Exh. CGK-1T

WUTC DOCKET: 190334
EXHIBIT: CGK-1T
ADMIT ☑ W/D ☐ REJECT ☐

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET NO. UE-19______

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 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. Traditionally my testimony provided in general rate cases (GRCs) detailed power supply modeling and the associated costs being requested in each. In our 2017 GRC, Dockets UE-170485 and UG-170486, the Commission stated in their Final Order 07 that baseline adjustments to power supply costs should only be made "in extraordinary circumstances." More specifically, the Commission stated:[1]

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

Given that the Commission made its findings in Order 07 just last April 2018, and given that there have not been any extraordinary circumstances since that time as it relates to the our power supply portfolio and operations, the Company is not proposing to adjust its power supply base in this GRC. Rather, my testimony provides an update on the progress of the power supply modeling review effort being conducted at the Commission's direction:[2]

[1] Dockets UE-170485 and UG-170486, Order 07, ¶160.
[2] Per paragraph 161 in Commission Order in UE-170485, Order 7, beginning on page 55

> "… 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. … 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."

In summary, the Parties have engaged in multiple workshops but have not reached a conclusion on how best to approach modeling for future rate filings; however, very good progress has occurred since the workshops began in mid-2018 and Avista is hopeful consensus will be reached in 2019.

Q. Who are the Parties participating in this process?

A. The Parties include Commission Staff (Staff), Public Counsel (PC), and Alliance of Western Energy Consumers (AWEC), in addition to the Company. Invitations were sent out to all participating parties in the 2017 GRC.[3]

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. Pages 1 through 85 of Exh. CGK-2 are copies of workshop agendas and materials. Beginning on page 86 of Exh. CGK-2 is a Hydro Forecasting presentation provided to Commission Staff during their on-site visit on March 28, 2019. That information contained will be reviewed with the Parties at an upcoming workshop. A table of contents for my testimony is as follows:

[3] Parties to the 2017 Washington general rate case (Docket UE-170485) included the Commission's Regulatory Staff, Public Counsel, the Industrial Customers of Northwest Utilities (ICNU) and the Northwest Industrial Gas Users (NWIGU) - now combined as AWEC, and The Energy Project.

II. OVERVIEW OF WORKSHOPS

Q. Please provide an overview of the power supply modeling workshops the Company has held with stakeholders.

A. To date, four workshops have been held. The first two were held on June 13, 2018 and August 1, 2018 at the offices of PC in Tumwater, Washington. A third workshop was held on December 13, 2018 at PC offices in Olympia, Washington. Finally, on March 4, 2019, the Parties held the fourth workshop, at PC offices in Tumwater. A fifth workshop presently is scheduled for May 1, 2019 at PC offices in Olympia. Exhibit CGK-2 contains agendas from each meeting.

Q. Have the Parties participated in each workshop?

A. Yes, all of the Parties have participated in each workshop.

Q. Please provide a brief summary of the topics covered at each workshop.

A. The June 13, 2018 "Workshop 1" reviewed Commission language requiring the workshop and identified expectations of the Parties. We discussed a general schedule and the topics future workshops should cover, among other things. We discussed if/when modeling expert should be engaged, but no decisions were made to engage them at that time.

The August 1, 2018 "Workshop 2" described how Avista modifies the "out of the box" AURORA database and model settings when preparing its integrated resource plan ("IRP") and rate filings before the Idaho and Washington commissions. Our process to take power supply model results and translate them into retail rates also was discussed, including the various power supply adjustments not modeled in the AURORA power supply model directly.[4] The Parties again discussed when and whether to engage a 3rd party consultant to assist with the power supply modeling discussion but the consensus was that it was not necessary at that time. Finally, and importantly, the Parties identified a large body of analyses the Company ultimately completed over the next 3 months to help illustrate various aspects of power supply modeling and the sensitivity of the portfolio to varying assumptions.

Our December 13, "2018 Workshop 3" primarily covered the results of studies defined at Workshop 2, much of which is discussed below and the Company proposed a power supply modeling methodology very similar to what PAC has utilized in recent rate filings based on the study results. Stakeholders were asked to provide comments on the proposal.

"Workshop 4" was held on March 4, 2019. The key topic areas covered were an in-depth overview of our short- to long-term power planning, hedging and trading methodologies implemented to manage power supply cost risk, presentation of some additional power supply modeling results as a follow-up to Workshop 3, and a new Company-defined "strawman" power supply modeling proposal based on feedback from Staff. The strawman was offered to learn if enough consensus between the Parties then existed to begin finalizing a methodology for use in the next GRC where power supply expenses changed enough to warrant such effort.

