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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF AVISTA CORPORATION FOR THE AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC SERVICE TO ELECTRIC CUSTOMERS IN THE STATE OF IDAHO	)))))))	CASE NO. AVU-E-19-04 DIRECT TESTIMONY OF CLINT G. KALICH

FOR AVISTA CORPORATION

(ELECTRIC)

I. INTRODUCTION

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

A. My name is Clint 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 joined Economic and Engineering Services, Inc. (now EES Consulting, Inc.), a northwest management-consulting firm located in Bellevue, Washington. EES Consulting worked primarily for municipalities, public utility districts, and cooperatives in the area of electricity, water and wastewater 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 EES Consulting 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 now 28-year utility 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: 1) describe the Company's use of the AURORA dispatch model, or "Dispatch Model;" 2) discuss our transmission revenue assumptions; 3) identify and explain the proposed normalizing and pro forma adjustments to the 2018 test period power supply revenues and expenses; and 4) detail the proposed level of expense and Load Change Adjustment Rate (LCAR) for Power Cost Adjustment (PCA) purposes, using the pro forma costs proposed by the Company in this filing.

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 Exhibit No. 7, Schedules 1 - 6. Schedule 2C is a confidential exhibit and marked as such. Table No. 1 below shows the Schedule list for Exhibit No. 7.

Table No. 1 - Exhibit No. 7, Schedule List:

Schedule Name	Brief Description
Schedule 1	AURORA Modeling Changes Summary
Confidential Schedule 2C	Monthly Dispatch Model Results - Generation Resources
Schedule 3	Power Supply Pro Forma - Idaho Jurisdiction
Schedule 4	Brief Description of Power Supply Adjustments
Schedule 5	Market Purchases and Sales, Plant Generation and Fuel Cost Summary
Schedule 6	ERM Authorized Expense and Retail Sales

All information contained in Exhibit No. 7 was prepared by me or under my direction.

II. THE DISPATCH MODEL

Q. What testimony will you cover in this section?

A. This portion of my testimony explains the key assumptions driving the Dispatch Model's market forecast of electricity prices. The discussion includes the variables of natural gas, loads and resources, and hydroelectric conditions. I will describe how the model dispatches Company resources and contractual rights to maximize customer benefit; it tracks their values for use later in my pro forma calculations.

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

A. The Company uses Energy Exemplar, Inc.'s AURORA market forecasting model ("Dispatch Model") and its associated database for determining power supply costs.[1] [/2] The Dispatch Model optimizes Company-owned resource and contract dispatch during each hour of the January 1, 2020 through December 31, 2020 pro forma year.

Q. Please briefly describe the Dispatch Model.

A. The Dispatch Model is a fundamentals-based tool containing demand and resource data for the entire Western Interconnect. It employs multi-area, transmission-constrained dispatch logic to simulate wholesale power market conditions. Its dispatch captures the dynamics, and economics, of electricity markets—both short-term (hourly, daily, monthly) and long-term. On an hourly basis the Dispatch Model develops an available resource stack, sorting resources from lowest to highest cost. It then compares this resource stack with load obligations in the same hour to arrive at the least-cost market-clearing price for the hour. Once resources are dispatched and market prices are determined, the Dispatch Model singles out Avista resources, contracts and loads and values them against the marketplace.

Q. What experience does the Company have using AURORA?

A. The Company purchased a license to use the Dispatch 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 also is used for various resource evaluations, market forecasting, and requests-for-proposal evaluations.

Q. Who else uses AURORA?

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[1] The Company uses AURORA version v13.2 and Aurora's base dataset U.S. - Canada 2018_v3 on a computer running the Windows 7 operating system.

[2] Energy Exemplar purchased EPIS in late 2017.

A. AURORA is used all across North America, Europe, Asia, and the Middle East. In the Northwest specifically, AURORA is used by Idaho Power, the Bonneville Power Administration, the Northwest Power and Conservation Council, Puget Sound Energy, , Portland General Electric, PacifiCorp, Seattle City Light, Grant County PUD, and Snohomish County PUD.

