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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION	)	CASE NO. AVU-E-23-01
OF AVISTA CORPORATION FOR THE	)	CASE NO. AVU-G-23-01
AUTHORITY TO INCREASE ITS RATES	)	
AND CHARGES FOR ELECTRIC AND	)	DIRECT TESTIMONY
NATURAL GAS SERVICE TO ELECTRIC	)	OF
AND NATURAL GAS CUSTOMERS IN THE	)	CLINT G. KALICH
STATE OF IDAHO	)	
	)	

FOR AVISTA CORPORATION

(ELECTRIC ONLY)

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 Senior Manager of Resource Analysis in the Energy Supply 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 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 late 1995, I left Economic and Engineering Services, Inc. to join Tacoma Power in Tacoma, Washington. 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. I helped develop, and ultimately managed, Tacoma Power's industrial market access program serving one-quarter of the Company's retail load.

In mid-2000 I joined Avista Utilities and accepted my current position assisting the Company in resource analyses, 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 includes documentation of the rationale for key inputs and assumptions driving power supply cost values including loads, natural gas and electricity prices, and a comparison to current levels of authorized power supply expense. I will provide an overview on contract changes since our last filing, including our newly signed Columbia Basin Hydro contract, and discuss Washington State's new Climate Commitment Act (CCA) and how its limitations on thermal plant carbon emissions affect Idaho costs. Finally, I will identify and explain the proposed pro forma adjustments to test period power supply revenues and expenses, including the Retail Revenue Credit used in the Power Cost Adjustment (PCA).

A table of contents for my testimony is below:

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring Confidential Exhibit No. 7, Schedules 1 through 5, as shown in Table No. 1 below. Confidential Schedule 1C and Schedules 2 through 5 are contained within one workbook in my workpapers, with all formulas and links intact for ease of reference. Schedules 1C, 2, 4 and 5 have two exhibits each, one for each rate year. In addition to these schedules, sheets after them in the workbook provide detail and supporting calculations. Information contained in these exhibits were prepared by me or at my direction.

Table No. 1 – Confidential Exhibit No. 7 List of Schedules

Schedule Name	Description
Confidential Schedule 1C RY1/RY2	Dispatch Model Results
Schedule 2 RY1/RY2	Pro Forma and Adjustment Summary
Schedule 3	Pro Forma Line Descriptions
Schedule 4 RY1/RY2	Market Purchases and Sales, Plant Generation and Fuel Cost Summary
Schedule 5 RY1/RY2	Proposed Power Supply Base for PCA

II. DISPATCH MODEL

Q. Has the Company made any changes to the overall Portfolio Modeling Methodology used in this case as compared to the last general rate case?

A. No. We are using the same methodology as our 2021 General Rate Case filing, Case No. AVU-E-21-01, including using Aurora (Model) to optimize Company-owned resource and contract dispatch during each hour of pro forma year.

Q. What experience does the Company have using Aurora?

A. The Model has been at Avista since April 2002 and used for numerous studies including each of our integrated resource plans and rate filings after 2002. We also use Aurora for various resource evaluations, market forecasting and requests-for-proposal evaluations.

Q. Please briefly describe how the Model is used in this case.

A. The Company uses the Model with "input prices". Using input prices instead of Aurora-generated prices allows the Model to optimize against prices input by Avista for electricity and natural gas that reflect market conditions forecast for the rate period. Using this method, prices more accurately reflect current forward prices in the wholesale marketplace, the overall modeling process is simplified, and greater transparency is possible.

Once prices are input, the Model dispatches resources and contracts against wholesale electric market prices and load obligations to determine net variable costs. When market electricity prices are lower than operating one or more Company resources in each hour or set of hours, wholesale market power purchases displace that generation. Where Avista resources exceed 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, lowering power supply cost for the pro forma period. Once resources are dispatched and market purchases and sales are determined, all costs are summarized into my Confidential Exhibit No. 7, Schedule 2. Market Purchases and Sales, Plant Generation, and Fuel Cost Summary is provided as Confidential Exhibit No. 7, Schedule 4.

Q. What are the prices input into the Model?

A. Forward electricity and natural gas prices use the one-month average of Intercontinental Exchange (ICE) prices from October 3, 2022 through November 1, 2022, the date range up to the point where Avista began modeling its costs for this case.[1] Table No. 2 below details the prices input into the Model affecting our resources.

[1] A trading month contains approximately 20 trading days.

