Exh. CGK-3T

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET NO. UE-170485

SUPPLEMENTAL 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 Kalich. I am employed by Avista Corporation at 1411 East Mission Avenue, Spokane, Washington.

Q. Are you the same Clint Kalich that provided direct testimony in this case?

A. Yes.

Q. Why are you providing Supplemental Direct Testimony in this case?

A. Even though my testimony concerning the Company's use of the AURORA$_{XMP}$ dispatch model mirrored that filed in the last several general rate case (GRC) filings by Avista, Staff desired additional information in the following areas:

- Why the Company modifies AURORA$_{XMP}$ inputs to match the 3-month average of forward market prices for electricity prices: (**See Section I. "How AURURA$_{xmp}$ Models Market Prices in the Western Interconnect"** starting at page 7; topics below start at page identified.)
  - non-Avista resources, wind, transmission and loads (pg. 8)
  - bidding adders (pg. 9)
  - changes compared to the 2016 v5 database provided with Aurora (pg. 14)
  - AURORA$_{XMP}$ "system settings" for: dispatch, commitment, and resource (pg. 16)
  - changing AURORA$_{XMP}$ software version (pg. 17)
- Changes and impacts of the following relative to the 2015 GRC (UE-150204), including: (**See Section II. "Avista's Resources & Wholesale Contract Changes"**, starting at page 18; topics below start at page identified.)
  - Avista resources (pg. 19)
    - Noxon Rapids Spill (pg. 19); Coyote Springs 2 (pg. 19); Other (pg. 20)
  - Avista contracts (pg. 21)
  - Gas prices (pg. 24)
  - Avista load (pg. 25)
- Overview of Changes in AURORA$_{XMP}$ Costs compared to 2015 GRC (**See Section III.,** starting at page 25.)

- Deltas between Energy Recovery Mechanism ("ERM") and authorized power supply costs (**<u>See Section IV. "Review of Annual ERM Balances</u>**, starting at page 27; topics below start at page identified.)
    - history of ERM results and explanation of the delta drivers (pg. 27)
    - how Aurora optimizes resources to maximize dispatch margin (pg. 28)
- **Why purchase and sale volumes in GRC are less than actual (<u>Section V "Avista Portfolio Optimization"</u>**, starting at page 29.)

It was agreed that supplemental testimony would be filed by the Company on each point.

Q. Please summarize the main points of your supplemental testimony.

A. My supplemental testimony will cover the following points:

1. All presented analyses are based on a comparison of information from my pre-filed direct testimony in this Docket (See. Exh. CGK-1T) and information from the 2015 GRC.[1] I have filed with my supplemental testimony a copy of my workpapers from the 2015 GRC because Staff specifically asked for a comparison to that case.
2. Cumulatively over the life of the ERM (since 2003), in total it has been in the surcharge direction by $37 million.
3. The ERM is highly dependent on natural gas prices and hydro conditions. Natural gas prices have been falling over the past few years while hydro generation has been good when compared to earlier years in the ERM history. These two data points substantially explain why the ERM deferrals have been in the rebate direction in recent years.

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[1] In my Supplemental Direct Testimony, when I refer to the 2015 GRC as it relates to power supply issues, I am referring to the inputs and effect of the November 1, 2015 Power Supply Update in that case, Docket UE-150204.

4. Of the change in power supply expenses in this case, over 80 percent is due to a single known and measurable event--expiration of the Portland General Electric Exchange contract.
5. Sixty-day averaging of natural gas forward prices, and the use of bidding factors and other adjustments to match modeled prices to forward prices is not a new method. It has been used in numerous cases prior to this one.
6. Staff asked for the major drivers of changes between the 2015 GRC and this case. In response to Staff's request, the analysis provided in this testimony (and supporting workpapers) provides support for 98.4 percent of the delta between this case and the 2015 GRC.

Q. Are you sponsoring any exhibits with this supplemental testimony.

A. No, I am not.

Q. Are you providing additional workpapers to detail the work you are presenting in this supplemental testimony filing?

A. Yes. I am providing additional AURORA$_{XMP}$ files documenting the requested studies and analyses performed in this testimony. Further, I am including copies of my filed workpapers from the 2015 GRC (the November 1, 2015 Power Supply Update) that many of these comparisons are based on.

Q. Has the Company made any changes in this case relative to the 2015 GRC that might require an explanation, or are all of the changes data related?

A. The Company has not changed its modeling principles from the 2015 GRC. All changes made are to data that can be audited by comparing 2015 GRC workpapers to workpapers provided in this case, including both AURORA$_{XMP}$ database tables and settings and Company-filed spreadsheets.

Q. Are you providing information in your supplemental testimony based on data and information that was not provided along with the Company's original filing?

A. Yes. Because Staff desired specific comparisons to the 2015 GRC, I am including my workpapers from that filing to assist in their review of this supplemental testimony. Further, because Staff was specifically interested in information regarding ERM balances over time (although not directly pertinent to this filing), I have provided additional information regarding that issue later in my testimony (as well as in my workpapers). However, there is no information being filed related to my original filing in this case that could not be generated using the workpapers provided in my earlier direct testimony.

Q. Please summarize changes between the 2015 GRC and this filing.

A. Table No. 1 below provides 2015 authorized power supply costs, categories of changes made for this filing, and provides the total power supply cost forecast included in this filing. The table below helps describe why costs are higher when including additional power costs described in Company witnesses Mr. Johnson and Mr. Schlect testimony. However, and by a large magnitude, the single-largest driver is the expiration of the PGE exchange contract. Its expiration explains nearly 81 percent of the difference between the power supply level proposed in this case versus that currently authorized based on the Company's 2015 general rate case (GRC) in Docket No. UE-150204.[2]

[2] The 84% delta is calculated by taking the cost of the PGE contract ($16.1 million) and dividing it by the change in Total System Power Supply Cost Forecasts ($158.9 million vs. $139.1 million).

