What are the assumed forced outage and planned maintenance rates for your fleet?

A. Consistent with the Power Supply Methodology, five years of data (through 2020) were used to calculate average forced and planned outage rates at each of our plants (except Colstrip maintenance). Table No. 4 below details these rates and compares them to our 2020 GRC filing.

Table No. 4 – Forced and Maintenance Outage Rates, 2022 and 2020 filings

	Forced Outage Rate			Maintenance Rate		
Facility	**2022**	**2020**	**Difference**	**2022**	**2020**	**Difference**
Boulder Park	5.8%	5.8%	0.0%	5.0%	n/a	5.0%
Colstrip	11.4%	10.4%	1.0%	6.0%	4.3%	1.7%
Coyote Springs 2	2.8%	2.8%	0.0%	9.1%	7.4%	1.7%
Kettle Falls	2.7%	2.2%	0.5%	13.6%	13.0%	0.6%
Kettle Falls CT	2.9%	2.2%	0.7%	4.3%	3.5%	0.8%
Lancaster	2.2%	2.2%	-0.1%	6.2%	5.9%	0.3%
Northeast	0.9%	0.9%	0.0%	n/a	n/a	n/a
Rathdrum	4.7%	4.7%	0.0%	6.1%	n/a	6.1%

Q. Please discuss your outage assumptions for Colstrip Units 3 and 4.

A. Consistent with the Power Supply Methodology, given the planned maintenance cycle for Colstrip is four years, we used the recent eight-year average (through 2020) to include two 4-year maintenance cycles.

Q. Are the Rathdrum and Northeast natural gas-fired plants modeled differently in this case than in the past?

A. Yes. Rathdrum and Northeast natural gas-fired plants provide most of our contingency and standby-reserve capabilities. Both are high heat rate facilities, meaning they are not expected to run at high levels over a year and their operating margins are relatively low. Northeast, even if cost-effective to run relative to market prices, is limited to 100 hours per year due to regulation by the Spokane Regional Clean Air Agency. As such, Northeast is modeled to be set aside exclusively to meet operating reserve requirements, consistent with our last general rate case.

Northeast, on a stand-alone basis, is not large enough to meet our contingency requirements. As such, one Rathdrum unit is typically set aside by Avista's trading floor operations for reserves purposes, even when market conditions show it to be lower cost than buying from the market power. To reflect Rathdrum operations, the Model sets aside one (of the two) Rathdrum units for contingency reserves during April through July when the hydro system has inadequate reserve capacity to supplement Northeast. This modification provides a modest benefit relative to the last case where we set aside the unit for the entire year. Lost margins, and therefore overall power supply expenses, are lower in this filing by approximately $0.8 million relative to our 2020 GRC with that change. Table No. 5 below details energy and lost margins resulting from these modeling changes.

Table No. 5 – Northeast and Rathdrum Reserves Set-Aside Lost Margins

	Rathdrum	Northeast	Other Units	Total
Total Energy Revenue	$ (3,823)	$ (797)	$ 4,141	$ (479)
Fuel	$ 1,882	$ 590	$ 193	$ 2,665
Lost Margins	$ (1,941)	$ (207)	$ 4,334	$ 2,186
MWh (reserve)	61,944	12,987	-	74,931

Q. What are the contingency and standby reserve requirements Avista must retain that removes these resources from dispatching when market prices would otherwise allow?

A. Avista's participation in the Northwest Power Pool Reserves Sharing Agreement requires us to carry three percent each of online generation and load as contingency reserves. Our modeled average pro forma generation of over 1,300 megawatts (MW) and average pro forma load of 1,045 MW necessitate approximately 75 MW of average contingency reserves.

The amount of what Avista terms standby reserves are a bit more arbitrary than contingency reserves, as they are not defined by agreement. Standard industry practice dictates that a utility should stand prepared for times when it loses its largest single generator–both with capacity and fuel. For Avista, depending on system conditions, our largest generator could be a smaller hydro unit at our Clark Fork Project (75-150 MW range), or it could be one of our large natural gas plants like CS2 generating up to 300 MW or more.