Table No. 2 – Monthly Forward Prices at Key Trading Hubs

Period	AECO ($/dth)	Malin ($/dth)	Mid-C LLH ($MWh)	Mid-C HLH ($/MWh)	Period	AECO ($/dth)	Malin ($/dth)	Mid-C LLH ($MWh)	Mid-C HLH ($/MWh)
Sep-23	3.016	4.691	72.84	167.17	**Sep-24**	2.900	4.099	69.81	127.59
Oct-23	3.135	4.541	62.61	86.23	**Oct-24**	3.027	4.034	51.16	71.64
Nov-23	3.633	5.387	68.75	93.70	**Nov-24**	3.422	4.622	55.65	77.66
Dec-23	3.967	6.091	78.36	108.18	**Dec-24**	3.725	5.430	66.80	95.19
Jan-24	4.043	6.205	69.74	105.11	**Jan-25**	3.817	5.395	79.47	93.23
Feb-24	4.015	5.873	62.10	91.35	**Feb-25**	3.758	5.328	70.02	80.17
Mar-24	3.559	4.820	50.85	73.81	**Mar-25**	3.447	4.701	57.94	65.97
Apr-24	2.943	3.797	38.12	47.19	**Apr-25**	3.175	3.812	34.13	44.65
May-24	2.804	3.708	32.71	45.03	**May-25**	2.977	3.711	29.11	42.36
Jun-24	2.827	3.793	31.30	45.26	**Jun-25**	3.018	3.842	28.68	43.85
Jul-24	2.844	4.103	72.15	135.02	**Jul-25**	3.081	3.974	81.54	119.46
Aug-24	2.855	4.144	84.38	155.11	**Aug-25**	3.106	4.012	92.50	133.17
RY1 Avg	**3.303**	**4.763**	**60.33**	**96.10**	**RY2 Avg**	**3.288**	**4.413**	**59.73**	**82.91**

Market prices in the Model are shaped hourly for electricity and daily for natural gas based on test year actuals, reflecting how these spot markets are anticipated to trade in the pro forma year. For example, if the Mid-Columbia (Mid-C) electricity price in the first hour of the test year is ninety percent of the average of all hourly prices in the first month of the test year, then the price input in the Model for that hour is equal to ninety percent of the forward price for the matching calendar month. Similar math is performed for natural gas, but because the spot market for natural gas is traded in daily blocks the shape is daily using the daily gas price test year shapes. Backup for the price calculations is included in my workpapers.[2]

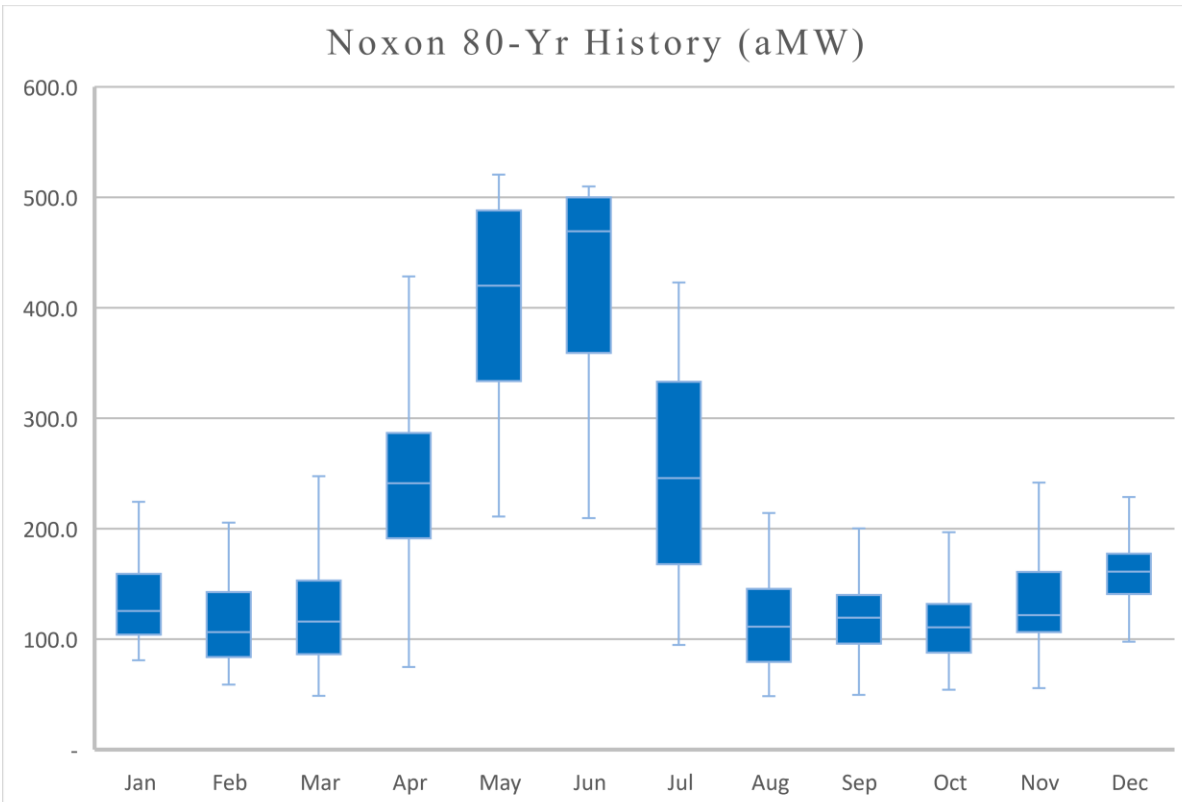
Q. How does the Company model hydro in this case?

A. A single year of median monthly values is extracted from the 80-year water record. The following box and whisker graph below depicts the monthly distribution and variability of the 80-year record and median values for our largest hydroelectric resource,

[2] See Kalich workpaper "NaturalGas_Elec_Prices_2023_1132022.xlsx".

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 presented in my workpapers.[3]

<u>Chart No. 1 – Monthly Median Water at Noxon Rapids</u>[4]



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

A. To reflect the flexibility of Company hydroelectricity resources, Avista develops individual operations logic for each river system. 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.

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[3] See Kalich workpaper "Hydro History.xlsx".