[4] AURORA models only the dispatch value of Avista's resources and contracts and fuel. It does not account for various other expenses affecting our request, including, but not limited to, our contracts with Mid-Columbia parties, WNP-3, and Colstrip fuel.

Q. Have the Parties reached agreement on a new power supply modeling methodology after four workshops?

A. No. While very good progress has been made, reaching a full understanding among the Parties of the complexities of power supply modeling, and an agreement on a new power supply modeling methodology, will require more time.

Q. Has the work related to these issues only been conducted in the four workshops?

A. No. Prior to the first workshop, and ever since, the Parties have engaged in extensive informal discovery. While we have not formally logged each interaction, we have had dozens of phone calls and corresponded through a similar number of emails with one or more of the Parties, including as late as the drafting of this testimony. I, for one, have appreciated the engagement of all Parties to this process and expect the results and findings to strengthen our power supply models and methodologies going forward.

III. WORKSHOP FINDINGS

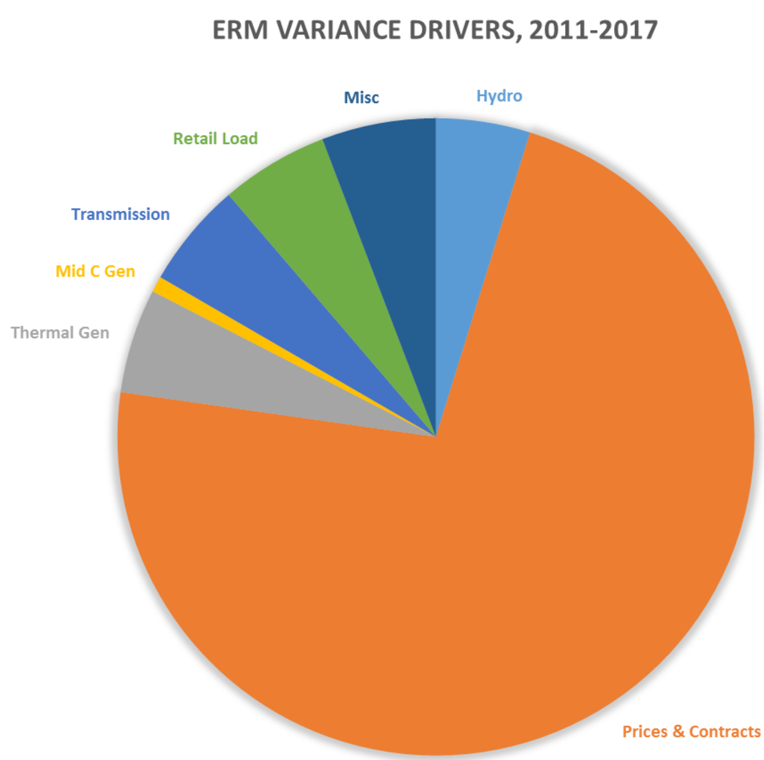
Q. What information about the PacifiCorp (PAC) and Puget Sound Energy (PSE) methodologies was presented in Workshop 2?

A. More details regarding Workshop 2 are provided in Exhibit CGK-2. To summarize, Avista described that PSE performs fewer adjustments to the AURORA model than does Avista. In fact, the PSE approach was termed by the workshop group as an "out-of-the-box" methodology. A more detailed description of the PSE method is described later in testimony. The PAC method was termed as a "Closed System" model, because unlike the Company and PSE's methods, their dispatch model, GRID, takes as inputs *both* natural gas and electricity prices. Instead of generating electricity prices and dispatching portfolio resources as AURORA does, GRID dispatches PAC resources against prices input into the model.