Taken together, the contingency and standby reserves statistics described above, as they relate to proforma dispatch, range between 74.5 and 405 MW, with an average of 325.3 MW, and require the reservation of fuel to generate electricity. The combination of Northeast and a single unit at Rathdrum approximate the minimum range but is well below the average and maximum of this range. We generally supplement the quantities above with hydro unit capability, in order to have appropriate reserves in our power supply modeling. Support for this can be found in my workpapers.

Q. Please describe any changes to power contracts since the 2020 General Rate Case filing and their impacts on power costs.

A. Avista updates all contracts over the pro forma term to account for expiring and new contracts. Any contract without a known and/or fixed schedule is represented with a five-year historical average (e.g., PURPA contracts).[6] Table No. 6 below lists all contract changes in this case since the 2020 GRC.

[6] When five years of history are not available a lesser number of years may be used. For new resources, such as Rattlesnake Wind, the vendor's forecast is used until such time an adequate history exists.

Table No. 6 – Wholesale Contract Changes (MWa)

Contracts	Ann	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Chelan PUD	-	-	-	-	-	-	-	-	-	-	-	-	-
Douglas PUD	2.4	3.6	3.0	1.5	2.5	3.2	3.2	2.8	2.3	1.2	1.2	1.6	3.1
Grant PUD	(0.0)	-	-	-	-	-	-	-	-	(0.0)	-	-	-
Douglas Exchange Purchase	-	-	-	-	-	-	-	-	-	-	-	-	-
Canadian Entitlement	(0.9)	(1.0)	(1.0)	(1.0)	(0.7)	(1.2)	(1.0)	(1.0)	(1.0)	(1.0)	(1.0)	(1.0)	(0.7)
Nichols Pumping	-	-	-	-	-	-	-	-	-	-	-	-	-
Palouse Wind	2.0	7.8	3.5	0.8	5.5	1.8	0.8	(1.6)	(0.4)	1.5	2.5	3.6	(2.0)
Rattlesnake Wind	-	-	-	-	-	-	-	-	-	-	-	-	-
Adams Neilson Solar	-	-	-	-	-	-	-	-	-	-	-	-	-
Small Power	(0.0)	(0.3)	(0.7)	(0.2)	(0.1)	0.1	0.3	0.5	0.1	0.0	0.0	0.1	(0.2)
Spokane Waste-to-Energy	0.3	0.6	(0.5)	0.3	0.1	(0.6)	0.9	0.4	(0.4)	(0.1)	(0.0)	0.4	2.1
Stimson Lumber	0.2	0.3	0.3	0.2	-	0.2	0.7	0.2	(0.3)	0.2	0.1	(0.1)	0.1
Upriver	0.2	(1.2)	0.2	(0.8)	0.3	0.5	2.0	0.7	0.1	0.1	0.4	0.6	(0.3)
Douglas Exchange	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Contracts	**4.1**	**9.8**	**4.9**	**0.8**	**7.6**	**4.0**	**6.9**	**2.0**	**0.5**	**2.0**	**3.3**	**5.2**	**2.1**

Q. Were there any large components worth highlighting in the table?

A. No, there are not. Since the last case, two small power contracts—Spokane County Digester and Great Northern Solar—have new contracts in which they are now net-metered and in the unlikely event these customers generate over the amount of their load, compensation for the energy is at market rates. Because of the expectation that there will not be any surplus generation purchased from these customers, the PPAs are not modeled in the proforma year.[7]

Q. Are there other contracts not included in the Model?

A. No, there are not. As with past filings, we do not model index contracts because they have no impact on power supply costs. Regardless, there were no short-term deals in this pro forma period.

Q. How is the Adams-Neilson Solar project treated in this filing?

A. Adams-Neilson Solar, sometimes referred to also as Lind Solar, exclusively

[7] The City of Spokane Waste-to-Energy and Upriver Dam 15-year contracts are in the process of the final stages of negotiation with new contracts effective January 1, 2023. The contract prices included in this filing represent the final agreed-upon rate. These contracts are modeled at the historical five-year average energy output.

serves the Solar Select program whereby self-electing customers use its energy to serve their loads. In the Model it is offset with a sale at the same contract price, removing any impact on power supply expense. The Company believes it is appropriate to maintain the contract in our modeling costs for ease of calculation when the current Solar Select program ends. Costs for this resource and the Solar Select program are accounted for separately in the annual ERM filing. Once prudency has been determined, it is transferred to the ERM balance for future return to customers.