[4] White line represents the median of the monthly variation. The solid blue box depicts the 25th-75th percentile, while the horizontal lines at either ends represent the entire of variability excluding outliers.

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

A. Over the pro forma period the Model generates 66% of Clark Fork generation during on-peak hours, approximating the five-year average of on-peak generation. Since on-peak hours represent only 57% of the year, this demonstrates a substantial shift to the more valuable on-peak hours. Avista ensures this historical shaping for each river system is reflected in each month. Data supporting these calculations are in my workpapers.

Q. How are reserves modeled?

A. Due to limitations, Avista does not implicitly represent reserves in the Model. Instead, we employ two methods to reflect these obligations. As explained above, the first method is using five-year hydro shaping to reflect the operations of our hydro plants over time based on how they are impacted (de-optimized) to provide reserves. The second method is limiting the dispatch of our Northeast and Rathdrum gas plants, just as we do in actual operations. I discuss the impacts reserves place on our thermal fleet later in testimony.

Q. How is the Company valuing its firm natural gas transportation contracts in circumstances when they are not needed to fuel generation facilities?

A. When our natural gas plants consume fuel in quantities below our transportation rights, we reduce pro forma power supply costs by the surplus transportation valued at the difference in natural gas prices at the AECO and Malin hubs (i.e., we optimize the remaining transportation resource for the benefit of our customers given AECO natural gas is typically less expensive than natural gas at Malin).

III. WASHINGTON CLIMATE COMMITMENT ACT (CCA)

Q. Please describe the new Washington Climate Commitment Act (CCA).

A. During its 2021 legislative session, the Washington legislature passed, and the Governor approved, the Climate Commitment Act (CCA). The CCA is effectively a "cap-and-trade" program, with a goal to eliminate economy-wide carbon emissions by 95 percent by 2050. Its provisions start January 1, 2023. All electric utilities must secure enough allowances to cover the carbon emissions of imported power and generation from sources emitting 25,000 metric tons or more annually. Specific to Avista, the new law covers carbon emissions generated by the following:

- Washington situs-based thermal plants (except Kettle Falls Generating Station and Northeast Combustion Turbine as their annual emissions fall below the 25,000 metric ton threshold),
- Washington's multi-jurisdictional share of thermal plants located outside of Washington State,
- Carbon-emitting thermal generation imported into Washington, and
- All non-specified electricity imported into Washington.[5]

The Department of Ecology distributes no-cost carbon allowances for sources above used to serve Washington electric retail customer load. A true up is performed annually to mitigate poor hydro conditions when expected thermal plants, and/or imports, would presumably be needed to make up for the lost emissions-free hydro energy. To avoid paying twice (or double counting) for carbon emissions already regulated by Washington State's 2019

[5] The Kettle Falls biomass facility, and its small gas-fired turbine are exempt from the CCA law because their historical emissions during the 2015-2019 period fell below 25,000 tons of carbon.

Clean Energy Transformation Act (CETA)[6], allowances covering Washington retail load are distributed by the state at no cost.

Q. What do you mean by double-counting?

A. By our understanding, electric utilities were included in the CCA law to enable linkage with the California cap-and-trade law. Yet already CETA requires all generation serving Washington electric customers to be carbon neutral by 2030 and carbon free by 2045. In other words, absent CCA, Washington's retail load would be on a rapid trajectory to reduced carbon intensity and elimination. Washington customers would pay for the shift away from carbon-emitting resources. Absent no-cost allowances under CCA, Washington retail electric customers would essentially be paying for their carbon emissions reduction twice.

Q. Is the new CCA law broader than CETA?

A. The CCA is a bit broader than CETA for electric utilities in that all significant emissions in the state are to be reduced, not just those serving Washington retail electric load. The CCA also regulates the carbon emission of resources imported into Washington State, placing a cost on all emitting generation sold at the Northwest's primary, if not near-exclusive, Mid-C trading hub.

Q. Will the impacts of the CCA affect Idaho customers?

A. Yes, certain incremental costs of CCA for Idaho load should be borne by Idaho customers and are included in this case. First, Idaho load served by Washington State-sited plants emitting above the law's 25,000 metric ton annual threshold (i.e., Boulder Park) will incur a share of the costs to comply with the CCA. Second, any <u>surplus</u> thermal generation imported for sale at the Mid-C from our Lancaster, Rathdrum and Coyote Springs 2, and

[6] RCW 70A.45.020.

Colstrip, will incur a compliance cost. That surplus generation sold at the Mid-C is a benefit to our customers, albeit now facing an additional CCA compliance cost.

Q. How have CCA effects been allocated between Idaho and Washington?

A. As with other production and transmission system costs, Avista has and will allocate all these costs based on a Production/Transmission Ratio (PT Ratio) between Washington and Idaho, or approximately 65.53% to Washington and 34.47% to Idaho.

Q. How does the CCA impact power supply costs modeled in this proceeding?

A. First it is important to explain that final CCA rules were released only this past October 2022, and all regulated entities are working to comprehend its complete impacts. The regulatory entity responsible for enacting the law is the Washington State Department of Ecology (Ecology)[7]. Ecology has not yet provided detailed descriptions or examples to help entities like Avista calculate compliance costs. As a result, Avista must *approximate* power supply impacts based on its understanding of the law and associated rules which are not understood with certainty. Though uncertainty exists, the larger aspects are understood at this time.

