Exh. CGK-1T

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET NO. UE-20______

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 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 rate-making, 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 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 ongoing Power Supply Workshops required as part of Order No. 07 in Docket UE-170485 et. al., and how this effort has informed development of the proposed authorized level of power supply expense included in this case. I will explain efforts the Company has undertaken to simplify our power supply adjustment in order to provide for better transparency and ease discovery for the Parties, while at the same time providing a reasonable level of expense in this case. My testimony will include 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 the current level of authorized power supply expense. Finally I will identify and explain the proposed pro forma adjustments to the 2019 test period power supply revenues and expenses, including the Retail Revenue Credit used in Energy Recovery Mechanism (ERM) deferral calculations.

A table of contents for my testimony is as follows:



**Q. Are you sponsoring any exhibits in this proceeding?**

A. Yes. I am sponsoring exhibits marked Exh. CGK-2 through Exh. CGK-8 as shown in Table No. 1 below. Confidential Exh. CGK-2C and CGK-3 through Exh. CGK-6 are contained within one workbook in my workpapers, with all formulas and links intact for ease of reference. Exh. CGK-7 and Exh. CGK-8 are from the ERM Workshop process and provide additional detail into discussions and areas of agreement. Information contained in these exhibits were prepared by me or at my direction.

**Table No. 1 – List of Exhibits**

| **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 |
| Exh. CGK-7 | Strawman Power Supply Modeling Methodology |
| Exh. CGK-8 | Energy + Environmental Economics (E3) Report |

## II. POWER SUPPLY MODELING WORKSHOPS & METHODOLOGY

**Q. Order No. 07 in Docket No. UE-170485 the Commission instructed Avista and interested parties to convene a series of workshops to address concerns with the Company's power supply modeling. What is the status of this effort?**

A. The Company has held a series of workshops which began in August 2018, based on the direction of the Commission, which stated the following:

> Further, we order the Company to engage Staff, Public Counsel, ICNU, and other interested stakeholders in a discussion about how power cost modeling may be simplified and improved. While we do not think that a technical topic like power cost modeling lends itself to a formal collaborative or Commission proceeding at this time, w<u>e direct Avista to consult with its peer utilities, independent experts in the power cost modeling industry, Staff, and other parties to this case on ways in which the Company may document the functionality and rationale of its power cost modeling and make changes to eliminate its directional bias.</u> We order the Company to report back on this process and identify any resulting changes in its methodology in its next general rate case filing.[1] (emphasis added)

Given the complexities involved in developing power supply costs, several workshops were held beginning in the summer of 2018 and continue today. The Alliance of Western Energy Consumers (AWEC), the Public Counsel Unit of the Washington Attorney General's Office (PC), Washington Utilities and Transportation Commission Staff (Staff) and Avista (hereafter "the Parties") participated in the workshop process.

As of the time of this filing the Parties had convened 14 times and were close to finalizing a power supply methodology. The methodology is greatly simplified from previous cases and focuses on removing sources of potential bias–bias that some parties may believe leads to unreasonable results. The workshop process included a detailed review of Avista's

[1] Order No, 7, Dockets UE-170485 and UG-170486 (consolidated), paragraph 161

existing power supply modeling methods, sources of variability in our power supply expenses, exploration of the methods used by other utilities in their modeling, and the hiring of the consulting firm Energy + Environmental Economics (E3). E3 provided a third-party report, including their independent perspective and review of Avista's work. This report suggested alternatives to aid the Parties in reaching consensus.

**Q. Did you provide a status report per Order No. 07 to the Commission?**

A. Yes, the Company provided an update to the Commission on our progress, including a summary of findings and suggestions by E3, on June 25, 2020. This report was found to be in compliance with Commission guidance on September 2, 2020.

**Q. You mention a report provided by E3. What were the primary findings in this report?**

A. E3's report determined four major findings as summarized below:

- Avista's power cost modeling "…approach is extraordinarily complex and time-intensive" relative to its peer utilities" making it "…difficult for stakeholders to follow and undermining stakeholders' confidence in the accuracy of the process" (E3, pg. 2).

- ERM design "…provides an incentive for bias by rewarding the Company for overestimating its energy costs" (E3, pg. 3). However, as noted on page 53 of their report, they did not find any intentional bias in Avista's approach to modeling power costs.[2]

- The overall ERM process takes significant time for Avista and all stakeholders involved and "… it is not clear that this investment of time and resources yields any gains in efficiency, i.e., whether it leads to lower power costs than less costly alternatives" (E3, pg. 4).