Q. How are thermal fuel expenses for non-gas resources determined in the pro forma?

A. Non-gas fuel is procured for Colstrip and Kettle Falls Generating Station. Avista's coal fuel supply agreement unit price is dependent on the amount of coal purchased each year. The Model estimates the amount of coal dispatch in the pro forma period based on an estimated price from Avista's position report. After the Model dispatches the plant, our coal supply contract prices are applied to that dispatch. Wood fuel costs at Kettle Falls are based on our contracts with fuel suppliers and inventory. The total fuel cost is determined similarly to Colstrip; expected Model dispatch is priced using budgeted prices for our fuel supply contracts. Fuel cost calculations can be found in my workpapers.

IV. MODELING RESULTS

Q. Please summarize the results from power supply modeling.

A. The Model tracks our portfolio during each hour of the pro forma study. Many of the modeling results are shared earlier in my testimony. Overall fuel costs and generation for each resource are calculated and summarized in Confidential Exh. CGK-2C and Exh. CGK-3.

Market sales and purchases, and their revenues and costs, are determined as well and shown in Table No. 7 below (as shown in Exh. CGK-5).

Table No. 7 – System Balancing Sales & Purchases

Item	**2022 GRC**	**2020 GRC**	**Delta**
	aMW	**aMW**	**aMW**
Market Purchases	8.9	9.7	(0.8)
Market Sales	(342.5)	(319.0)	(23.5)
Net	(333.6)	(309.3)	(24.3)
	$/MWh	**$/MWh**	**$/MWh**
Market Purchases	42.04	33.33	$8.71
Market Sales	-41.51	-38.10	($3.41)
Net	-39.39	-35.99	($3.40)
	($000)	**($000)**	**($000)**
Market Purchases	3,281	2,832	449
Market Sales	(124,551)	(106,460)	(18,091)
Net	(121,270)	(103,628)	(17,642)

Market transactions, when combined with other resource and contract revenues and expenses not accounted for directly in the Model (e.g., fixed costs), determine the total net power supply expense.

V. OVERVIEW OF PRO FORMA POWER SUPPLY ADJUSTMENT

Q. Please provide an overview of the pro forma power supply adjustment.

A. The pro forma power supply adjustment reflects revenues and expenses from the Model-defined dispatch of Avista resources, combined with wholesale market transactions under weather-normalized load and median hydro conditions. In addition, adjustments are made to reflect contract changes between the historical test year and the pro forma period and for estimated gas transportation optimization.

Q. Please identify the specific power supply cost items not included in the Model

but affect the total adjustment being proposed.

A. Besides costs determined by the Model, Exh. CGK-3 identifies non-modeled power supply expense and revenue items. These relate to fuel expenses, transmission expense, and other miscellaneous expenses and revenues associated with our power supply business.

Q. What is the basis for the adjustments to the test period power supply revenues and expenses?

A. As explained earlier in my testimony, the test period is adjusted to normalize power supply expenses for normal weather and median hydroelectricity generation. It also reflects the same forward electricity and natural gas prices used in the Model. It includes other known and measurable changes expected during the pro forma period. A brief description of each adjustment in Exh. CGK-3 is provided in Exh. CGK-4. Detailed workpapers will be provided to the Parties shortly after this case is filed with the Commission supporting the pro forma revenues and expenses. Each line in Exh. CGK-3 shows actual revenue or expense in the test period, the pro forma revenue or expense, and the delta between the two.

Q. What actual forward-term transactions are included in the pro forma?

A. Typically, the pro forma includes actual term transactions affecting the pro forma period, however, there are no such transactions for this pro forma period. The Model is used to value all physical and financial electricity transactions when present in the pro forma period, but is not able to model the natural gas side of our business. For natural gas, a set of mark-to-model calculations are performed outside the Model, transferred to Exh. CGK-3 and supported in workpapers.