Table No. 1: Summary of Changes to Power Supply Cost

Row	Item	Kalich	Johnson	Net Cost
1	**Authorized 2016 System Power Costs (prior to adjustments)**			**$139,148,766**
2				
3	Palouse Wind		870,000	870,000
4	Energy America/COB Optimization[3]	-2,119,527	3,314,595	1,195,068
5	PGE Exchange Expiration[4]	-3,209,144	19,278,000	16,068,856
6	Lancaster Payments		490,642	490,642
7	Natural Gas & Power Hedges		462,000	462,000
8	Other Long Term Wholesale Contracts[5]	1,638,289	2,193,036	3,831,325
9	Ancillary Services Sales		-25,000	-25,000
10	Natural Gas Transport		-1,107,000	-1,107,000
11	Electric Transmission		167,000	819,790
12	Reduction in Load[6]	-1,629,043		-1,629,043
13	Coyote Springs 2 Upgrade[7]	-615,342		-615,342
14	Allow Noxon Rapids to Spill[8]	-83,930		-83,930
15	Other Resource Changes[9]	2,169,562		2,169,562
16	Changes to Natural Gas/Power Prices[10]	-3,089,848	68,566	-3,021,282
17	Other[11]	-213,287	537,141	323,854
18	Changes in Power Cost (Row 3 to Row 17)	-7,152,270	26,248,980	19,096,710
19				
20	Change in Transmission Revenues[12]			652,790
21	**Total System Power Supply Adjustments**			**19,749,500**
22	**2018-19 Power Supply Cost Forecast (Row 1 + Row 21) - System**			**$158,898,266**
23				
24	Authorized WA Power Supply Costs (PT Ratio 64.71% of Row 1 minus $1.5 million prior direct WA adjustment)			$88,543,166
25	Proposed WA Power Supply Costs (PT Ratio 65.73% of Row 22)			$104,443,830
26	**Proposed WA Power Cost Adjustment (net expense)**			**$15,900,664**
27	***Proposed WA Power Cost Adjustment (revenue requirement)***			***$16,609.000***

[3] ChangeSet7, discussed on page 24
[4] ChangeSet8, discussed on page 24
[5] ChangeSet6, discussed on page 23
[6] ChangeSet10, discussed on page 25
[7] ChangeSet4, discussed on page 19
[8] ChangeSet3, discussed on page 19
[9] ChangeSet5 and XDB WA 2018-19 Filing_80 Years_Test_Year_Load_ChangeSet5.xlsx, discussed on page 21
[10] ChangeSet9, discussed on page 25
[11] These estimates are for changes due to non-identified changes; for the most part these changes are related to changes in electric market prices.
[12] Change in transmission revenues compared to current authorized per Mr. Schlect; proposed transmission revenue is $15.15 million versus current authorized of $15.8 million, an increase in net cost of approximately $653,000.

Q. What power costs from the AURORA$_{XMP}$ dispatch model are used in this rate proceeding?

A. Avista uses AURORA$_{XMP}$ calculated resource fuel costs and net system balancing market purchase and sale costs (AURORA$_{XMP}$ Costs). AURORA$_{XMP}$ Costs, $64,269,942, are provided in my direct testimony in the prefiled workpapers[13]. However, AURORA$_{XMP}$ is not used to value our physical electricity or natural gas contracts. My summarization of costs from the AURORA$_{XMP}$ model include these contract quantities at no cost. In other words, AURORA$_{XMP}$ simply dispatches electricity contracts based on our rights and obligations. Company witness Mr. Johnson prices our physical and financial electricity and natural gas contracts for inclusion in this case. Specifically, he takes dispatched energy quantities from the AURORA$_{XMP}$ model and values them at their contract prices. Mr. Johnson also includes the costs of physical and financial natural gas contracts in his work.

Q. Why are contracts modeled in AURORA$_{XMP}$ since they do not directly impact AURORA$_{XMP}$ Costs?

A. Mr. Johnson is responsible for the calculation of total power costs. Mr. Johnson is a wholesale marketing manager, and a significant portion of his work involves contracting for and managing the contracts for which he is testifying to.

AURORA$_{XMP}$, on the other hand, must include all physical electricity contracts to ensure market purchase and sale quantities are representative of our AURORA$_{XMP}$ Costs in the proforma period. Absent this information, AURORA$_{XMP}$ would not be able to correctly estimate hourly net energy positions to sell any leftover energy or buy hourly shortfalls.

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[13] XDB WA 2018-19 Filing_80 Years_Test_Year_Load.xlsx

Q. Why do you include wholesale contract costs in your exhibit?

A. This analysis is provided for informational purposes as they are not used to arrive at any values used in my work; however, they remain in the exhibit because we use this data in other Company analyses not relative to this case. For example, when we value a new resource in an integrated resource plan, it is important to estimate the revenues associated with our contracts. And because we use the same database for all of our analyses, including rate case filings, keeping the revenue information in the database is valuable even if not used here.

Q. Please summarize the delta between the 2015 GRC filing and this filing?

A. Authorized AURORA$_{XMP}$ Costs in the 2015 GRC are $71,422,212[14]. In this filing the costs are $64,269,942, resulting in $7,152,270 lower costs as noted in Table No. 1 above. Therefore AURORA$_{XMP}$-modeled costs in this case *are lower* than in the 2015 GRC.

I. How AURORA$_{XMP}$ Models Market Prices in the Western Interconnect

Q. Why do you align AURORA$_{XMP}$ market prices to forward electricity prices?

A. Aligning AURORA$_{XMP}$ market price forecast to forward prices ensures the model values Company resources and load obligations based on current market conditions. The Washington Commission stated its support for the methodology used in this case in the 2005 Avista GRC Order No 5, paragraph 106, Docket No. UE-050482. Specifically, the Commission stated:

> *We find that it is appropriate for bidding factors to be included in AURORA. It is important to determine accurate estimates of actual costs that the Company will experience in the near and intermediate terms. Bidding factors, correctly applied, promote more accurate estimates for projected power supply costs. We also find the*

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14 As provided in compliance filing workpapers as "XDB WA 2016 Filing_80 Years_Test_Period_Load_101915.xlsx"

> *use of a 3-month average of forward prices, consistent with the methodology the Commission has previously approved, is acceptable.*

The paragraph also documents Commission support for using bidding adders in this effort. The strong level of Commission support for using bidding factors is illustrated by its requiring Avista to update bidding factors for final ratemaking. See the following paragraph from the same order, at paragraph 107.

> *Finally, however, we find that the Settlement Parties' failure to update the bidding factors to harmonize them with the updated gas costs on which the settlement is based is a mistake that undermines the purpose of bidding factors. We require Avista's pre-compliance rerun of AURORA to reflect our finding that updated power costs require updated bidding factors to avoid a potential mismatch between gas and electric prices.*

<u>Non-Avista Resources, Wind, Transmission and Loads</u>

Q. Why are non-Avista assumptions for loads, resources, transmission and markets important in AURORA$_{XMP}$?

A. Avista models all Western Interconnects loads, resources, and transmission to properly emulate the electric marketplace Avista operates within. The Company uses a combination of its own internal data, the EPIS-provided AURORA$_{XMP}$ database, data provided by the Northwest Power and Conservation Council and the Bonneville Power Administration, and SNL Financial to develop its database for this case.