[2] With regards to "bias," E3 at page 3 stated: "E3 is aware of the Commission's previous finding of a bias in Avista's calculations. E3 was not able, with the limited time and resources available for this review, to determine the source of the bias or even to verify whether there is, indeed, a bias." Additionally, at page 53: "…From our review, E3 has not found any evidence of intentional bias in Avista's approach to modeling power costs. …Nevertheless, E3 notes that the existence of a dead band within which Avista bears the risk of forecast errors provides an incentive for Avista to minimize the chance of a significant under-forecast of its energy costs."

- "Avista has very little control over its actual energy costs [and] it is…clear that the majority of Avista's energy cost variations are due to fluctuations in continental commodities markets, particularly natural gas prices and natural gas basis spreads which have a downstream impact on electricity market prices. It is notable that the ERM resulted in under-forecasts of Avista's energy costs during years in which natural gas prices were generally rising (2003-2009) and over-forecasts during years in which natural gas prices were generally falling (2011-2019)." (E3, page 3)

In addition, E3 provided the following suggestions in its report:

- Seek opportunities to simplify power cost modeling in a manner that reduces complexity and increases transparency while maintaining sufficient accuracy. Suggestions include the incorporation of market forwards and modeling a single or median water year instead of the full hydro record.
- Consider "… updating forward market inputs as close to the rate implementation date as possible … due to reliance on market forwards" in conjunction with the simplification of the modeling process (E3, pg. 4).
- Consider "… the merits and limitations of the current Energy Recovery Mechanism to better understand and potentially address the incentives it creates" through potential design modifications while balancing cost and efficiency gains (E3, pg. 4).

The report developed by E3 is provided as Exh. CGK-8.

**Q. Have the Parties reached agreement, and how does that agreement affect this case?**

A. No, the Parties have not settled on a final methodology; however, we have developed a draft proposal presently being finalized. The current working environment for the Parties, given COVID-19, has made meetings more difficult and the Parties cannot meet for in-person workshops. This said, good progress has been made to date. We expect the Parties to finalize their work by the end of this year and before final rates go into effect next year. As such, given the Parties appear close to finalizing a methodology, this filing adheres to the current draft methodology. Based on use of that methodology, my calculations support a $14.6 million lower power supply cost for Washington than authorized in our 2017 filing.[3] I am hopeful using the draft methodology will remove most, if not all, major areas of contention around power supply modeling in this case.

**Q. What are the major components of the draft methodology?**

A. I have included the latest draft methodology as Exh. CGK-7. It covers seven areas affecting power cost modeling, as follows:

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

**Q. Please provide a brief description of each area.**

A. The following summarizes the description of each area included in the draft methodology:

**1. Source of Market Prices.** One key area driving power cost variability is a lack of wholesale electricity and natural gas price forecasting accuracy. After reviewing various price forecasting sources, considering the recommendation of E3, and studying other utilities' power supply modeling methods, the draft methodology suggests continued use of forward prices for natural gas and electricity. While forward price projections are far from perfect, they appear from data to be the best available source of information. The draft methodology uses a three-month historical average of actual electricity and natural gas prices for the

[3] Company witness Ms. Andrews has incorporated the proposed change in power supply costs within her Electric Pro Forma Study.

forward rate period, referred to here as the "forward market." Electricity prices are represented by heavy (HLH) and light load (LLH) hours, 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.

**2. Modeling Tool.** The workshop effort did not find Aurora, the modeling tool used by Avista, as a driver of variability between rate case projections and actual costs. Consistent with previous General Rate Cases (GRCs), the draft methodology recommends use of Energy Exemplar's Aurora software to calculate the authorized power supply expense. Several utilities regulated by the WUTC, including Avista, use Aurora for a variety of modeling applications.

The Parties evaluated how Aurora was used in previous cases and identified some changes to simplify the modeling process and make it more transparent going forward. For instance, Avista will no longer run its power supply model for each of the 80 years making up the full water record. Rather, Avista resources will be dispatched against forward market prices (as described in Section 3 below) instead of having Aurora dispatch using Aurora-calculated prices. A single median water year represents Avista's hydro portfolio in this process.

**3. Pricing Methodology.** The Parties strived to reach a method simplifying how forward prices are input into Aurora. As such, the software will be used only for dispatching Avista resources and contracts against input prices. Input prices reflect the hourly electricity prices and daily natural gas prices as they can be transacted in the marketplace. This entails translating monthly forward HLH/LLH electricity prices to hourly prices, and monthly forward natural gas prices to daily prices to create a smoothed, normalized test year shape.