Q. What is the expected cost of the emission allowances, and how much is included in proforma power supply expense in this case?

A. Emission allowance prices for carbon dioxide equivalents are defined by auction, with a cap and floor set by Ecology. In 2022, Ecology forecasted emission auction prices affecting the two-year rate period of this case is shown in Table No. 3:

<u>Table No. 3 – CO2 Equivalents Price per Metric Ton</u>

Year	2023	2024	2025	**Rate Year 1 Average**	**Rate Year 2 Average**
Price per metric ton CO2	$67.93	$67.68	$73.74	$67.81	$70.71

[7] WAC 173-446-010

As explained earlier in testimony, Idaho is affected by CCA as it pertains to the operations of Boulder Park, as well as outside-Washington plant output sold at the Mid-C. Modeling results in average carbon emissions of 51,306 metric tons per year over the Two-Year Rate Plan (system) for Boulder Park. Sales of imported power sold at the Mid-C from outside-Washington thermal plants generate a total of 1.04 million metric tons of carbon in Rate Year 1 (system). Rate Year 2 emissions are 1.19 million metric tons, again on a system basis. This equates on a system basis to $70.5 million and $84.1 million in rate years one and two, respectively, for CCA compliance.

Q. Does Modeling consider the cost of carbon allowances in resource dispatch?

A. Yes. Aurora dispatches thermal plants for off-system sales of power only when the value exceeds the cost of fuel, variable operation and maintenance costs <u>and projected cost of carbon allowances</u> for power generated in or otherwise imported into Washington State for sale at the Mid-C.

Q. How do you reflect carbon allowances in the Aurora modeling?

A. The allowance level is based on a forecast of actual emissions from Avista's existing system portfolio of resources under average water conditions. For each metric ton of carbon, Idaho is responsible for its PT load-ratio share, or 34.47%. CCA carbon allowance compliance is therefore modeled in Aurora such that each thermal plant must overcome in its dispatch the Idaho share of the assumed carbon allowance price, or about $23.87 per metric ton.[8] This means plants dispatch to lower customer costs only when their operating costs, <u>including</u> CCA carbon allowance costs, are below the market value of power.

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[8] $69.26/ton average price over 2 rate years * 34.47% P/T ratio (see Schedule 5) = $23.87.

Q. As they reside in the State of Washington, why are emissions from Northeast Combustion Turbine and Kettle Falls Generating Station not modeled?

A. Northeast's operating permit only allows operations for 100 hours per year. It therefore doesn't reach the compliance threshold of the CCA law (25,000 metric tons or more of annual carbon emissions). Because of this operational limit we do not expect the plant to ever exceed the threshold. Further we do not plan to operate it in the pro forma period since it provides vital contingency reserves for the system, as described later in my testimony. The Kettle Falls facility, including both the biomass and combustion turbine units, like Northeast, does not exceed the 25,000 metric ton annual threshold and therefore is exempt from CCA.

Q. You show Washington CCA compliance costs $70.5 million and $84.1 million in Rate Years One and Two, respectively. These are substantial new costs. Could these costs be lowered by not generating electricity at these plants or selling the power surplus to Idaho and Washington load at a location other than Mid-C?

A. While the cost is large, <u>it is more than recovered</u> by the revenues received from thermal dispatch (i.e., reduced market purchases and increased surplus sales). As stated earlier, resources are not dispatched unless their economics result in a favorable benefit for customers. Reducing dispatch therefore would result in higher power supply costs because the savings from reducing carbon emissions <u>would be more than offset by lost sales revenue</u>. All surplus power is priced at the Mid-C, a market we suspect already has higher prices because of the requirement that any imported power to Washington covers the cost of its emissions. Selling power outside of Washington would therefore result in lower revenues than if sold at Mid-C because it would not include the carbon allowance value in its price.

We could attempt to model a new location to sell surplus power outside of

Washington, but two critical points make doing so unrealistic. First, no liquid Northwest market exists to replace the Mid-C today. Second, any such market would have lower prices reflecting not having to pay for CCA allowances, and almost certainly would generate lower revenues approximating the lost value of CCA carbon emission allowances. The outcome on power supply modeling would therefore result in the same or higher net power supply expenses.

Q. On an overall <u>system basis</u>, what is the value of your thermal plants (net of fuel) as compared to the market?

A. In this filing the thermal fleet is estimated to generate $402 million net of fuel costs in Rate Year 1, and $346 million more in Rate Year 2,[9] for a total two-year value of $749 million. CCA compliance costs are modeled at $145 million for the two-year period, resulting in approximately $600 million net value of customers, or $300 million a year on average. The electronic version of Kalich Exhibit No. 7 includes the calculations for these amounts.[10]

Q. How does its value compare to the last general rate case before this Commission?

A. Our 2021 case did not include the impact of CCA. The value of the thermal fleet for customers in that case was approximately $101 million on a system basis, two-thirds below the average annual margin earned in this case and reflective of today's higher Mid-C market premiums caused at least in part by CCA emission compliance costs.[11] This explains

[9] See "Conf MTM" sheet in file "Confidential Exhibit No. 7 – Sch 1-5 Final.xlsx" for a tabulation of the current filing's fleet (including thermal) values.
[10] See "Conf MTM" sheet in file "Confidential Exhibit No. 7 – Sch 1-5 Final.xlsx."
[11] See workpaper "Confidential 2021 ID Kalich Exhibit No. 7, Schedule 1C with MTM.xlsx", sheet "Conf MTM."

that even while paying large CCA premiums the thermal fleet is providing much greater value for Idaho customers in this case than in the previous one.