Q. What benefits does the Dispatch Model offer for this type of analysis?

A. The Dispatch Model generates hourly electricity prices across the Western Interconnect, accounting for its specific mix of resources and loads. The Dispatch Model reflects the impact of regions outside the Northwest on Northwest market prices, limited by known transfer (transmission) capabilities. It emulates emissions markets and, where configured correctly with data, is able to address oversupply (i.e., negative price) conditions. With AURORA the Company can generate price forecasts in-house instead of relying on exogenous forecasts.

Q. Why is a tool like the Dispatch Model important for setting rates?

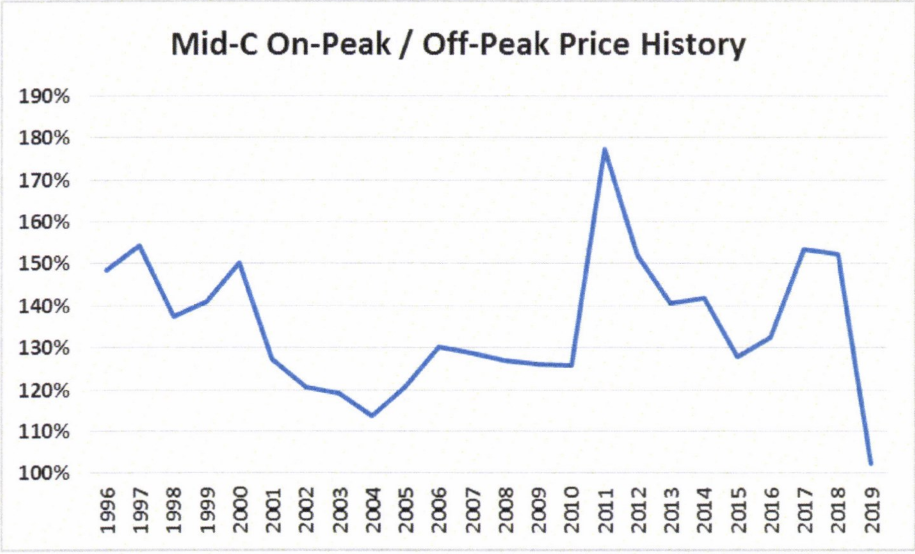
A. The Company owns a number of resources, including hydroelectric plants and natural gas-fired peaking units serving customer loads. These plants provide their greatest value during on-peak hours and when regional loads, and prices in the marketplace, are highest. Further, these plants should be operated only when their costs are lower than the cost of surplus power from other participants in the marketplace. By optimizing resource operation on an hourly basis, the Dispatch Model is able to appropriately value the capabilities of these assets and purchase lower-cost surplus power when it lowers rates.

Q. How can the Commission ensure the model is appropriately reflecting the value of these resources?

A. By reflecting market fundamentals, Company resources and contracts are valued appropriately. One measure is the relationship between peak- and off-peak prices. Because on-peak prices are higher than off-peak prices, contracts and resources with optionality (e.g., hydro with storage) should dispatch with more power generated in the on-peak hours. The value of generating resources should be higher in on-peak periods relative to off-peak periods.

Forward prices for the pro forma 2020 period are 51 percent higher in the on-peak hours than off-peak hours at the time this case was prepared. The Dispatch Model forecasts on-peak prices for the pro forma period to average 29 percent higher than off-peak prices, which is within the range of history (see Illustration No. 1).