Prices will be created by breaking out the periods and algebraically shaping them based on actual test year prices. Weekdays are shifted as necessary to align the test and rate year. 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 will be made to remove such events, and the filing will document the approach used. The calculation will 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 will be calculated similarly using the Malin daily price shapes, as natural gas spot market trades are reported as a single price for each day.

**4. Hydro Conditions.** In the past Avista ran the entire hydro record through Aurora, averaging the results.[4] This required the model to run 80 times, creating a more time consuming and complex filing. This exercise, both time consuming and complex, was necessary because Aurora was used to determine market prices. The draft methodology recommends directly inputting forward market prices into Aurora, as recommended by E3, and dispatching Avista resources against those prices using a single median hydro year to simplify the modeling effort and increase transparency. Median water is determined using the fully hydro record for each project.

**5. AECO to Malin Transportation Contract Hedging Methodology.** 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 Kingsgate to multiple points south,

[4] In this filing, and in our previous 2017 case, an eighty-year record existed, beginning in 1929.

terminating at the Malin basin located in Oregon.[5] The draft methodology calls for Aurora to dispatch Avista's electric generation plants using a landed natural gas price based on Malin, where 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 then reduces natural gas fuel from the Aurora plant dispatch to lower AECO prices up to the contractual rights Avista holds from AECO and Kingsgate. Surplus transportation capacity not used for dispatch will be valued using the spread between AECO and Malin, consistent with overall market prices.

Avista thermal resources do not require the full contractual rights from AECO at all times. We continuously strive to be good steward of all of our resources, thereby lowering customer costs. As such, when the full capacity of these contracts is not needed for generation we capture the benefit of lower-priced AECO gas by transporting it to the higher priced Malin market. 100% of the benefit goes to lower our actual power supply expenses. To reflect this benefit in rates, past cases modeled the fuel price of each gas plant at its geographic location and separately valued the transportation contracts. While this calculation may seem straight forward, in practice it is a complex topic and extensive exploration and discussion between the Parties and review by E3 occurred during the workshop process.

**6. System Input Data.** The workshop Parties did not find system input data as a great driver of bias, complexity or variability. The draft methodology continues past practice substantially, namely using five-year averages for forced and planned maintenance outages,

[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.

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. will also utilize the five-year average when five years 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.

**7. Data Updates 60 Days Prior to Rates Going into Effect.** In reviewing past precedent, it was found that input assumption updates were completed before final rates went into effect in some cases and not in others. E3 recommended in their report that updating input assumptions would lead to better results. In recognition that the typical rate case proceedings entail an 11-month process and often several months of preparation time, there could be a delay of as much as 12 to 24 months before actual costs are incurred.

To offset the impacts of this timing delay, in cases in which a pro forma power supply adjustment has been included, certain power supply model data will be updated 60-days prior to rates going into effect should lessen variability and improve accuracy. As such, the draft methodology recommends 60-day updates to many of the data sets key to estimating power supply costs, 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 will 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, adding all incremental contracts with terms of less than one year affecting the pro forma period, and updating rate changes to any power and transmission service contracts included in the filing.[6]

## III. PORTFOLIO MODELING WITH AURORA

**Q. Does the Company's filing adhere to all areas of the draft methodology described above?**

A. Yes. The Company has implemented the entirety of the draft methodology.

**Q. What model is the Company using to dispatch its portfolio of resources and obligations?**

A. As with previous cases, the Company uses the Aurora market forecasting model ("Model") to dispatch its portfolio of resources and obligation.[7] The Model optimizes Company-owned resource and contract dispatch during each hour of pro forma year.

**Q. What experience does the Company have using Aurora?**

A. The Company purchased a license to use the Model in April 2002. Aurora has been used for numerous studies, including each of its integrated resource plans and rate filings after 2001. The tool is also used for various resource evaluations, market forecasting, and requests-for-proposal evaluations.

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

A. Departing from the past and following the draft methodology, the Company is using the Model with "input prices". Input prices provide the Model with hourly prices for

[6] If a pro forma power supply adjustment has been filed as part of a multi-year rate plan, only a single update would be required 60 days before the effective date of the first rate year, unless there are known, extraordinary power supply changes that should be incorporated during the rate plan.
[7] The Company uses Aurora version 13.5.1001 with a Windows 10 operating system.

electricity and daily prices for natural gas that reflect market conditions forecast for the rate period. Once prices are input, Avista resources and contracts are dispatched against the wholesale electric market price and 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. Once resources are dispatched and market transactions are determined, all costs are summed into my Exh. CGK-3.