IV. OTHER KEY MODELING ASSUMPTIONS

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

A. Yes. We make several additional assumptions affecting loads as well as forced and planned maintenance that drive our modeled pro forma costs.

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

A. Consistent with prior GRC proceedings, historical loads are weather adjusted. In this filing, test year loads ending June 30, 2022, average 1,068.4 megawatts. This compares to weather normalized proforma loads of 1,061.6 average megawatts. Table No. 4 below details data included in this proceeding. Please see Company witness Mr. Garbarino's direct testimony for additional information on the weather normalization.

Table No. 4 – Proforma Weather Normalized Loads

Month	Test Year Load (aMW)	Weather Adjustment (aMW)	Modeled Load (aMW)
Sep	921.6	5.4	926.9
Oct	944.8	4.4	949.2
Nov	1,067.9	32.7	1,100.6
Dec	1,243.9	-13.1	1,230.8
Jan	1,272.7	-3.9	1,268.8
Feb	1,187.4	-1.0	1,186.5
Mar	1,069.3	21.9	1,091.2
Apr	1,025.9	-34.2	991.7
May	928.2	-15.8	912.4
Jun	925.9	21.8	947.7
Jul	1,175.3	-89.7	1,085.6
Aug	1,055.1	-8.0	1,047.1
Total	**1,068.4**	**-6.8**	**1,061.6**

Q. What are the assumed forced outage and planned maintenance rates for the Company's thermal generation?

A. As with previous cases, the most recent five years' data is used (through 2021) to calculate average forced and planned outage rates at each plant, except for Colstrip maintenance. For Colstrip, eight years is used to reflect two, four-year maintenance cycles at the plant. We believe it is important to include two full maintenance cycles for this plant, and a single cycle was too short to cover the 5-year period used for other plants. Table No. 5 below details forced and maintenance outage rates and compares them to what currently exists in rates.

Table No. 5 – Five Year Forced and Maintenance Outage Rates, Proforma 2023 and 2021 filings

	Forced Outage Rate			Maintenance Rate		
Facility	Proforma	2021	Difference	Proforma	2021	Difference
Boulder Park	11.4%	5.8%	5.6%	4.7%	n/a	4.7%
Colstrip	7.4%	10.4%	-2.9%	7.4%	6.5%	0.9%
Coyote Springs 2	5.0%	2.8%	2.2%	16.5%	7.4%	9.1%
Kettle Falls	3.7%	2.2%	1.5%	3.1%	3.5%	-0.4%
Kettle Falls CT	6.2%	2.2%	4.0%	15.2%	13.0%	2.2%
Lancaster	1.4%	2.2%	-0.8%	5.3%	5.9%	-0.6%
Northeast	0.0%	0.9%	-0.9%	n/a	n/a	n/a
Rathdrum	1.9%	4.7%	-2.8%	4.8%	n/a	4.8%

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 Avista's contingency and other operating reserves. 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 even when operating. Northeast, even if cost-effective to run relative to market prices, is limited to 100 hours per year due to Spokane Regional Clean Air Agency regulation. As such, Northeast is assumed 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 and operating reserve requirements in April through July when the hydro system generally has limited capacity to supplement these reserves. As such, one Rathdrum unit is typically set aside during this period, even when market conditions show it to be lower cost than buying power from the market. This assumption change provides a modest benefit relative to our last general rate case where we set aside a Rathdrum unit for the entire year. Lost margins, and therefore overall power supply expenses, are lower in this filing by approximately $0.967 million relative to our last general rate case filing. Table No. 6 below details energy and lost margins resulting from modeling changes in this case.

Table No. 6 – Northeast and Rathdrum Reserves Set-Aside Lost Margins

	RY1		RY2	
	Rath	NE	Rath	NE
Total Energy Revenue	$8,063	$871	$7,164	$404
Total Fuel	($3,656)	($454)	($3,672)	($454)
Margin	$4,407	$417	$3,492	($50)
Lost Margin (2021 GRC)	$3,440			
Lost Margin Difference	$967			
MWh difference	87,883	6,228	75,624	3,114

Q. What are the contingency and other reserve requirements Avista must retain that removes these resources from dispatching when market prices would otherwise allow an opportunity to generate additional value for customers?

A. Avista's participation in the Western 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 approximately 1,100 megawatts (MW) and average pro forma load of 1,062 MW necessitate approximately 70 MW of average contingency reserves.

The amount of additional operating reserves are a bit more arbitrary than contingency reserves, as they are not defined by agreement. Yet standard industry (and prudent) practice dictates that utilities should prepare for losing their largest single generator – both with capacity and fuel. For Avista, depending on system conditions, our largest operating generator could be a smaller hydro 75 to 150 MW unit at our Clark Fork Project, or it could be one of our large natural gas plants like Coyote Springs 2, generating up to 300 MW or more.

Together, contingency and other reserves range between 74.5 and 405 MW, with an average of 325.3 MW. The combination of Northeast and a single unit at Rathdrum approximate the minimum range and well below the average. We generally supplement Northeast and Rathdrum with hydro unit capability ensuring adequate reserves are held in operations.