It is important to accurately model the entire Western Interconnect to ensure reasonable dispatch of Avista resources under varying proforma-period market conditions that are not perfectly known. For example, in the event of below-normal hydro production in the region, wholesale market prices likely will respond by rising. To correctly reflect portfolio value for customers in the case, it is important for non-hydro Avista plants to increase their dispatch. Without a dynamic full marketplace model that reflects this condition, AURORA$_{XMP}$ would under-dispatch Avista thermal resources and over-state costs in low water years. The inverse is true for high hydro conditions. Notwithstanding matching model prices to forward prices, Avista includes regional assumptions to model fundamental market dynamics such as generation characteristics, loads, transmission, and state policies such as California Assembly Bill 32. Each of these can impact how AURORA$_{XMP}$ dispatches regional resources against loads to emulate the projected power supply marketplace in which Avista operates and dispatches its loads.

Q. Do non-Avista related market assumptions impact Avista power costs in AURORA$_{XMP}$ modeling?

A. To ensure non-Avista assumptions do not affect Avista power costs, bidding factors and other adjustments are employed to ensure modeling prices equate to forward market prices.

<u>Bidding Adders</u>

Q. In past filings, bidding factors (now called resource dispatch margins by the AURORA$_{XMP}$ vendor) were used to match forward prices. Can bidding factors alone match AURORA$_{XMP}$ electricity market prices to forwards?

A. It depends on the change required to align prices, but generally bidding factors are not sufficient to match prices. This is because high resource dispatch margins sometimes necessary to align prices can cause resources to dispatch in a manner not consistent with history. Therefore bidding adders are one tool. Other data assumptions were modified.

Q. Describe changes beyond bidding factors made in AURORA$_{XMP}$ to align modeled electric prices with forward electric prices.

A. Avista made several changes to regional data and model settings to align electricity prices with forward prices, and include: seasonal resource dispatch margins (bidding factors), adjusting congestion and costs to transmission from the Northwest to California, adjusting Northwest hydro shaping factors, and modifying Northwest electricity loads. These changes together created a close replication of forward prices in the AURORA$_{XMP}$ model.

Q. Please explain seasonal resource dispatch margins (bidding factors).

A. Resource dispatch margins, previously called bidding factors, add a premium to the dispatch margin a generation resource requires before it will dispatch. Unless a separate bidding factor is specified for an individual resource, the dispatch margin is applied globally to all resources AURORA$_{XMP}$ commits and dispatches.

Table No. 2 details dispatch margins in both the 2015 GRC filing and this filing. Changes were a necessary part to adjust AURORA$_{XMP}$ market prices to match forward prices.

Table No. 2: Dispatch Margin Percentages

Filing	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2015 GRC Compliance Filing	5.0	5.0	0.0	0.0	7.5	7.5	7.5	7.5	5.0	0.0	5.0	5.25
2017 GRC Filing	5.0	5.0	5.0	3.0	0.0	2.0	5.0	5.0	5.0	5.0	5.0	5.0

The intertie between California and the Northwest historically allowed excess energy to flow between regions. Over the last five years the intertie on average has been de-rated to 80% of its maximum (see Kalich workpaper “ACDC Capability and usage.xlsx”). This de-rating occurs in all months. The effect of path derating is lower electricity prices in the Northwest because less energy may be exported to California. Avista needed only to adjust export limits in the May through August timeframe for this case. When we did so, the five-year average of historical path capacities was used. In the 2015 GRC, the path uses its maximum rating for all months at a charge of $5.86 /MWh in 2016. This rate filing uses $6.98/MWh in 2018 and $7.24/MWh in 2019. These higher rates reflect inflationary changes since the 2015 GRC, and expected compliance costs of California's Assembly Bill 32.[15] The ultimate price of transmission to California is not greatly material to this case, since Avista prices all of its resources at the Mid-C, and market prices in $\text{AURORA}_{\text{XMP}}$ are tied to Northwest forward prices.

Northwest hydro shaping factors impact the amount of hydro energy the model dispatches in the on- versus off-peak hours. Consistent with past cases, Avista hydro shaping factors are set to ensure on- and off-peak generation levels equal to the latest five-year Avista-actual results. Just as in the 2015 GRC, and in prior cases, for non-Avista resources, shaping factors are adjusted to assist in matching Northwest electric prices at the Mid-Columbia trading hub with forward market prices at this location.

Avista also increased forecasted loads to better match modeled electric prices. Loads included in the default $\text{AURORA}_{\text{XMP}}$ database from EPIS are derived from historical periods. Avista increased default loads in Washington, Oregon, Idaho, and Montana by the amounts included in Table No. 3 below.

Table No. 3: Regional Load Changes

Month	Percent Change	Month	Percent Change
January	+10%	July	0%
February	+10%	August	+8%
March	+8%	September	+8%
April	+7%	October	0%
May	0%	November	+5%
June	0%	December	+8%

[15] California Assembly Bill 32 is the state's law to limit carbon emissions to 1990 levels by 2020.

Q. Did you run AURORA$_{XMP}$ without these market adjustments? And if so, what were the results?

A. Yes. A comparative study was run, including: no dispatch margin adjustments, no load adjustments, and default hydro shaping and transmission path ratings from the five year average filed in this case. Without the adjustments, Mid-Columbia (Mid-C) prices are nearly ten percent lower ($21.44 per MWh as compared to forward price of $23.21 per MWh). The resulting AURORA$_{XMP}$ Costs were higher by $2,770,717. Costs are higher because Avista is surplus during the proforma period, and such sales are valued at lower prices. These adjustments are included in the supplemental AURORA$_{XMP}$ project file workpapers as ChangeSet1.

Q. Are there any other changes similar to resource dispatch margin used in the AURORA$_{XMP}$ model, and why are they included?

A. Avista includes negative "bidding adders" to most hydro projects in the Western Interconnect. Avista has used this functionality in previous rate filings, including those back at least to 2012, to capture the impacts of negative prices when the Northwest is oversupplied.[16] The bidding adder simply changes the dispatch order of hydro facilities in the overall resource stack. Without bidding adders, hydro projects, otherwise entered as zero-cost resources, would spill energy and electric prices would not fall below zero as they actually do. In an effort to protect fisheries, many hydro projects do not have license rights to spill water, or if they do, it is greatly limited. For these projects, negative bidding adders force full dispatch, even in negative market price conditions. The typical bidding adder for hydro

[16] In past filings this function may have been entered as negative Variable O&M due to limited options to change dispatch order as compared to the current version of AURORA$_{XMP}$.

projects is negative $50.00 per MWh. Avista hydro resources are given a lower bidding adder of negative $75.00 per MWh to ensure these resources do not dispatch down, with an exception to Noxon Rapids described later in testimony.