**Q. More specifically how is the Model used differently with input prices in this case relative to past cases where the software was used to emulate market prices?**

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. Specifically, the setup contains 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 “large,” 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. And 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 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- 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. How are Avista's resources 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. What are the prices input into the Model?**

A. Following the draft methodology, forward electricity and natural gas prices use the three-month average (approximately 60 market settlement days) of Intercontinental Exchange (ICE) prices from May 11, 2020 through August 10, 2020, the date range up to the point where Avista began modeling its costs for this case. The table below details the prices input into the Model affecting our resources.

**<u>Table No. 2 – Monthly Forward Prices at Key Hubs</u>**

| | Price $/dth | | | |
|---|---|---|---|---|
| **Basin** | **AECO** | **Malin** | **Mid-C Off** | **Mid-C On** |
| **Oct-21** | 1.74 | 2.25 | 26.04 | 30.83 |
| **Nov-21** | 1.89 | 2.65 | 27.71 | 33.28 |
| **Dec-21** | 1.97 | 2.98 | 33.03 | 40.14 |
| **Jan-22** | 2.03 | 3.12 | 32.72 | 40.21 |
| **Feb-22** | 2.01 | 3.00 | 29.11 | 34.31 |
| **Mar-22** | 1.94 | 2.53 | 25.35 | 28.72 |
| **Apr-22** | 1.59 | 1.88 | 13.78 | 18.86 |
| **May-22** | 1.51 | 1.84 | 9.91 | 18.06 |
| **Jun-22** | 1.51 | 1.89 | 8.23 | 18.55 |
| **Jul-22** | 1.56 | 2.03 | 19.91 | 42.34 |
| **Aug-22** | 1.57 | 2.05 | 23.07 | 46.75 |
| **Sep-22** | 1.57 | 2.04 | 23.26 | 43.18 |
| **Avg** | 1.74 | 2.35 | 22.68 | 32.93 |

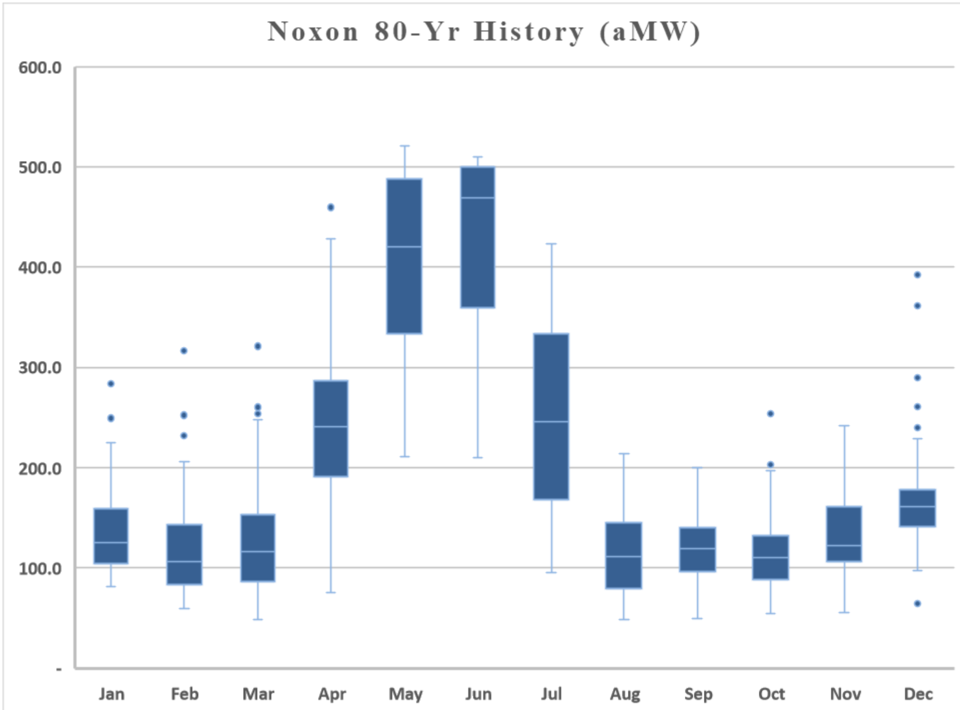
Prices are shaped hourly for electricity and daily for natural gas, reflecting how these spot markets traded in the test year and will trade in the pro forma year. The hourly (electricity) and daily (natural gas) shaping is based on 2019 test year prices. For example, if the 2019 Mid-Columbia electricity price in the first hour of October is 90 percent of the average October price in the test year, then the Mid-Columbia input price to the Model for that hour is equal to 90 percent of the October 2021 test year 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 on a daily basis using the Malin daily test year shape. Backup for the price calculations can be found in my workpapers.[8]

**Q. Has the Company made any changes to the way it models hydro for this case?**

A. Yes. In past cases all eighty years of hydro data were run through Aurora, requiring significant computing time and adding complexity. Based on the draft methodology, a single year of median monthly values extracted from the eighty-year water record is used. The graph 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 presented in my workpapers.