Q. Please describe any material changes to power contracts since the 2021 filing and the impacts on power costs.

A. Avista updates all contracts over the pro forma term to account for expiring and new contracts. Table No. 7 below lists all the long-term contracts with material changes in rate year one.[12]

[12] Please note this table is intended to illustrate changes to long-term contracts. As such, table will not tie to the total for 555 Purchase Power in Adjustment 3.00 Power Supply Adjustment.

Table No. 7 – Wholesale Contract Changes

Line No.	Contracts	2023 aMW	2021 aMW	Change
1	Chelan PUD	92.9	53.5	39.4
2	Grant PUD	38.1	38.5	(0.5)
3	Douglas Exchange	(4.6)	(2.8)	(1.8)
4	Douglas PUD	14.3	11.0	3.2
5	Columbia Basin Hydro	2.4	-	2.4
6	Lancaster			
7	Other	12.8	14.1	(1.3)
	Total Contracts	**155.8**	**114.4**	**41.4**

Our new Chelan County Public Utilities District contract, as described in detail by Company witness Mr. Kinney, meets a portion of the renewable resource need identified in Avista's 2020 Integrated Resource Plan. The contract provides an additional 5% slice of Chelan's Rocky Reach and Rock Island hydro projects starting January 1, 2024.

Our contract with Grant County Public Utilities District for an approximate three percent share of its Priest Rapids project has not changed materially from the previous rate case, but its cost is measurably higher. This contract's price is determined annually based on an auction process held annually by Grant. The auction results in a price reflecting current market prices which have increased significant in recent years. The 2021 monthly contract amounts for the period September 2021 to August 2022 are used to estimate pro forma period deliveries.[13]

Our capacity exchange with Douglas County Public Utility District expires after December 31, 2023. The parties are exploring a renewal of this contract but are far apart on price and did not reach agreement in time for inclusion in our filing. We therefore have

[13] The 2022 rates from Grant County PUD were provided to the Company after the preparation of this rate case and therefore, weren't incorporated into the modeling of this case. These updates will be incorporated when the Company updates costs prior to rates going into effect.

eliminated this contract from the pro forma after 2023. If this situation changes during the pendency of the case, Avista will update accordingly.

Besides the exchange, Avista separately contracts with Douglas for approximately 3% of its Wells Dam output. This contract includes a fixed-price capacity charge, as well as an agreed-upon energy charge, both changing annually.

A new contract with Columbia Basin Hydro Power executed in December 2022 provides new hydro capacity and energy for Avista. As a product of irrigation operations, the generation profile meets Avista's increasing summer load requirements. While only the Russell D. Smith, E.B.C. 4.6, Summer Falls Development and P.E.C 66.0 Development projects contribute during the pro forma period, the list below contains all projects.

- March 1, 2023, for the Russell D. Smith (P.E.C. 22.7) Development – 6.1 MW
- May 1, 2023, for the E.B.C. 4.6 Development – 2.2 MW
- January 1, 2025, for the Summer Falls Development – 92 MW
- March 1, 2025, for the P.E.C. 66.0 Development – 2.4 MW
- October 1, 2025, for the Quincy Chute Development – 9.4 MW
- January 1, 2027, for the Main Canal Development – 26 MW
- September 1, 2030, for the P.E.C. Headworks Development – 6 MW

The Columbia Basin Hydro (CBH) contract was evaluated as part of Avista' 2022 Request for Proposals (RFP) process. A full accounting and reporting for CBH will be sponsored in testimony in our next Idaho general rate case, once all resources procured as part of the RFP process are under contract.

There is no material change in the Lancaster contract during the pro forma period. Its increase from the 2021 case is a function of annual price appreciation agreed to in the original contract.

Q. What contracts are included in the "Other" line item in Table No. 7 above?

A. The Other category in Table No. 7 is comprised of several small PURPA contracts, as well as three larger PURPA contracts. The primary increase in the category since the 2021 case relates to renewal of three contracts: Stimson Lumber, City of Spokane Upriver Dam, and City of Spokane Waste-to-Energy Facility.

Q. Are there contracts not included in the Model?

A. Yes. The mark-to-market value of all forward natural gas and power positions with contract durations falling within the pro forma period have been included, but outside of Aurora production cost modeling.

Q. Are the Palouse and Rattlesnake Wind Farms included in the proforma?

A. No. Consistent with recent Commission orders Avista has not included these facilities in the pro forma power supply adjustment. The impacts of these resources will flow to customers as presently occurs via the PCA.

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

A. This facility serves our Washington State Solar Select program. Self-electing customers consume its entire output to serve their retail loads. In the Model we show the Adams-Neilson resource and an offsetting sale at its contract price, thereby <u>netting to its impact on power supply expense to zero</u>.

Q. How is the Company proposing that California EIM benefits be included in pro forma power expenses?

A. Avista is not including EIM benefits in the pro forma, as we began participating in the EIM only this past March 1, 2022, and increased operating experience is necessary to fairly determine an EIM value for the proforma. In our 2021 general rate case, the Parties agreed, and the Commission approved, to track EIM expenses associated, beginning at "golive" March 1, 2022, up to the benefits received. Any expenses above this amount are deferred and subject to prudency determination later. To this point expenses have not exceeded benefits for any period. The Company filed a compliance filing as required in Order No. 35606 in the 2022 PCA Annual Filing, in October 2022 that documented the calculations associated with the benefit determination. Avista proposes to continue this process until such time as enough historical information is available to make an informed decision as to alternative methods for tracking. Therefore, revenues above expenses will therefore pass through the PCA.