Some regional hydro resources have the ability to spill, but this information is not publicly available and so a lower bidding adder on a portion of the hydro resource stack is used to prevent market prices from going directly to negative $50.00 in the event of oversupply. To help the model shape generation and resulting market prices to emulate actual market conditions, bidding adders for approximately 13,600 MW of hydro include bidding adders of between negative $10 and negative $16 per MWh.[17]

Q. Do other resources receive negative bidding adders?

A. Yes, PURPA resources have a bidding adder of negative $45 per MWh so that these resources will not turn off (or down) at low load conditions. PURPA contracts cannot be reduced for low-price market conditions. In addition to these resources, wind and solar resources receive a negative bidding adder, located in the "VAR Cost Mod1" column, to model Production Tax Credits (PTC) and renewable values.[18]

Q. Is the use of bidding adders in this case a change in methodology relative to prior filings?

A. No, it is the same as prior cases going back at least to 2012. However, we did relocate the negative $75/MWh "VAR Cost Mod1" adjustment made to Avista's hydro units

[17] Total modeled hydro capacity in the Western Interconnect is 66 GW.
[18] The "VAR Cost Mod1" is an AURORA$_{XMP}$ feature equating to an adder (or subtractor) to the marginal cost of the unit to influence the units dispatch price and works the same as bidding adders by changing the units' variable cost of dispatch. Avista uses "VAR Cost Mod1" feature for PTC and "VAR Cost Mod2" for renewable energy credits.

to the bidding adder column in AURORA$_{XMP}$. This change makes no impact on power supply costs.

Q. Why not use the "must run" logic in AURORA$_{XMP}$ to change the dispatch order of hydro units?

A. The "must run" logic forces units to dispatch at minimum generation levels. For the resources described above, the "must run" would dispatch the resources to zero, their minimum generation level. The plants would not be forced to dispatch during over-supply events, leading to an incorrect representation of the wholesale marketplace.

Q. Did you run the AURORA$_{XMP}$ model without bidding adders, and if so what were the results?

A. Yes. AURORA$_{XMP}$ Costs were $180,072 (0.3%) lower than the results filed in this case. The model created slightly higher average Mid-Columbia prices during off peak hours, resulting in higher revenue for surplus generation. Turning this functionality off resulted in hydro spill at Avista facilities, which violates our license rights. These adjustments are included in the supplemental AURORA$_{XMP}$ project file workpapers as ChangeSet2.

<u>EPIS AURORA$_{XMP}$ Database Changes</u>

Q. Describe any high-level changes you made to the default AURORA$_{XMP}$ database (North_American_DB_2016_v5.xdb) provided by EPIS?

A. In addition to the changes discussed above, Avista modifies the default AURORA$_{XMP}$ database in ways affecting resources it does not own or control. These changes include removal of all non-Western Interconnect resources, loads, and transmission information since these resources do not impact the runs.[19] As in past cases, hydro energy data are replaced with the 80 year record provided by the Bonneville Power Administration and Northwest Power and Conservation Council hydro constraint data replace default values.[20] We also update fuel prices to reflect current market conditions, namely the three-month average of natural gas prices.[21] We modify zonal operating reserve levels, adding a new zone to reflect the California-Oregon border trading hub, and we eliminate the fuel table and instead place this data directly in the resources table. Further, this filing benefits from a new feature in AURORA$_{XMP}$ to estimate regional resource planned maintenance. Prior to this enhancement, maintenance was modeled as a simple de-rate to plant capacity. The impact of this change and other non-Company resources and loads is irrelevant due to Avista's matching of market price results to the forward market, but overall regional plants dispatch in a manner more representative of history.

In addition to these changes, Avista maintains its own table of Western Interconnect generation resources. It includes updates to regional resources to reflect retirements and new installations. It also consolidates hydro resources by plant (rather than unit), and consolidates solar resources located in each load area. The table includes estimated regional resources built for renewable resource mandate compliance, customer generation, and demand response, although these additions are trivial given the small level of additions in early future years.[22]

[19] The AURORA$_{XMP}$ database includes data for all of North America so that all clients of the software vendor can operate their systems. When running only the Western Interconnect, those resources outside of the area can be eliminated to simplify management of the database.
[20] NPCC hydro constraint data was included in the 2015 GRC, but not used. This filing uses the available data.
[21] This methodology first was approved by the Commission in the 2005 Avista GRC Order No 5, page 44, paragraph 106.
[22] Resource additions like these are reflected because Avista uses the same AURORA$_{XMP}$ database for all of its study work, including Integrated Resource Planning. These other studies require looking further into the future where these assumptions become more significant to the overall market.

Further, Avista estimates generation and heat rate at minimum and maximum generation levels, minimum operating levels, ramping rates for dispatchable resources using hourly government-reported continuous emission monitoring (CEMS) data, generating availability data system (GADS) information for unit forced outage rates. Production tax credits for wind resources are added based on vintage. Coal prices, variable cost, and fixed cost data are determined using data reported to the U.S. Energy Information Administration. For natural gas resources, fuel prices are determined by pipeline interconnect. Regional wind shapes use data from National Renewable Energy Lab (NREL) and Bonneville Power Administration (BPA) hourly wind history.

Q. What information from the default AURORA$_{\mathrm{XMP}}$ database did you include in the database for this case?

A. Avista uses regional forecasted loads, transmission (links), areas, non-Northwest or California hydro data and logic, and resource emission rates. But some of this data is modified to ensure an accurate reflection of current market conditions.

System Setting Changes

Q. Please describe any other changes you made to the setup of the model that differs from the previous filing, such as dispatch settings, commitment settings, or solution settings.

A. Avista made changes to "Dispatch Settings" from the 2015 GRC, including changing the "min gen back down penalty" value from 200 to 500.[23] We also included the "remove penalty adders from pricing" option. This logic removes non-commitment penalty

[23] 500 is the default amount provided by EPIS, and so Avista desired to return this value to its default for the filing.

adders from influencing market prices. Avista chose not to include this feature as it changes market prices in a way not tied to the cost of the region's unit on the margin. Avista made only one change to "Commitment Settings" data from the prior case. This change replaces the "fixed non-commit penalty (%)" back to the EPIS default value of 2900 (from the value of 2000 used in the prior case). This input is discretionary and we found a return to the EPIS default value in this case was possible.

A number of "Solution Settings" were changed as compared to the last case. We changed default units from kilowatts (kW) to megawatts (MW) and we selected the "treating resource bidding adder input as nominal." The kW to MW is a simple data format change. The change of bidding adder to nominal simply removes the $\text{AURORA}_{\text{XMP}}$ default inflation assumption from the filing since we already have input inflation-adjusted values into the model for this case.