[8] See Kalich workpaper: NaturalGas_Elec_Prices_2020_081020.xlsx.

**<u>Chart 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 2019 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 67% 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.[9]

**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 discuss the impacts reserves place on our thermal fleet later in my testimony.

**Q. Previously you noted changes to how the Company dispatches and prices its natural gas portfolio. What is the combined impact of the changes to the usage of transportation contracts versus what was included in the current authorized level?**

A. Fuel costs are modeled to increase by $3.0 million system from the last case, due primarily to a higher utilization of our natural gas fleet. The result of these changes is a reclassification between "fuel for generation" and "natural gas off-system sales revenue". These changes were made in order to sync up with accounting records and provide additional transparency.

The $3.0 million fuel cost increase is offset in this case by a $2.2 million reduction in firm natural gas transportation costs. Lower pipeline transportation costs reflect the impacts of recent rate cases by both of our Canadian and US pipelines before their respective regulatory bodies.

---

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

**Q. How are Company natural gas-fired plants dispatched?**

A. As with previous cases, our natural gas-fired plants continue to be dispatched using fuel priced at their respective locations.

**Q. How is the pricing for natural gas-fired dispatched plants changed in the draft methodology?**

A. In past cases the Company would reflect the cost of each natural gas-fired plant using fuel priced at its delivery point. Consistent with the draft methodology, the Company is managing its AECO to Malin Transportation rights on a portfolio basis. The benefit of lower-priced AECO gas, discussed previously, is not embedded within the natural gas fuel cost recorded to FERC Account 547 in Exh. CGK-3, line 67. It is instead reflected as lower fuel expense for each plant.

**Q. How is the Company valuing the firm transportation contracts when they are not needed for fuel?**

A. In previous cases the Company calculated the value of its firm transportation from AECO to Malin based on historical values obtained from the contracts. The benefit was included as a FERC Account 456 Revenue. Following the draft methodology for this case, the benefit is reflected in lower fuel cost for our plants, reflected as a one-for-one reduction in FERC Account 456 Revenue and FERC Account 547 Other Fuel Expense. As explained earlier in my testimony, where our plants consume gas in quantities below our transportation rights, we reduce pro forma power supply costs by the surplus valued at the difference in natural gas prices between the AECO and Malin hubs.

## IV. 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 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 2019 load is 1,032.1 average megawatts compared to actual loads of 1,040.6 average megawatts. Table No. 3 below details data included in this proceeding. Please see Company witness Ms. Knox testimony Exh. TLK-1T for additional information on the weather normalization.

**Table No. 3 – Historical Loads**

| Month | Actual Load (MW) | Weather Adjustment (MW) | Modeled Load (MW) |
|---|---|---|---|
| Oct-21 | 999.3 | 0.7 | 1,000.0 |
| Nov-21 | 1,082.0 | -37.3 | 1,044.6 |
| Dec-21 | 1,136.9 | -2.8 | 1,134.0 |
| Jan-22 | 1,163.8 | 52.9 | 1,216.7 |
| Feb-22 | 1,261.7 | 16.7 | 1,278.4 |
| Mar-22 | 1,093.3 | -107.9 | 985.4 |
| Apr-22 | 929.5 | -54.2 | 875.3 |
| May-22 | 896.5 | 9.8 | 906.3 |
| Jun-22 | 949.9 | 27.8 | 977.7 |
| Jul-22 | 1,007.0 | -15.9 | 991.1 |
| Aug-22 | 1,054.1 | 40.3 | 1,094.4 |
| Sep-22 | 926.1 | -31.9 | 894.2 |
| Total | 1,040.6 | -8.5 | 1,032.1 |

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

A. Per the draft methodology, five years of data (through 2019) were used to calculate average forced and planned outage rates at each of our plants except Colstrip maintenance. The table below details these rates and compares them to our 2017 filing.