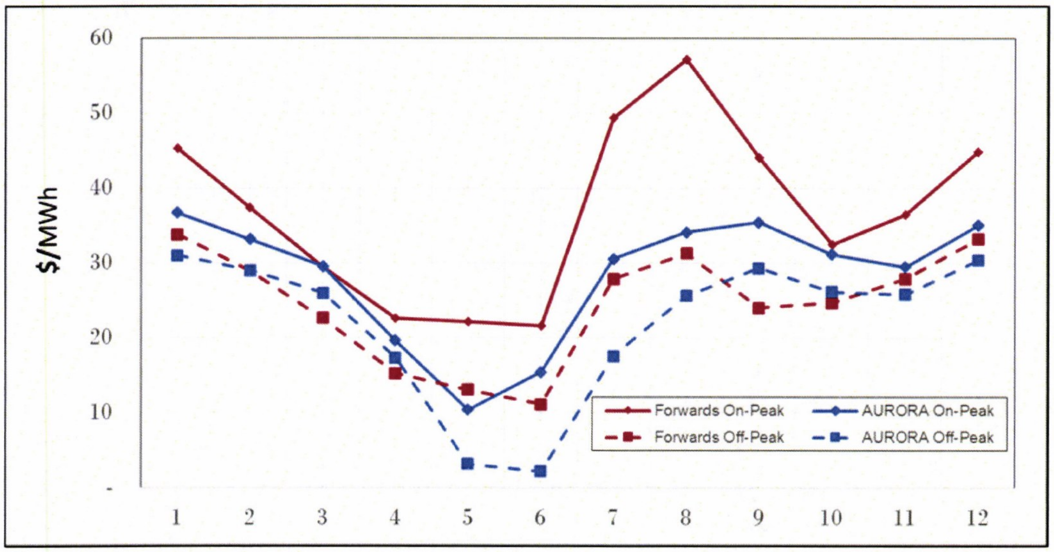
Illustration No. 1 – Historical Mid-C On-Peak / Off-Price Ratios, 1996-2019[3]



[3] 2016 is May through December average, 2019 is January through May 16 average.

A graphical representation of the differences in peak- and off-peak prices over the pro forma period is shown below in Illustration No. 2.

Illustration No. 2 – Monthly AURORA modeled versus forward Mid-C Prices



Forward Mid-Columbia prices shown are the latest one month average (March 18, 2019 through April 16, 2019) of Intercontinental Exchange (ICE) quarterly prices at the time of study preparation.

Dispatch Model and forward prices can and will be different, as forward prices are based on market expectations whereas the data used in the Dispatch Model are normalized for hydro, loads, and resource outages. Referring back to Illustration No. 1, the average price for the 2020 forward period is $36.93 per MWh; the Dispatch Model price is $28.39 per MWh. This result explains that the market is expecting an upward bias in future conditions (e.g., regional capacity deficits, low water year).

Q. On a broader scale, what calculations are being performed by the Dispatch Model?

A. The Dispatch Model's goal is to minimize overall system operating costs across the Western Interconnect, including Avista's portfolio of loads and power supply options. The Dispatch Model generates a wholesale electricity price forecast by evaluating all Western Interconnect resources simultaneously in a least-cost equation to meet regional loads. As the Dispatch Model progresses from hour to hour, it "operates" those least-cost resources necessary to meet load. With respect to the Company's portfolio, the Dispatch Model tracks the hourly output and fuel costs associated with Avista's portfolio generation. It also calculates hourly energy quantities and values for the Company's contractual rights and obligations. In every hour, the Company's loads and obligations are compared to available resources to determine a net position. This net position is balanced using the simulated wholesale electricity market. The cost of energy purchased from or sold into the market is determined based on the electric market-clearing price for the specified hour and the amount of energy necessary to balance loads and resources.

Q. How does the Dispatch Model determine electricity market prices, and how are the prices used to calculate market purchases and sales?

A. The Dispatch Model calculates electricity prices for the entire Western Interconnect, separated into various geographical areas such as the Northwest and Northern and Southern California. The load in each area is compared to available resources and costs, including resources available from other areas that are linked by transmission connections, to determine the electricity price in each hour. Resource costs include operation and maintenance, fuel, local, state and federal tax charges and credits, and, where applicable, emissions fees.

Ultimately, the market price for an hour is set based on the costs of the last resource in the dispatch stack. This resource is referred to as the "marginal resource." Given the prominence of natural gas-fired resources on the margin, this fuel is a key variable in determining wholesale electricity prices.