Q. Do these adjustments impact Avista's power costs?

A. With these changes, $\text{AURORA}_{\text{XMP}}$ Costs increase by $44,850, or approximately 0.03 percent of filed power supply costs. These changes are included in filed work papers in the $\text{AURORA}_{\text{XMP}}$ file "AVA_WA_2018-2019_GRC_2016 settings.apz." This is because $\text{AURORA}_{\text{XMP}}$, through the various changes including these last ones, matches market prices to forward prices. As long as forward prices and modeled prices are similar, these adjustments will have no material effect on the results.

EPIS $\text{AURORA}_{\text{XMP}}$ Version Changes

Q. In filed testimony, you mentioned the version of $\text{AURORA}_{\text{XMP}}$, what was the prior version and describe any changes?

A. Yes, EPIS releases new versions of AURORA$_{XMP}$ periodically to add features and fix issues it has found in the model. Databases and setup configurations are not necessary compatible between versions, meaning Avista regularly must update its datasets to ensure compatibility and take advantages of enhancements. The 2015 GRC filing used AURORA$_{XMP}$ version 11.5.1043; this filing uses version 12.2.1050. Version 11.5.1043 was released November 11, 2014; version 12.2.1050 was released February 24, 2017. Since the 2015 GRC filing and this filing, EPIS has released three new versions of the model and 57 updates. EPIS keeps a log of changes made to each version of AURORA$_{XMP}$ on its website, and documents enhancements.

Q. Were you to run your present case in the older version of AURORA$_{XMP}$ would you expect power costs to be substantially different?

A. No. As described above, there are compatibility issues between AURORA$_{XMP}$ model and database versions. While a run made in the older version almost certainly would arrive at a different value, once settings are made to align wholesale market prices and resource dispatch the results would be the same. The new version is not compatible due to AURORA$_{XMP}$ enhancements made by the vendor in dispatch logic and run setup from the model used in the prior case.

II. Avista's Resources & Wholesale Contract Changes

Avista Resources

Q. Has the Company made any resource portfolio changes since the 2015 GRC Compliance Filing?

A. Yes. Avista included several updates to the data to reflect updated information. These changes relate to thermal and hydro resources and wholesale contracts.

1. Noxon Rapids Spill

Q. Describe any modeling changes made to Noxon Rapids and explain their impact to power costs?

A. Noxon Rapids benefits from two data changes. First is modeling the plant on the unit instead of plant level. In other words, we represent the plant as five separate units. The second is allowing the plant to spill water during negative price events. Please reference text earlier in my testimony to better understand this data change. This change better matches actual operations. This data change is the result of an agreement reached between ICNU and the Company during the 2016 GRC (UE-160228) rate filing to enable the plant to honor license obligations and to be consistent with actual Avista hydro operations. Unit-level representation was necessary since up to two units can spill water when prices fall below zero.

Q. What is the effect of this change in Noxon operations?

A. AURORA$_{XMP}$ Costs fall by $83,930. Average generation at the plant falls by 31,219 MWh per year. These adjustments are included in the supplemental AURORA$_{XMP}$ project file workpapers as ChangeSet3.

2. Coyote Springs 2

Q. Please describe any changes to the Coyote Springs 2 plant, why the changes were made, and what their impacts to modeled AURORA$_{XMP}$ Costs were.

A. During its 2016 maintenance cycle, the Coyote Springs 2 plant received an enhanced gas path upgrade. The upgrade increased its capacity and improved its heat rate. Table No. 4 below illustrates the improvements to efficiency and capacity, resulting in lowered AURORA$_{XMP}$ Costs of $615,342. These adjustments are included in the supplemental AURORA$_{XMP}$ project file workpapers as ChangeSet4.

Table No. 4: Coyote Springs 2 Capacity and Heat Rate Changes

Month	Capacity Addition (MW)	Heat Rate (Btu/kWh)	UBB Segment Size (Percent)
Jan	15.678	-11	0.2
Feb	15.940	-11	0.2
Mar	16.290	-10	0.2
Apr	16.475	-10	0.2
May	16.580	-10	0.2
Jun	16.686	-9	0.2
Jul	16.610	-10	0.2
Aug	16.637	-9	0.2
Sep	16.658	-8	0.2
Oct	16.415	-8	0.2
Nov	16.110	-7	0.2
Dec	15.639	-7	0.2

Other Resources

Q. Are there other resource data changes made to the AURORA$_{XMP}$ model in this filing, and what are their impacts to power costs?

A. Yes. Avista made a number of small data changes to better reflect our system. Each is based on previous case methodology and precedent. We updated forced and maintenance outages to reflect the latest five year average for our system. We update to the most current fuel forecasts for Colstrip and Kettle Falls. We updated hydro shaping factors to the latest five year average and updated station service consumption to latest five year average. These changes are documented in the filed workpapers of my direct testimony. Other changes include minor updates to heat rates, start-up costs, variable operation and maintenance costs, shut down penalties, minimum down time, and non-cycling percentages where appropriate. These updates in total increase AURORA$_{XMP}$ Costs by $2,169,562 relative to 2015 GRC assumptions. These adjustments are included in the supplemental AURORA$_{XMP}$ project file workpapers as ChangeSet5[24].

Q. Can you be more specific to changes in modeling the Kettle Falls plant?

A. Yes, the 2015 GRC Compliance Filing modeled Kettle Falls as a "must run" resource. The initial runs performed for this case did not operate the plant similarly to historical and expected future conditions. To get a better representation of expected operations, the "must run" option was replaced with a negative $10 per MWh bidding factor. The other minor change not already documented is returning the plant's non-cycling percent back to the five percent AURORA$_{XMP}$ default value. These adjustments are included as part of the cost calculation in the prior question.

<u>Avista Contracts</u>

Q. Describe any changes to power contracts and their impacts on power costs.

A. Avista updates all contracts over the proforma term to account for expiring and new contracts. Any contracts without known and/or fixed schedules use five-year historical averages (i.e., PURPA contracts) or expected generation (i.e., WNP-3). Table Nos. 5 and 6 below details changes in aMW between contracts in the 2015 GRC compliance filing and this case, and contains additional detail for each contract.