**Table No. 4 – Forced and Maintenance Outage Rates, 2020 and 2017 filings**

| | Forced Outage Rate | | | Maintenance Rate | | |
|---|---|---|---|---|---|---|
| Facility | 2020 | 2017 | Difference | 2020 | 2017 | Difference |
| Boulder Park | 5.8% | 3.6% | 2.2% | n/a | n/a | n/a |
| Colstrip | 10.4% | 11.4% | -1.1% | 4.3% | 5.9% | -1.6% |
| Coyote Springs 2 | 2.8% | 5.6% | -2.8% | 7.4% | 7.2% | 0.2% |
| Kettle Falls | 2.2% | 7.1% | -4.9% | 3.5% | 3.5% | 0.0% |
| Kettle Falls CT | 2.2% | 3.9% | -1.7% | 13.0% | 13.2% | -0.2% |
| Lancaster | 2.2% | 2.0% | 0.2% | 5.9% | 5.7% | 0.2% |
| Northeast | 0.9% | 4.3% | -3.4% | n/a | n/a | n/a |
| Rathdrum | 4.7% | 3.9% | 0.8% | n/a | n/a | n/a |

**Q. Please discuss your outage assumptions for the Colstrip units.**

A. Because the planned maintenance cycle for Colstrip is three years, consistent with the draft methodology, we use the recent six-year average (through 2019). Forced outages are consistent with other plants, using five years.

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

A. Yes. These plants provide the majority of our contingency and standby-reserve capabilities. Both are high heat rate facilities, meaning they rarely run at high levels over a year and their operating margins are low. In past cases Avista has not reflected these plants being held for reserves. Northeast, even if cost-effective to run relative to market prices, is limited to 100 hours per year due to regulation by the Spokane Air Pollution Control Board, and so the Company holds the units back for emergency and near-emergency operations. To cover unanticipated outages, our trading floor has the practice of generally setting aside one

Rathdrum unit even in the rarer hours when market conditions show it to be lower cost than buying market power. To reflect Northeast and Rathdrum operations, the Model does not dispatch the Northeast units, and is allowed to dispatch only one of the two Rathdrum units when market conditions support its operations. Table No. 5 below details energy and lost margins resulting from these modeling choices.

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

| | Rathdrum | Northeast | Other Units | Total |
|---|---|---|---|---|
| Total Energy Revenue | $ (9,763) | $ (171) | $ 19 | $ (9,915) |
| Less Fuel | $ 6,315 | $ 108 | $ 501 | $ 6,924 |
| Lost Margins | $ (3,448) | $ (62) | $ 520 | $ (2,991) |
| | | | | |
| MWh (reserve) | 252,271 | 3,086 | - | 255,357 |

**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 obligates us to carry three percent each of online generation and load as contingency reserves. Our modeled average pro forma generation of 1,275 megawatts (MW) and average pro forma load of 1,032 MW necessitate approximately 70 MW of average contingency reserves.[10]

The amount of what Avista terms standby reserves are a bit more arbitrary than contingency reserves, as they are not defined by agreement. This said, 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

[10] 1,275 MW * 0.03 + 1,032 MW * 0.03 ~ 70 MW

largest generator could be on a hydro unit at Noxon in the 100 to 150 MW range, or it could be one of our large natural gas plants like CS2 generating up to 300 MW or more.

Together the contingency and standby reserves described above range between 170 and 370 MW, and require fuel to generate electricity. The combination of Northeast and a single unit at Rathdrum is below the lower end of this range. We generally supplement the quantities with hydro unit capability.

**Q. Please describe any changes to power contracts since the 2017 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).[11] Table No. 6 below lists all contract changes in this case since our 2017 GRC.