V. 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 Exhibit No. 7, Confidential Schedules 1 and 2. Market sales and purchases, and their revenues and costs, are determined as well and shown in Table No. 8 below, on a system basis:

Table No. 8 – System Balancing Sales & Purchases

Item	RY1	RY2	2021 GRC	RY1 Delta	RY2 Delta
	aMW	aMW	aMW	aMW	aMW
Market Purchases	11.3	6.3	13.0	(1.7)	(6.7)
Market Sales	(285.0)	(327.5)	(300.0)	15.0	(27.5)
Net	(273.6)	(321.2)	(287.0)	13.4	(34.2)
	$/MWh	$/MWh	$/MWh	$/MWh	$/MWh
Market Purchases	$48.15	$42.01	$28.12	$20.03	$13.89
Market Sales	($82.57)	($74.89)	($30.54)	($52.03)	($44.35)
Net	($77.59)	($72.69)	($28.11)	($49.48)	($44.58)
	($000)	($000)	($000)	($000)	($000)
Market Purchases	4,781	2,315	3,201	1,580	(885)
Market Sales	(206,685)	(214,869)	(80,255)	(126,430)	(134,614)
Net	(201,904)	(212,554)	(77,055)	(124,850)	(135,499)

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

VI. 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 determines revenues and expenses associated with dispatch of Company resources and contract rights, as determined by the Model's simulation for the pro forma rate period under normal weather and median hydro generation conditions. Further adjustments are made to reflect contract changes between the historical test period and the pro forma period. Table No. 9 below shows total net power supply expense during the test period and the pro forma period. For information purposes only, the power supply expense currently in base retail rates, based on a test year ending June

30, 2022 versus the pro forma period, is shown.[14]

<u>Table No. 9 – Rate Year 1 Net Power Supply Expense (System and Idaho-Share)</u>

Measure	RY1 System(1) ($000s)	Idaho Allocation(2) ($000s)
Current Authorized Power Supply Expense effective 10/1/21	$ 149,279	$ 51,456
Actual 12ME 6/30/22 Test Period Power Supply Expense	$ 181,060	$ 62,412
Proposed 2023-2024 Pro Forma Power Supply Expense	$ 179,030	$ 61,712
Proposed 2023-2024 Expense versus 12ME 6/30/22 Test Period	$ (2,030)	$ (700)
Proposed 2023-2024 Expense Change from Current Authorized	$ 29,751	$ 10,255

(1) Excludes Transmission - see Company witness Mr. Dillon and Adjustment 3.00T. Includes load and settlement adjustment.

(2) Allocated based on ROO Current Production/Transmission Ratio of 34.47%

(3) Adjusted for current weather normalized loads.

The net effect of adjustments to the test year power supply expense is a decrease in 2023-2024 of $2.030 million ($181.060 million - $179.012 million) on a system basis and a decrease of $0.70 million Idaho allocation.[15] This value is provided to Company witness Ms. Schultz for her testimony. Overall, however, <u>the increase in net power supply expense</u>, as compared to what is authorized in current base rates, is $29.751 million, or <u>$10.255 million Idaho share for Rate Year 1</u>. The increase in net power supply expense in Rate Year 2 is $13.208 million ($192.238 million - $179.030 million), or $4.553 million Idaho share, as shown in Table No. 10 below:

[14] 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.

[15] Assumes 2021 Production/Transmission (P/T) ratio of 65.53% / 34.47% for Washington / Idaho.

Table No. 10 – Rate Year 2 Net Power Supply Expense (System and Idaho-Share)

Measure	RY 2 System[1] ($000s)	Idaho Allocation [2] ($000s)
Proposed 2024-2025 Pro Forma Power Supply Expense	$ 192,238	$ 66,265
Less: Proposed 2023-2024 Pro Forma Power Supply Expense	$ 179,030	$ 61,712
Net Increase in Net Power Supply Expense	$ 13,208	$ 4,553

(1) Excludes Transmission - see Company Witness Mr. Dillon and adjustment 3.00T. Includes load and settlement adjustment.

(2) Allocated based on ROO Current Production/Transmission Ratio of 34.47%

(3) Adjusted for current weather normalized loads.

VII. PRO FORMA POWER SUPPLY ADJUSTMENT

Q. Please identify specific power supply cost items not already covered in your testimony and the total adjustments being proposed.

A. Confidential Exhibit No. 7, Schedule 2 identifies non-Model power supply expense and revenue items. These relate to power purchases and sales, fuel expenses, transmission expenses, and other miscellaneous power supply expenses and revenues.

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

A. The purpose of test period adjustments is normalization of power supply expenses for expected (i.e., average) weather and median hydroelectricity generation, to reflect current forward natural gas prices, and include other known and measurable changes for the pro forma period.

Q. Please describe each adjustment.

A. Confidential Exhibit No. 7, Schedule 3 provides a brief description of each adjustment line item of the pro forma. Detailed work papers demonstrate actual and pro forma revenues and expenses.