[24] These change also update the fixed Colstrip Fuel Cost in supplemental workpaper "XDB WA 2018-19 Filing_80 Years_Test_Year_Load_ChangeSet5.xlsx". Colstrip fuel cost detail can be found in prefiled workpapers "201512 2016 Final AOP Coal Cost Summary.xlsm"

Table No. 5: Wholesale Contract Changes (aMW) [2017 GRC – 2015 GRC]

Contracts	Ann	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Canadian Entitlement	-2.6	-2.6	-2.4	-2.5	-2.7	-2.9	-2.8	-2.7	-2.8	-2.5	-2.8	-2.7	-2.3
COB Optimization	0	0	0	0	0	0	0	0	0	0	0	0	0
Energy America	9.9	30.0	30.0	30.0	30.0	0	0	0	0	0	0	0	0
Douglas Settlement	-2.0	-1.9	-1.6	-3.2	-5.8	-0.0	-1.0	-1.3	-2.2	-2.0	-2.2	-1.8	-1.8
Load Following & Integration	0	0	0	0	0	0	0	0	0	0	0	0	0
Nichols Pumping	3.3	6.8	6.8	6.8	6.8	0	0	0	0	0	0	6.8	6.8
Palouse Wind	0	0	0	0	0	0	0	0	0	0	0	0	0
PGE Capacity Exchange	-0.1	-2.4	0.6	1.8	-0.8	-0.4	1.3	-2.4	1.8	1.3	-2.4	1.3	-0.2
Small Power	-0.1	0.2	0.8	0.1	-0.1	-0.5	-0.8	-0.9	-0.5	-0.3	-0.0	0.4	0.8
Spokane Waste-to-Energy	-1.2	-2.5	-1.8	-1.1	1.1	-1.1	-2.2	-0.5	1.4	-0.2	-1.4	-2.5	-3.6
Stimson Lumber	-0.2	-0.4	-0.3	-0.3	0.2	0.4	-1.0	-0.2	-0.1	-0.2	-0.2	-0.6	-0.3
Upriver	-0.2	0.1	0.4	0.5	0.0	-0.4	-1.2	-0.5	-0.2	-0.2	-0.3	0.0	0.1
WNP-3	0.2	-0.2	3.9	0.1	0	0	0	0	0	0	0	-0.4	0.9
ST Market Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0
ST Market Sales	0	0	0	0	0	0	0	0	0	0	0	0	0
Financial Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0
Financial Sales	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Contracts	**6.9**	**7.1**	**36.3**	**32.1**	**28.7**	**-5.0**	**-7.8**	**-8.4**	**-2.6**	**-4.2**	**-9.3**	**0.5**	**0.4**

Table No. 6: Overview of Wholesale Contract Changes

Contract	Description of Change	Workpaper
Canadian Entitlement	Updated to reflect BPA white book estimates for Avista's share of Mid-C hydro projects	N/A
COB Optimization	Due to Energy America contract reduction, the optimization increases from 10 MW to 40 MW	N/A
Energy America	Contract reduces deliveries beginning January 2019 from 50 MW to 20 MW	N/A
Douglas Settlement	Update to forecast schedule deliveries	DOPD Settlement.xlsx
Load Following & Integration	Increased on-peak energy to include 3rd party intra hour sales agreements	N/A
Nichols Pumping	3rd party contract ends, but 1 MW obligation will be retained.	N/A
Palouse Wind	Change link from weekly table to hourly table- no change in data	N/A
PGE Capacity Exchange	Contract expired	N/A
Small Power	Updated to 5 year average deliveries & added community solar facility	Small Power.xlsx
Spokane Waste-to-Energy	Updated to 5 year average deliveries	Spokane_Waste_to_Energy.xlsx
Stimson Lumber	Updated to 5 year average deliveries	Stimson Lumber.xlsx
Upriver	Updated to 5 year average deliveries	Upriver Gen & Load.xlsx
WNP-3	Update to forecast schedule deliveries	WNP3.xlsx
ST Market Purchases	Updated to known contracts	Term deals_030817.xlsx
ST Market Sales	Updated to known contracts	Term deals_030817.xlsx
Financial Purchases	Updated to known contracts	Term deals_030817.xlsx
Financial Sales	Updated to known contracts	Term deals_030817.xlsx

Q. Describe changes to the Mid-Columbia hydro contract rights?

A. The 2015 filing included 110.2 aMW of Mid-Columbia contract generation as compared 108.3 aMW in this filing.[25] The reduction reflects a change due to expiration of our long-term Wells contract share. A new contract with Douglas PUD was signed, but we were unable to retain the same delivery levels. See the following Table No. 7.

Table No. 7: Avista Share of Wells

18-May	18-Jun	18-Jul	18-Aug	18-Sep	18-Oct	18-Nov	18-Dec	19-Jan	19-Feb	19-Mar	19-Apr
3.34%	3.34%	3.34%	3.34%	3.02%	3.02%	3.02%	2.35%	2.24%	2.24%	2.86%	3.25%

Q. What is the net impact of the contract changes described above to AURORA$_{XMP}$-modeled power supply costs?

A. I will describe the COB Optimization, the Energy America sale, and the PGE Exchange further below. The impact of the contract changes excluding these three is an increase of $1,638,289 in AURORA$_{XMP}$ Costs. This increase is driven primarily by a net of 4.7 aMW less contract generation relative to the 2015 GRC.[26] These adjustments are included in the supplemental AURORA$_{XMP}$ project file workpapers as ChangeSet6.

Q. Can you be more specific to the changes made between the 2015 GRC and this filing for COB Optimization and the Energy America Sale?

A. The 2015 GRC included a total of 60 MW of COB energy sales, reflecting our expected sales to this hub. Customers benefit from sales at this traditionally higher-valued trading hub. In the 2015 GRC 50 MW was a sale to Energy America for [redacted] per MWh over the Mid-C index price. The remaining 10 MW was assumed to be from short-term market sales ("COB Optimization") at COB rather than the Mid-C trading hub.

[25] Excluding Canadian Entitlement.
[26] This impact is due to wholesale contracts being included in AURORA$_{XMP}$ at a zero price. Mr. Johnson includes the costs of these contracts in his testimony.

In 2019 the Energy America contract quantity falls from 50 MW to 20 MW. To reflect this change and maximize transmission rights to the hub, the COB Optimization rises an additional 30 MW beginning in 2019 to keep total deliveries at 60 MW, consistent with the 2015 GRC.

This expiration decreased $\text{AURORA}_{\text{XMP}}$ Costs in the case by $2,119,527 as compared to previous contract level. This reflects the model having four additional months where 30 MW of additional energy is not sold at zero-cost. These adjustments are included in the supplemental $\text{AURORA}_{\text{XMP}}$ project file workpapers as ChangeSet7. Accounting for the revenue side of these transactions, as is done by Mr. Johnson in his testimony, the net impact to power supply cost is $1,195,068 relative to the 2015 GRC. This amount includes changes the Mid-Columbia index portion of the contract. On a net basis, this reduction in deliveries increases power supply costs by $367,800.