**<u>Table No. 6 – Wholesale Contract Changes (MWa)</u>**

| Contracts | Ann | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Chelan PUD | (1.4) | 0.5 | (2.6) | (3.0) | (0.0) | 0.4 | (0.8) | (1.4) | (2.9) | (1.6) | (1.0) | (1.8) | (2.6) |
| Douglas PUD | (4.4) | (4.0) | (4.1) | (3.9) | (4.1) | (5.4) | (5.6) | (5.3) | (5.3) | (3.5) | (3.2) | (4.2) | (4.7) |
| Grant PUD | 0.6 | 3.5 | (0.2) | (1.0) | 2.2 | 2.5 | 2.6 | 2.9 | (1.4) | (1.1) | (0.6) | (1.2) | (1.1) |
| Douglas Exchange Purchase | 44.2 | 48.2 | 40.2 | 36.9 | 47.9 | 60.8 | 59.7 | 52.1 | 43.5 | 29.9 | 29.5 | 39.0 | 42.1 |
| Canadian Entitlement | (0.9) | (0.8) | (1.0) | (1.1) | (1.0) | (0.7) | (0.9) | (0.9) | (0.9) | (1.0) | (0.6) | (0.8) | (1.0) |
| Nichols Pumping | (0.8) | (4.2) | (4.2) | (4.2) | (4.2) | 2.6 | 2.6 | 2.6 | 2.6 | 2.6 | 2.6 | (4.2) | (4.2) |
| Entergy America | 40.1 | 20.0 | 20.0 | 20.0 | 20.0 | 50.0 | 50.0 | 50.0 | 50.0 | 50.0 | 50.0 | 50.0 | 50.0 |
| Palouse Wind | (3.9) | (11.5) | (0.5) | (4.7) | (1.6) | (6.9) | 1.8 | 0.6 | (0.9) | (3.7) | (0.1) | (4.0) | (14.4) |
| Rattlesnake Wind | 53.5 | 53.4 | 55.4 | 62.9 | 59.8 | 54.4 | 56.4 | 43.3 | 44.0 | 46.8 | 54.0 | 57.7 | 54.7 |
| Adams Neilson Solar | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Small Power | 0.4 | 0.5 | 0.6 | 0.7 | 1.1 | 1.1 | 0.8 | (0.2) | (0.2) | (0.0) | 0.2 | 0.1 | (0.4) |
| Spokane Waste-to-Energy | (1.0) | (1.2) | (1.1) | (0.4) | (1.8) | (2.8) | (2.4) | 1.0 | (2.0) | (1.1) | (0.4) | (2.5) | 1.6 |
| Stimson Lumber | 0.1 | (0.2) | (0.4) | (0.1) | (0.5) | 0.5 | 1.0 | 0.5 | (0.1) | 0.0 | 0.0 | 0.1 | 0.2 |
| Upriver | (0.9) | 0.3 | 0.4 | (1.8) | (1.6) | (1.3) | (2.5) | (2.6) | (0.5) | (0.6) | (0.0) | 0.5 | (0.5) |
| WNP-3 | (45.8) | (109.6) | (108.9) | (55.3) | (54.8) | - | - | - | - | - | - | (110.3) | (110.5) |
| Douglas Exchange | (47.0) | (47.0) | (47.0) | (47.0) | (47.0) | (47.0) | (47.0) | (47.0) | (47.0) | (47.0) | (47.0) | (47.0) | (47.0) |
| Douglas Settlement | (1.8) | - | - | - | - | (7.0) | (7.0) | (5.0) | (2.5) | - | - | - | - |
| **Total Contracts** | **31.0** | **(52.1)** | **(53.4)** | **(2.0)** | **14.4** | **101.3** | **108.8** | **90.6** | **76.3** | **69.7** | **83.3** | **(28.6)** | **(37.9)** |

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

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

A. Yes. First is the new Rattlesnake Wind project entering service in late 2020. The plant will serve loads for the entirety of the pro forma period. We used the vendor forecast because of the lack of actual operating history, totaling 468,934 MWh annually. Unlike where owned by Avista, the power purchase agreement for Rattlesnake Wind provides that we pay for power only when it is generated; therefore, the risk of underperformance is borne by the project owner and not Avista.

A second change worth noting is the 2019 expiration of our BPA contract for WNP-3 replacement power. We also have entered into a new contract with Douglas County PUD. This sale through is paired with an increase in our Douglas Mid-C contract (Douglas Exchange Purchase). Finally, we have entered into or renewed a number of small PURPA contracts reflected in the Small Power line of the table above. Each new contract is included in my working papers.

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

A. Yes. We don't model index contracts because they have no impact on power supply costs. There is only one such contract in this year's filing, the 2021 Morgan Stanley REC sale. This contract prices all delivered energy at the Mid-C index. Besides having no impact on power supply expense because it is index-based, the Morgan Stanley contract has flexible REC deliveries with the potential for all deliveries to occur prior to the start of the 2021 pro forma year. REC values associated with this contract also are not accounted for in pro forma power supply costs, but rather are reviewed annually as part of the REC filing.

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

A. This facility is used in its entirety to serve our Solar Select program whereby self-electing customers use its energy to serve their loads. In the Model we show the Adams-Neilson resource and an offsetting sale at its contract price, thereby removing ensuring the resource does not impact our 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. Why is the Energy America contract not included in this case?**

A. The Energy America contract for energy and associated RECs has expired. In its place are sales made into the California marketplace reflected in the pro forma as "CAISO Market Sales." These sale quantities are not represented in the Model because there is no contract obligation to deliver them. Instead we pro forma in an amount equal to the 3-year average of sales to CAISO since the Energy America contract expired.

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

A. Non-gas fuel is procured for Colstrip coal 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. Unit wood fuel costs at Kettle Falls are based on multiple shorter-term contracts with fuel suppliers and inventory. The total fuel cost is determined similarly to Colstrip; expected Model dispatch is priced using the budgeted prices from our fuel supply contracts. Fuel cost calculations can be found in my workpapers.