Q. How are long-term power contracts included in the pro forma?

A. The Model tabulates the value of all long-term physical power contracts within.

Q. How are term transactions accounted for in the pro forma?

A. The Company's Risk Management Policy, sponsored by Mr. Kinney within Exhibit No. 6, Schedule 2C, allows the Company to enter term transactions lessening power supply expense volatility. Our Risk Management Policy enables term transactions out as far as three years. The Company takes power and natural gas positions into the future, using both physical and financial arrangements, in the forward markets; many of these transactions can fall within the pro forma period.

Where some or all of a physical or financial contract term exists within the pro forma period, its costs are included in the Model.[16] Financial contracts only affect power supply expenses based on the difference between their price and the market value of power. Physical contracts also account for expected energy deliveries by increasing (for sales) or decreasing (for purchases) our net load obligations.

The Model in its current instance cannot value natural gas contracts. They are instead valued outside of the model at their delivery basin. The valuation uses the same natural gas price as used in the Model. The pro forma value of our natural gas purchases may be found in my work papers.[17]

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

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[16] Financial contracts include only costs in the Model. Physical contracts include both costs and delivered energy.
[17] See Kalich electronic workpapers, tab 'Conf Fuel Costs' of spreadsheet "Confidential Exhibit No. 7 - Schedules 1C-5.xlsx."

A. Non-gas fuel is procured for Colstrip (coal) and the Kettle Falls Generating Station (wood waste). In its fuel supply contract, the coal price for Colstrip is dependent on the volume purchased each year. Pro forma period consumption levels are used to define the contract fuel price; the calculation is provided in workpapers.[18] After the Model dispatches the plant, our coal supply contract prices are applied to that dispatch.

Hog fuel (i.e., waste wood) fuel prices at the Kettle Falls Generating Station are based on multiple contracts we have with fuel suppliers supporting our existing inventory. Its fuel price is determined in an approach like Colstrip. Expected Model dispatch is priced using budgeted prices from our fuel supply contracts. Fuel cost calculations for the Kettle Falls Generation Station are in my workpapers.[19]

Q. What changes in transmission expense are in the pro forma compared to the test-year and the expense in current base rates?

A. Firm transmission contracts are required to deliver power from generation to loads and markets, deliver power from markets to load, meet resource adequacy requirements and ensure reliability requirements for the electric system. In addition to Company-owned point to point or network transmission, the Company has long-term transmission contracts and network transmission rights primarily with Bonneville Power Administration. Bonneville Power Administration transmission costs included in the pro forma reflect current contract pricing from its general rate case TC-2021. We believe there will be no transmission price changes for years 2023 and 2024. The Company has updated the transmission pro forma expense to reflect additional transmission for our new Columbia Basin Hydro contracts. Finally, Network Transmission expense (also called "borderline wheeling") is based on a five-

[18] See worksheet "Conf Colstrip Fuel Model" in the spreadsheet version of my Exhibit No. 7.
[19] See worksheet see "Kettle and Colstrip Fuel 2017-2021.xlsx".

year use average priced at current rates.

Q. Please explain how natural gas transportation contracts are included in the pro forma.

A. The value of our firm natural gas transportation contracts from AECO to our power plants are discussed earlier in my testimony. Contracted costs for the two-year rate period are included in the pro forma.

Q. Please summarize your proposed pro forma power supply expense that is provided to Ms. Schultz for the Company's electric Pro Forma Study.

A. The net effect of my adjustments to the test year power supply expense is a decrease in 2023-24 of $2.030 million ($181.060 million - $179.030 million) on a system basis, and a $0.70 million Idaho allocation. Overall, however, the increase in net power supply expense in 2023-24, <u>as compared to what is authorized in current base rates</u>, is $10.255 million (Idaho share). The increase in net power supply expense in 2024-25 is $4.553 million (Idaho share).[20]

VIII. PCA AUTHORIZED VALUES

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

A. The proposed authorized level of annual system net power supply expense and revenues is $179.0 million for the pro forma. This is the sum of FERC Accounts 555 (Purchased Power), 557 (Other Expenses), 501 (Thermal Fuel), 547 (Fuel), 565 (Transmission of Electricity by Others, 537 (Montana Invasive Species), less Account 447 (Sale for Resale)

[20] In addition to the proposed pro forma net power supply revenue and expense amounts discussed above and included by Ms. Schultz within PF Adjustment 3.00P, PF Adjustment 3.00P also includes generation O&M expenses of $121,000 related to the Western Regional Adequacy Program ("WRAP"), as discussed and supported by Mr. Kinney.

and 456 (Other Electric Revenue). It also includes transmission revenue discussed by Company witness Mr. Dillon.

Q. What is the level of retail sales and the proposed Load Change Adjustment Rate for the PCA over the Two-Year Rate Plan?

A. The proposed authorized level of retail sales to be used in the PCA is year ending June 30, 2022 weather adjusted Idaho retail sales. The proposed Load Change Adjustment Rate, which is the energy related portion of the average production and transmission cost, is $25.23/MWh for Rate Year 1, pro forma period September 1, 2023-August 31, 2024. For Rate Year 2, the proposed Load Change Adjustment Rate is $26.54/MWh, which includes the impact of production and transmission costs for Rate Year 2 as pro formed by Ms. Schultz.

The proposed authorized PCA power supply expense and revenue, transmission expense and revenue, REC revenues, Load Change Adjustment Rate and retail sales over the Two-Year Rate Plan are shown in Exhibit No. 7, Schedule 5.

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

A. Yes, it does.