Q. How does the Dispatch Model operate regional hydroelectric projects?

A. The model begins by "peak shaving" loads using hydro resources with storage. When peak shaving, the Dispatch Model determines the hours with the highest loads and allocates to them as much hydroelectric energy within the constraints of the hydro system. Remaining loads are then met with other available resources.

Q. Has the Company made any modifications to the AURORA database for this case?

A. Yes. Parting modestly from the past, Avista has for this case attempted to rely more heavily on the default Aurora database. We do modify natural gas prices to match the latest one month average of forward prices over the pro forma period and we continue, as in the past, by including regional Bonneville Power Administration hydro study data to enable modeling of the hydrologic record. We also make changes unique to our portfolio, including gas plant heat rates and O&M costs.

Q. Does the Company have a more detailed list of changes made to the AURORA database?

A. Yes. Exhibit No. 7, Schedule 1 provides a list of changes made to the AURORA database, including a short explanation of the rationale for each. These changes can be audited by exploring my work papers, as well as by evaluating change set and table data contained in the AURORA files provided with my testimony.

Q. Has the Company made any methodological changes to the way it models hydro in this case compared to prior cases?

A. No. The monthly split between on- and off-peak generation remains based on the most recent five-year (2014-2018) average. This approach ensures customers benefit from the capability of these resources to shape water fuel to the highest-value hours.

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

A. Over the pro forma period, the Dispatch Model generates 67 percent of Clark Fork hydro generation during on-peak hours (based on average water). Since on-peak hours represent only 57 percent of the year, this demonstrates a substantial shift of hydro resources to the more expensive on-peak hours. This is identical to the five-year historical (actual) average of on-peak hydroelectric generation at the Clark Fork through December 2018. Similar relative performance is achieved for the Spokane and Mid-Columbia projects.

III. OTHER KEY DISPATCH MODELING ASSUMPTIONS

Q. Exhibit No. 7, Schedule 1 provides a list of assumptions made in the Dispatch Model. Are there any Dispatch Modeling assumption you wish to highlight here?

A. Yes. Above I explained that natural gas prices greatly affect power supply costs. Pro forma loads also are a large driver since they define how much generation we must serve. Finally, Colstrip outage assumptions are greatly material because of the plant's low-cost contribution to our portfolio.

Q. Please describe your update to pro forma period natural gas prices.

A. Consistent with past general rate case filings, natural gas prices are based on a one-month average of forward prices; in this case from March 15, 2019 through April 15, 2019 for calendar-year 2020 monthly forward prices. Natural gas prices used in the Dispatch Model are presented below in Table No 2.

Table No. 2 – Pro Forma Natural Gas Prices

Basin	Price ($2020/dth)	Basin	Price ($2020/dth)
AECO	$1.222	Stanfield	$2.325
Malin	$2.405	Kingsgate	$2.180

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

A. Again consistent with prior general rate case proceedings, historical Company loads are weather-adjusted. For this filing, weather normalized 2020 load is 1,040.0 average megawatts (aMW) compared to actual loads of 1034.3 (aMW). Table No. 3 below details data included in this proceeding. Further information on the weather normalization is within Company witness Ms. Knox's testimony.

Table No. 3 – Pro Forma Loads (aMW)

Month	Actual Load	Weather Adjustment	Modeled Load		Month	Actual Load	Weather Adjustment	Modeled Load
Jan-20	1,144.7	47.5	1,192.1		Jul-20	1,063.7	-49.6	1,014.1
Feb-20	1,167.3	-18.8	1,148.5		Aug-20	1,073.2	-20.3	1,052.9
Mar-20	1,063.8	-3.6	1,060.2		Sep-20	914.1	17.9	932.1
Apr-20	976.7	-1.0	975.8		Oct-20	943.9	3.5	947.4
May-20	921.1	24.6	945.6		Nov-20	1,062.6	6.6	1,069.2
Jun-20	929.4	22.2	951.6		Dec-20	1,155.5	38.3	1,193.8

Q. Please discuss outage assumptions for your thermal plants.

A. Consistent with prior cases, Avista uses the most recent available five-year (2014-2018) average forced outage rate to estimate long-run performance at our non-peaking thermal plants. Maintenance outages also affect plant availability. As with forced outages, maintenance outage rates for our non-peaking plants are based on a five-year average, except for Colstrip. The Colstrip maintenance outage rate is based on the most recent six-years. Six years are used because routine plant maintenance outages occur once every three years. Absent including an additional year for averaging, the assumption would not reflect the full maintenance cycle for the plant.