## 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 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.

**Table No. 7 – System Balancing Sales & Purchases**

| System Balancing Sales & Purchases – 2020 GRC vs. 2017 GRC | | | |
|---|---|---|---|
| | | | |
| **Item** | **2020 GRC** | **2017 GRC** | **Delta** |
| | **aMW** | **aMW** | **aMW** |
| Market Purchases | 11.5 | 37.8 | (26.3) |
| Market Sales | (317.5) | (187.5) | (130.0) |
| *Net* | (306.0) | (149.6) | (156.4) |
| | | | |
| | **$/MWh** | **$/MWh** | **$/MWh** |
| Market Purchases | 28.35 | $22.63 | $5.72 |
| Market Sales | 27.62 | $24.42 | $3.20 |
| *Net* | 27.6 | $24.87 | $2.73 |
| | | | |
| | **($000)** | **($000)** | **($000)** |
| Market Purchases | 2,853 | 7,502 | (4,649) |
| Market Sales | (76,835) | (40,099) | (36,736) |
| *Net* | (73,982) | (32,597) | (41,385) |

The 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 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 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 period and the pro forma period.

**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 term power purchases and sales, 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 accompany filing and support 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. The pro forma includes actual term transactions affecting the pro forma period. These transactions include fixed-price physical and financial electricity and natural gas transactions. The Model is used to value all physical and financial electricity transactions 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. What changes in transmission expense are in the pro forma compared to the test-year and current rates?**

A. Since our last case Avista executed a 50 MW point-to-point contract with BPA enabling delivery of a larger share of its Coyote Springs 2 generating capacity on a firm basis. This cost is included in our pro forma power supply expense and represents the vast majority of the transmission cost increase since our 2017 filing.

**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.[12]

[12] 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.

**<u>Table No. 8: Pro Forma Power Supply Adjustment Summary</u>**

| Measure | System[(1)] | Washington Allocation[(2)] |
|---|---|---|
| | ($000s) | ($000s) |
| Current Authorized Power Supply Expense [(3)] | $171,545 | $ 111,742 |
| Actual 2019 Test Period Power Supply Expense | $165,617 | $ 108,711 |
| Proposed 2021-2022 Pro Forma Power Supply Expense | $148,017 | $ 97,158 |
| Proposed 2021-2022 Expense versus 2019 Test Period | $ (17,600) | $ (11,553) |
| Proposed 2021-2022 Expense versus Current Rates | $ (23,528) | $ (14,584) |

(1) Excludes Transmission - see Company Witness Schlect and adjustment 3.00T.
(2) Allocated based on ROO Current Production/Transmission Ratio of 65.64.
(3) Adjusted for current weather normalized loads

The net effect of my adjustments <u>versus the test year power supply expense</u> is a *decrease* of $17.6 million on a system basis, or $11.6 million for Washington. The net effect of my adjustments <u>versus current authorized power supply expense</u> is a *decrease* of $23.5 million on a system basis, or $14.6 million for Washington. On a revenue requirement basis, the Company's overall request compared to current authorized, is lower by $15.3 million as shown in Ms. Andrews' Pro Forma Power Supply Adjustment (3.00P).[13]

## <u>VII. ERM AUTHORIZED VALUES</u>

**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 supply expense is $97.158 million (Washington-basis) for the pro forma period, <u>excluding</u> transmission revenues (sponsored by Mr. Schlect). This is the sum of Accounts

[13] See Exh. EMA-2, p.8

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 2019 weather-adjusted Washington retail sales. The proposed Retail Revenue Adjustment rate is $15.37/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. Please summarize your proposal for updating power supply costs prior to final rates becoming effective?**

A. As discussed earlier, Avista adopts the draft methodology which recommends updates to many of the data sets key to estimating power supply costs 60 days prior to rates going into effect, 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

**Q. Throughout your testimony you refer to the Power Supply Workshops and the substantial progress made to date by the Parties. When do you expect the completion of these workshops?**

A. As noted above, with regards to the Power Supply Workshops good progress has been made to date. Avista expects the Parties will finalize the work completed in these workshops by the end of this year and before final rates go into effect October 1, 2021.

**Q. Since the Power Supply Workshops have not reached conclusion, do you intend to incorporate any agreed upon modifications by the Parties in this proceeding, and if so, how?**

A. Yes, any further changes, if any, agreed to by the Parties during the remainder of the workshops, would be incorporated into the power supply adjustment to be rerun 60 days prior to the effective date of this case.

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

A. Yes, it does.