Q. What information about the Company's ERM history was shared at Workshop 2?

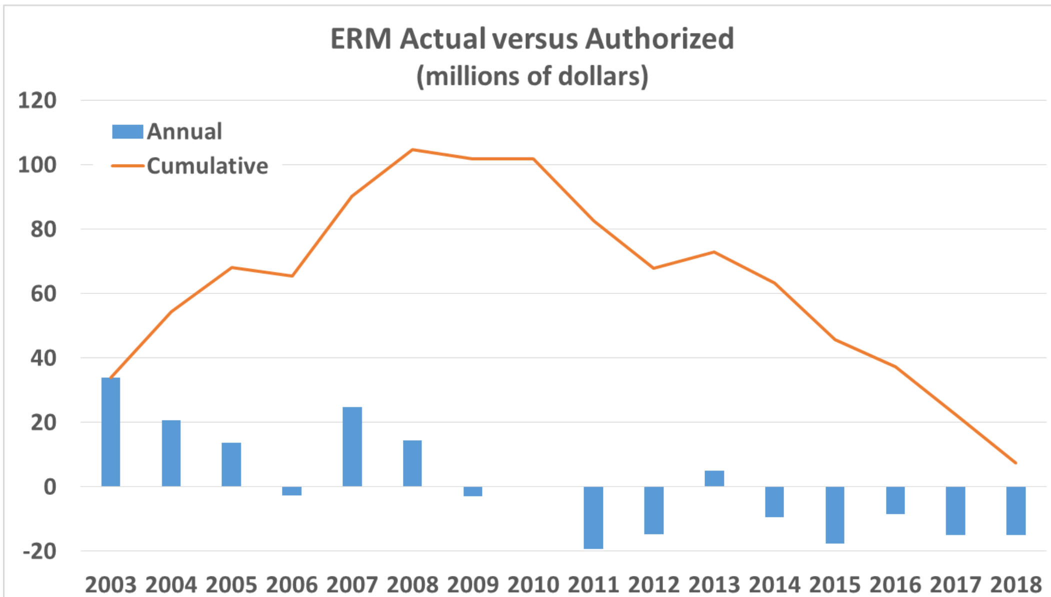
A. At Workshop 2, Avista presented a history of ERM balances, as well as the drivers for annual variances from authorized. Chart 1 below details the drivers of ERM variances, showing that the largest component, nearly 75 percent, is price and its impact on our purchases and sales. Variation is also explained by hydro variability, load, thermal generation and transmission revenues.

<u>Chart 1: Sources of Energy Recovery Mechanism Variance</u>



The workshop participants also were shown the ERM history through 2016. An updated version of that information to include calendar years 2017 and 2018 is presented in Chart 2 below.

<u>Chart 2: ERM History</u>



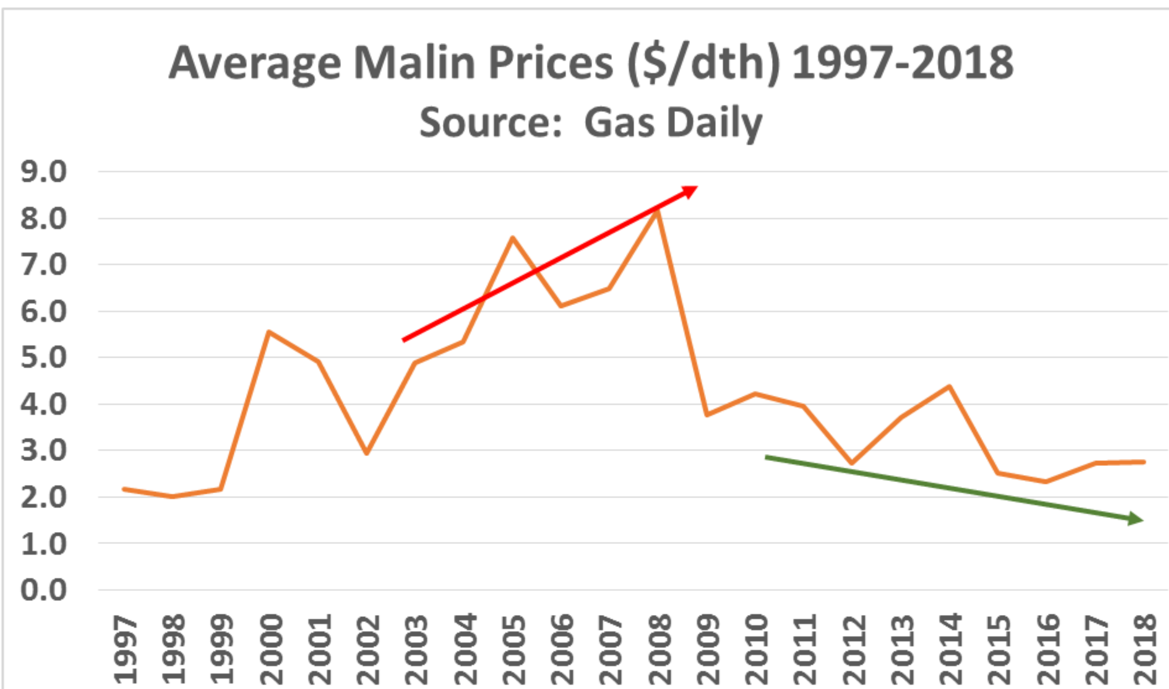
Q. Please explain Chart 2 shown above.