Peaking plants run rarely and therefore forced outage and maintenance outages have small effects on power supply expenses. For the Rathdrum, Northeast and Kettle Falls combustion turbines the pro forma assumes no derating for maintenance outages and a five percent forced outage rate. Boulder Park similarly has no derating for maintenance, but its forced outage rate is estimated at 15 percent.

Q. Are there any other significant Dispatch Modeling changes from the last rate filing?

A. No.

<u>IV. RESULTS OF THE DISPATCH MODEL</u>

Q. Please summarize the results from the Dispatch Model.

A. The Dispatch Model tracks the Company's portfolio during each hour of the pro forma study. Generation for each resource are summarized by month. Total market sales and purchases are also determined and summarized by month. These values are contained in Exhibit No. 7, Confidential Schedule 2C. Resource and contract revenues and expenses not accounted for in the Dispatch Model (e.g., contract fixed costs) are added to the results of Exhibit No. 7, Schedule 3 to determine net power supply expense.

<u>V. NON-DISPATCH MODEL ASSUMPTIONS</u>

Q. Are there changes outside of the AURORA Dispatch Model included in this case?

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. This case also includes the costs and benefits of our Palouse Wind and Rattlesnake Flat wind power purchase agreements (PPAs). The Rattlesnake Flat PPA was recently executed, and begins commercial operation in late 2020. It is modeled in this case as entering service in December of 2020. Company witness Mr. Kinney's direct testimony and exhibits provide support for the Rattlesnake Wind PPA (see Kinney Direct and Exhibit No. 5, Confidential Schedules 3C – 5C).

Palouse Wind PPA, however, is an existing wind project. The 30-year Palouse Wind PPA was executed in 2011 by the Company and purchases all of its output (105

MW nameplate capacity) and environmental attributes. The project began commercial operation in December 2012. Per GRC settlements since 2012, the Company recovers Palouse Wind PPA costs through the PCA. In this case the Company is requesting all Palouse Wind PPA costs be included in base rates, and base power supply net costs, beginning January 1, 2020.

Q. In prior Avista GRCs did the Commission preclude the Company from requesting that the full cost of the Palouse Wind PPA be included in base retail rates in the future?

A. No. In prior GRCs where Avista sought recovery of the Palouse Wind PPA, the parties agreed for settlement purposes to track Palouse Wind project through the PCA. The Commission has not otherwise precluded Avista from seeking to incorporate the Palouse Wind PPA into base rates, like all of its other generating resources.

Q. For the past several years, with Palouse Wind tracked through the PCA, how much has the Company's Shareholders absorbed of the annual PPA costs (10%), thus benefiting Idaho customers.

A. Through December 2019 the Company will have absorbed approximately \$2.1 million since December 2012[4]. This has been a direct benefit to customers of unrecovered PPA costs absorbed by the Company through the PCA mechanism. The Company believes it is time for recovery of this project within base rates.

Q. Was Palouse Wind a prudent resource acquisition?

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[4] This value was calculated by taking the difference between the cost of the Palouse Wind PPA and the cost of wholesale energy (which would have been purchased absent the PPA in order to serve customer needs), multiplied by 10 percent (Avista's share of the PCA sharing mechanism).

A. Yes. At the time the contract execution, the Palouse Wind purchase was one of, if not the lowest priced, wind resource projects in the Northwest. The purchase price also compared favorably to the Idaho avoided cost rates at the time. The 20-year (2013-2032) levelized cost of Palouse Wind was $63.61/MWh. By comparison, Avista's Idaho avoided cost rate (effective 8/30/2011), including the wind integration deduction, for the same period was $67.41/MWh. The Palouse Wind contract was a cost-effective, prudent, and long term resource acquisition. It was and remains a prudent acquisition, whose costs should be borne by ratepayers.