Q. Please describe the impact of the loss of the PGE Exchange Contract?

A. The PGE Exchange contract expired at the end of 2016, reducing $\text{AURORA}_{\text{XMP}}$-modeled power supply expenses. However, the revenues of this contract greatly exceeded the costs modeled in $\text{AURORA}_{\text{XMP}}$. The contract expiration decreases $\text{AURORA}_{\text{XMP}}$ Costs by $3,209,144 in this case relative to the 2015 GRC. However, we also lost more than $19.278 million in revenues, meaning the net increase in power supply costs of approximately $16.069 million in this case. These adjustments are included in the supplemental $\text{AURORA}_{\text{XMP}}$ project file workpapers as ChangeSet8.

<u>**Natural Gas Price Changes**</u>

Q. What is the impact on $\text{AURORA}_{\text{XMP}}$ Costs where only natural prices were changed from the 2015 GRC?

A. The 2015 GRC compliance filing's Stanfield annual average natural gas price was $2.77 per dekatherm. This filing's Stanfield annual average natural gas price is $2.60 per dekatherm. Further, and consistent with previous filings, daily fuel shapes were updated to the latest five year average. This case benefits from lower natural gas prices, but AURORA$_{XMP}$ Costs rise by $3,089,848, due to a lower value for the Company's surplus sales.[27] These adjustments are included in the supplemental AURORA$_{XMP}$ project file workpapers as ChangeSet9.

Avista Load Changes

Q. What is the change to AURORA$_{XMP}$ Costs where only Avista loads are not changed from the 2015 GRC?

A. Weather adjusted loads in the 2015 GRC were 1,052.5 aMW as compared to 1,045.2 aMW filed in this case, a reduction of 7.3 aMW. If Avista loads were the same as the 2015 GRC, the AURORA^{XMP} Costs would be $1,629,043 higher. These adjustments are included in the supplemental AURORA$_{XMP}$ project file workpapers as ChangeSet10.

III. Overview of Changes in AURORA$_{XMP}$ as Compared to the 2015 GRC

Q. Describe the impact on Avista non-hydro resource dispatch between the 2015 GRC Compliance filing and this filing?

A. Non-hydro dispatch in the 2015 GRC compliance filing was 578.1 aMW for AURORA$_{XMP}$ Costs of $95.53 million. This filing is 584.4 aMW for AURORA$_{XMP}$ Costs of $96.87 million. The average fuel cost is [redacted] per MWh in this filing vs [redacted] per MWh in the 2015 GRC. The following Table No. 8 presents a summary of differences by plant.

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[27] This scenario is for information purposes and does not align prices with forward market as required in prior Commission orders

The total change to fuel costs is an increase of $1.3 million. The largest contribution to this difference is increased costs for peaking projects, as in today's marketplace these units run in more hours than in past filings. Costs are lower for baseload gas plants.

<u>Table No. 8: Non Hydro Dispatch & Costs</u>

Facility	2017 GRC ($MWh)	2015 GRC Compliance Filing ($/MWh)	$/MWh Percent Change	Fuel Cost Change ($000)
Boulder Park	[redacted]	[redacted]	-5.8%	140
Colstrip	[redacted]	[redacted]	6.1%	-615
Coyote Springs 2	[redacted]	[redacted]	-5.1%	-2,320
Kettle Falls	[redacted]	[redacted]	-16.4%	496
Kettle Falls CT	[redacted]	[redacted]	-4.7%	356
Lancaster	[redacted]	[redacted]	-4.6%	-2,414
Northeast	[redacted]	[redacted]	-5.8%	1,199
Rathdrum	[redacted]	[redacted]	2.9%	4,494
Pullman Storage (Turner)	[redacted]	[redacted]	N/A	N/A
Total	[redacted]	[redacted]	**0.6%**	**1,336**

Q. What are system balancing sales and purchases, and are there changes between this filing and the 2015 GRC Compliance Filing?

A. System balancing sales and purchases are market purchases and sales from my pre-filed workpapers[28]. The energy quantities are the summary of the hourly calculated differences between load obligations when compared to our net wholesale contract rights and dispatch of our resources. Where Avista has excess resources, the model sells the power at the hourly Mid-C market price; if Avista is economically or physically short power for the hour, the model buys power at the hourly market price at Mid-C. The following Table No. 9 summarizes the differences between the two filings. This filing shows Avista is selling a net of 15 aMW more to the wholesale market than the 2015 GRC. This change is due to lower

[28] XDB WA 2018-19 Filing_80 Years_Test_Year_Load.xlsx

loads, higher net wholesale contracts, and higher dispatch by Avista's generating resources. The value of additional sales from the 2015 GRC is approximately $8.5 million.

Table No. 9: System Balancing Sales & Purchases

Item	2017 GRC	2015 GRC Compliance Filing	Delta
	aMW	**aMW**	**aMW**
Market Purchases	[redacted]	[redacted]	[redacted]
Market Sales	[redacted]	[redacted]	[redacted]
Net	[redacted]	[redacted]	[redacted]
	$/MWh	**$/MWh**	**$/MWh**
Market Purchases	[redacted]	[redacted]	[redacted]
Market Sales	[redacted]	[redacted]	[redacted]
Net	[redacted]	[redacted]	[redacted]
	($000)	**($000)**	**($000)**
Market Purchases	[redacted]	[redacted]	[redacted]
Market Sales	[redacted]	[redacted]	[redacted]
Net	[redacted]	[redacted]	[redacted]