Q. Please summarize the Company's Pro Forma Power Supply Adjustment.

A. The table below shows total net power supply expense during the test period and the pro forma periods. For information purposes, the power supply expense currently in base rates is shown in Table No. 8 below.[8]

Table No. 8: Pro Forma Power Supply Adjustment Summary

Measure	System[(1)]	Washington Allocation[(2)]
	($000s)	($000s)
Test Period Authorized Power Supply Expense [(3)]	$171,699	$ 111,692
Actual 12ME 9/30/21 Test Period Power Supply Expense	$184,704	$ 121,055
Proposed 2023 Pro Forma Power Supply Expense	$139,049	$ 91,133
Proposed 2023 Expense versus 12ME 9/30/21 Test Period	$ (45,655)	$ (29,922)
Current Authorized Power Supply Expense effective 10/1/21	$136,699	$ 89,729
Proposed 2023 Expense versus Current Rates [(4)]	$ 2,350	$ 1,403

(1) Excludes Transmission - see Company Witness Schlect and adjustment 3.00T. Includes load and settlement adjustment.
(2) Allocated based on ROO Current Production/Transmission Ratio of 65.54.
(3) Adjusted for current weather normalized loads.
(4) Incremental impact compared with current rates effective 10/1/21.

The net effect of my adjustments versus the test year power supply expense is a *decrease* of $45.6 million on a system basis, or $29.9 million for Washington. However, as compared with current rates effective October 1, 2021, the incremental effect of my adjustments **versus current authorized power supply expense** is an *increase of* $2.35 million on a system basis, or **$1.4 million for Washington**.

VI. ERM AUTHORIZED VALUES

Q. What is Avista's proposed authorized power supply expense and revenue for the ERM?

A. As shown in Table No. 8, the proposed authorized level of annual system power

[8] For the remainder of my testimony, for purposes of the power supply adjustment, I will refer to the net of power supply revenues and expenses as power supply expense for ease of reference.

supply expense is $91.1 million (Washington-basis) for the pro forma period, excluding transmission revenues (sponsored by Company witness Mr. Schlect). This is the sum of Accounts 555 (Purchased Power), 501 (Thermal Fuel), 547 (Fuel), less Account 447 (Sale for Resale). Exh. CGK-6 provides the proposed authorized level of annual system power supply expense detail, including transmission expense, transmission revenue and various other expenses and revenue.

Q. What is the proposed Retail Revenue Adjustment for the ERM?

A. The proposed authorized level of retail sales to be used in the ERM is the 12-months ended September 30, 2021 weather-adjusted Washington retail sales. The proposed Retail Revenue Adjustment rate is $12.53 per MWh for the pro forma period, the FERC Account average cost in the power supply pro forma. These values may be found in Exh. CGK-6.

Q. Has Avista proposed to update power supply costs as a part of this case?

A. Yes. In Avista's 2017 general rate request (Docket UE-170485), the Commission stated in its Final Order 07 that baseline adjustments to power supply costs should only be made "in extraordinary circumstances." More specifically, the Commission stated:[9]

> … the Commission believes the number of recent baseline adjustments is excessive. … Moving the baseline upward or downward in each general rate case results in distorted results. Going forward, the Commission will consider carefully any adjustments to the power cost baseline and change it **only in extraordinary circumstances**. (emphasis added)

In this case, we view that power supply costs should be adjusted due to "extraordinary" circumstances. Those "extraordinary" circumstances are not, however, related to the proposed level of power supply cost in comparison to the current authorized level of power supply expense which went into effect October 1, 2021.

[9] Dockets UE-170485 and UG-170486, Order 07, ¶160.

What makes this adjustment "extraordinary" is that this is the first Two-Year Rate Plan filed under SB 5295, and the new CCA goes into effect. It is important, in our view, to file a power supply base that is more representative of the rate effective periods. The power supply base would incorporate power market conditions and pricing that is almost 15 months "fresher" than what is included in embedded power supply costs today. Additionally, the new power supply base properly accounts for an annualized amount of EIM benefits (discussed by Mr. Kinney), CCA impacts, and transmission revenues (discussed by Mr. Schlect), among other changes. While the overall change in the power supply base presently is smaller than the changes in our last general rate case, it is important both to update base power supply in this case, and potentially update them again for Rate Year 2 where estimated costs vary by more than ten percent.

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

A. Yes, it does.