Q. Do Idaho customers receive benefits other than an energy resource from Palouse Wind and other Avista renewable energy resources?

A. Yes. Avista is actively involved in the Renewable Energy Credit (REC) market and has received significant REC sales revenue due to our mix of renewable resources. While the state of Idaho may not have a renewable portfolio standard (RPS), the presence of RPSs in other western states and the national Green-e REC market has provided significant benefits to Idaho customers. Avista's Idaho customers have received $22.8 million dollars of revenue from REC sales for the period 2007 through 2018. This rate case includes $423,300 of REC sales revenue for Idaho customers.

VI. ELECTRIC TRANSMISSION ASSUMPTIONS

Q. Is the Company proposing any adjustments to Transmission FERC account 456 in this case?

A. No. Actuals are adjusted to the 2017 general rate case authorized level of \$15.15 million system. This is \$2.77 million reduction from 2018 actual transmission revenues of \$17.92 million.

Q. Why did the Company reduce 2018 actual transmission revenues for this filing?

A. Higher 2018 transmission revenues reflect a one-off windfall due to the Embridge natural gas pipeline failure. This unfortunate regional event created significant short-term demand for Avista transmission, as west-side loads were served by 3rd parties moving power plant output from the east to the west of our system to replace their natural gas-starved plants. This event is not expected to occur again. The current authorized transmission revenues, therefore, reflect transmission revenue expected during calendar year 2020.

VII. 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 AURORA model simulation for the pro forma rate period under normal weather and hydro generation conditions. Further adjustments are made to reflect contract changes between the historical test period and the pro forma period. Table No. 4 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 calendar 2017 pro forma period, is shown.[5]

Table No. 4 – Net Power Supply Expense

Measure	System	Idaho Allocation
	($000s)	($000s)
Power Supply Expense in Current Rates (2018 Pro Forma)	$ 161,230	$ 55,802
Actual 2018 Test Period Power Supply Expense	$ 135,730	$ 46,976
Proposed 2020 Pro Forma Power Supply Expense	$ 152,150	$ 52,659
Proposed 2020 Expense versus 2018 Test Period	$ 16,420	$ 5,683
Proposed 2020 Expense versus Current Rates	$ (9,080)	$ (3,143)

The net effect of my adjustments to the test year power supply expense is an increase in 2020 of $16.420 million ($152.15 - $135.73) on a system basis and a $5.683 million Idaho allocation.[6] This value is provided to Company witness Ms. Andrews for her testimony. Overall, however, the decrease in net power supply expense in 2020, as compared to what is authorized in current base rates, is $9.080 million, or $3.143 million Idaho share.

VIII. PRO FORMA POWER SUPPLY ADJUSTMENTS

Q. Please identify specific power supply cost items covered in your testimony and the total adjustment being proposed.

[5] 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.
[6] Assumes 2020 Production/Transmission (P/T) ratio of 65.39% / 34.61% for Washington / Idaho.

A. Exhibit No. 7, Schedule 3 identifies non-Dispatch 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 (average) weather and 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.

Q. Exhibit No. 7, Schedule 4 provides a brief description of each adjustment. Detailed work papers demonstrate actual and pro forma revenues.

Long-Term Contracts

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

A. In the past the Company included contract power rights and obligations in the Dispatch Model, but separately calculated pro forma revenues and expenses outside of the model. In this filing the Dispatch Model tabulates these items.

Q. Are there any new long-term power purchases or sales in the pro forma that are not in current base rates?

A. Yes. As detailed above, the Palouse Wind and Rattlesnake Flat wind projects are included in this case but are not in current base rates.