IV. Review of Annual ERM Balances

Q. Please provide a historical comparison between actual power costs and costs authorized by the Commission since 2003?

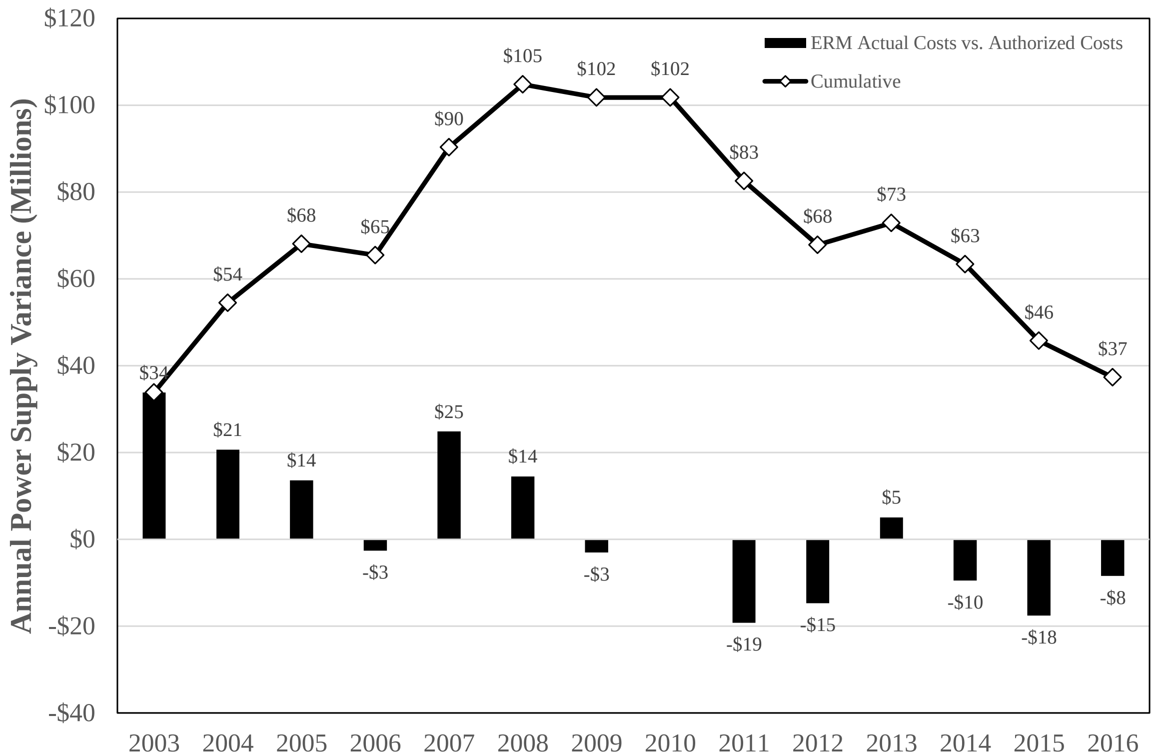
A. Avista's actual costs compared to Commission-authorized levels are shown in Figure No. 1 below. The chart goes back to 2003, the first year of the ERM, and shows the actual Avista ERM balance across its history is $37.3 million higher than authorized by the Commission. The average difference between actual and authorized each year has been $2.9 million.[29] Since 2011 Avista has been rebating customers due to costs being lower than actuals mainly because of falling gas prices and favorable hydro production. This is the

[29] Does not include 2010. As part of the Settlement Stipulation approved in Docket No. UE-100467, the Company agreed there would be no deferrals under the ERM for 2010 in either the rebate or surcharge direction. See page 13, paragraph 8, of the Settlement Stipulation in that case

inverse of what was experienced between 2003 and 2007, when actual costs were mostly higher than authorized due to rising natural gas prices.

At one point the cumulative ERM balance reached $105 million to the Company's detriment; the ERM never has in total been to the Company's favor. Also it is interesting to note that ERM balances, while in the Company's favor in recent years, are less volatile than in the past. In other words, if anything our filings are more accurate relative to what is actually experienced. Data supporting Figure No. is provided in the Company's workpapers.

Figure No. 1: Actual Costs as Compared Actuals[30]



Q. How AURORA$_{XMP}$ maximize the value of Avista resources to the benefit of customers to capture their overall value?

[30] Ibid.

A. AURORA$_{XMP}$ by design maximizes the value of generation assets it emulates. This means that for given market conditions the model operates each resource available to it in a manner that lowers costs and generates the highest revenues. To see this impact, one needs only to look at the results over the 80 water years modeled for the case. Avista has two major asset classes, thermal and hydro. In lower hydro years thermal facilities are operated more frequently to take advantage of higher market prices. In high water years, these same resources operate less because their value in the marketplace is lower. Hydro facilities also are shaped to maximize their values - energy is shifted into high-value one-peak periods.

V. Avista Portfolio Optimization

Q. Can you explain why actual wholesale purchases and sales volumes are substantially larger than those transactions modeled in AURORA$_{XMP}$?

A. In AURORA$_{XMP}$ each hour of the proforma year is balanced once. In other words, loads are compared to resources and a balance is calculated. Many hours are surplus to loads while many others are deficit. The total of the 8,760 hours of the proforma period are summed up and represent the net wholesale purchases and sales reported in my testimony and exhibits. This is done 80 times, once for each hydro year.

In actual operations, and as part of its risk management policy, the Company will balance its positions in the forward market as part of its efforts to control costs. Once a position has been taken (e.g., a 25 MW purchase contract), it is possible for market prices to change and dispatching one of our gas plants to become more cost effective than that market purchase. Where this is the case, the Company will purchase gas for the power plant and sell the earlier contract to another party, reducing overall power supply expenses. This can occur many times prior to actual power delivery.

Over the course of time these purchases and sales for the same forward period in time can generate a large volume of sales and purchases. However, the *net* of all purchases and sales are reasonably similar to the proforma period. It is important to look at nets, since they help explain the true position of the Company. It is possible that differences occur in net purchases and sales where, for example, natural gas plants become more economic than expected in the proforma case. If this becomes true, you would expect to see higher dispatch of our gas plants offset by lower net market purchases. The inverse is possible as well where market conditions are such that power plants are more expensive to operate than represented in the case. Varying hydro conditions can greatly affect our net purchases and sales as well.

Q. Is AURORA$_{XMP}$ representing this value?

A. Yes. By modeling 80 hydro years the model considers many possible futures and optimizes our resources under varying conditions. When hydro is low and market prices are higher, AURORA$_{XMP}$ generally dispatches non-hydro resources more aggressively and net market purchases are lower. When hydro is high and market prices are then lower, non-hydro generation resources generally dispatch less and net market purchases are higher. Different purchases and sales occur for each modeled water year of the proforma. I report the average of the 80 water year runs in my exhibits, while the details of each run are provided in working papers.

VI. Summary of Supplemental Testimony

Q. Please summarize the findings you have presented in this supplemental testimony.

A. The requested analysis by Staff serves to compare the results in this case to that presented in Avista's 2015 GRC. Staff asked for the major drivers of changes between the 2015 GRC and this case. Over 80 percent is due to a single, known and measurable event, e.g., the expiration of the Portland General Electric Exchange contract. As was discussed earlier in my testimony, Staff asked for the major drivers of changes between the 2015 GRC and this case. The analysis provided in this testimony (and supporting workpapers) provided support for 98.4 percent of the delta between this case and the 2015 GRC.

The ERM is highly dependent on natural gas prices and hydro conditions, both of which have been generally favorable in the past few years and have led to ERM deferrals in the rebate direction. Cumulatively, however, over the life of the ERM (since 2003), the balance is $37 million in the surcharge direction, even after taking into account recent deferrals in the rebate direction.

Q. Does this conclude your Supplemental Direct Testimony?

A. Yes, it does.