Q. Are there any long-term power purchases or sales in current base rates that are not in this pro forma?

A. Yes. The WNP-3 contract expired on April 30, 2019 and is not included in this filing.[7]

Term Transactions

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

A. The Company's risk management policy, sponsored by Mr. Kinney, executes term transactions to lessen power supply expense volatility. Our risk management policy enables term transactions out as far as three years. We take 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 a portion or all of a contract for electricity falls within the pro forma period, its costs are included in the Dispatch Model.[8] For physical electricity contracts falling within the proforma period, the Dispatch Model also accounts for expected energy deliveries by increasing (for sales) or decreasing (for purchases) our net load obligations.[9]

The Dispatch Model cannot value natural gas contracts. Natural gas is therefore valued outside of the model at their delivery basin. The valuation uses the same natural gas price as used in the Dispatch Model. The pro forma value of our natural gas purchases may be found in my work papers.[10]

Short-Term Power Purchases and Sales

Q. How are short-term transactions included in the pro forma?

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[7] The WNP-3 contract was power purchased from BPA that was priced at the O&M expense of four surrogate nuclear plants, and was originated from the settlement agreement for the never completed nuclear plant that the then Washington Water Power had agreed to buy a small portion of.

[8] Financial contracts include only costs in the Dispatch Model. Physical contracts include both costs and delivered energy.

[9] Net loads include retail load plus any obligations (up or down) to reflect contracts with 3rd parties resulting from these term transactions.

[10] See Kalich workpapers, Tab 11 of spreadsheet "Exhibit No. 7 - Schedules 1-6.xlsx."

A. Short-term electric power prices, purchases and sales are an output of the AURORA model. The Dispatch Model calculates both the volumes and costs of short-term purchases and sales that balance the system's generation and long-term purchases with retail load and other obligations.

Thermal Fuel Expense

Q. How are thermal fuel expenses determined in the pro forma?

A. The Company incurs thermal fuel expenses for its Colstrip (coal), Kettle Falls (wood-waste), and its gas-fired power plants Coyote Springs 2, Lancaster, Rathdrum, Northeast, Boulder Park, and Kettle Falls CT. Unit coal costs are based on long-term coal supply and transportation agreements for Colstrip. Unit wood waste fuel costs are based on multiple shorter-term contracts with fuel suppliers and our existing inventory. Plant-level fuel cost are the product of unit fuel cost and the generation level determined by the Dispatch Model. Exhibit No. 7, Schedule 5 details generation and fuel consumption and costs for the Company's thermal plants.

Transmission Expenses

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

A. We no longer include costs associated with transmission of our WNP-3 contract with BPA. The contract expires in June 2019. While power deliveries ended in April 2019, the transmission contract went for an additional two months.

Natural Gas Transportation

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

A. Natural gas transportation contract costs are included based on 2018 actual expense. Benefits are less certain because the value of these contracts is dependent on the basis spread between Canadian and U.S. delivery points. To estimate the value, the pro forma contains the five-year (2014-2018) average of our actual experience optimizing these contracts, or $11.25 million system.

Summary

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

A. The net effect of my adjustments to the test year power supply expense is an increase in 2020 of $16.4 million ($152.15 - $135.73) on a system basis and a $5.683 million Idaho allocation. Overall, however, the decrease in net power supply expense in 2020, as compared to what is authorized in current base rates, is $3.143 million (Idaho share).

IX. 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 $136.7 million for the pro forma. This is the sum of FERC Accounts 555 (Purchased Power), 501 (Thermal Fuel), 547 (Fuel), less Account 447 (Sale for Resale). It also includes transmission expense and transmission revenue. The proposed level of net Renewable Energy Credits (REC) and natural gas liquids revenue is also included in the total authorized net expense.

Q. What is the level of retail sales and the proposed Load Change Adjustment Rate for the PCA?

A. The proposed authorized level of retail sales to be used in the PCA is 2018 weather adjusted Idaho retail sales. The proposed Load Change Adjustment Rate is $23.41/MWh for the pro forma period, which is the energy related portion of the average production and transmission cost.

The proposed authorized PCA power supply expense and revenue, transmission expense and revenue, REC revenues, Load Change Adjustment Rate and retail sales are shown in Exhibit No. 7, Schedule 6.

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

A. Yes, it does.