A. The chart shows that in early years through 2009, the Company absorbed on a cumulative basis, more than $100 million in costs not recovered from customers through the ERM. Actual costs in those years were much higher than the level of power supply and other costs tracked in the ERM authorized by the Commission. After 2011, with the exception of 2013, actual costs were lower than authorized. Through the end of 2018, the ERM cumulative balance since inception has nearly returned to zero. Throughout this entire period, the basic modeling parameters have remained largely unchanged.

Q. What were the conditions that led the Company to absorb higher costs through 2009, and then benefit after 2010?

A. In general we have learned that ERM balances are driven heavily by market conditions—conditions outside of the Company's control. As Chart 1 showed, approximately 75 percent of ERM variance is explained by market price movement and its impacts on our forward contracts for electricity and natural gas. In early years of the ERM, natural gas, and therefore electricity prices, were rising quickly. Actual prices ended up being higher than were forecast in GRCs. The opposite has occurred since 2010, with the general direction being falling wholesale natural gas and electricity prices, relative to authorized levels. Market pricing beyond our control explained most of the variances over time. Chart 3 below demonstrates this trend.

<u>Chart 3: Natural Gas Prices History</u>



Q. Does the Company have any general observations about natural gas prices and ERM balances that should inform our view of the future?

A. Yes. For many years now we have experienced falling natural gas prices as shown in Chart No. 3 above. This trend has created an artificial cushion, providing a false sense of security against what would otherwise be higher proforma costs. But in seeing recent history, it is important to not forget the lesson demonstrated by early ERM years: rising natural gas and electricity prices lead to ERM balance deficits, with the Company absorbing costs that exceeded $100 million. Having been the lead witness on power supply modeling through the entire ERM period, allows me to testify that our modeling since 2003 has not changed in ways material enough to offset the powerful impact of price volatility.

Just as in 2002, natural gas prices in recent years have been quite low when viewed against history. Market analysts and our traders talk about prices "having nowhere to go but up." I believe that ERM balances will reverse from their recent historical course of being in the rebate direction and will trend towards the surcharge direction when market prices rise. For example, the Company in late 2018 was forecasting a 2019 rebate deferral balance in the ERM of approximately $12 million. Given colder than normal weather that the whole Northwest region experienced in February 2019, and elevated natural gas prices due to high demand and pipeline restrictions, in just this one month the projected rebate balance fell to less than $5 million. We must be careful to recognize the true drivers of the ERM mechanism surpluses and deficits, and act with the perspective of history when judging its value.

Q. Do you view that recent experience as being "extraordinary"?

A. No, I do not. Wholesale natural gas and electricity prices are volatile – they always have been and always will be. For 2019, while the recent forecast shows deferrals in the rebate direction (which some may view as the Company unnecessarily benefitting from), volatility can quickly wipe away any benefit and drive the ERM into the surcharge direction. That is normal in my view, and the ERM appropriately tracks this volatility.

Q. You explained earlier that the workshop participants defined a body of studies the Company performed and presented in Workshop 3. What were these studies?

A. During discussions it became evident workshop participants wanted to know more about how various methods and data might affect overall modeled power supply expenses; and if some of the discrepancies between modeled and actual costs could be explained by these different methods and data. Because 2017 calendar year results were available at the time, it was agreed that the basis for our studies would be our 2016 general rate case filing containing pro forma expenses for 2017. The benefit of using this filing meant that key model input variables, namely market and fuel prices and hydro conditions, were known and could be compared to both the estimates from that time and actual Company results. The workshop identified six study cases, for comparison to 2017 actual costs (“2017 Actuals”):

- 2016 GRC Case
- Median Water
- Out-Of-The-Box
- Closed System – Median Water
- Closed System – 80-Year Water
- Closed System – Backcast

Q. Please provide a brief description of each modeling case.

A. First, “2017 Actuals” is a frame of reference for each of the other cases. In other words, the goal of each modeled case was to determine how closely it reflected 2017 actuals.

The “2016 GRC Case” represents 2017 costs Avista filed in UE-160228 and presents anticipated 2017 costs for that case. Similar to the 2017 Actuals case, it provides a reference point for comparison of new modeling methods and data. The “Median Water” case explains the difference between the costs filed in the 2016 GRC and where the Company modeled costs based only on a median water year, rather than averaging of the 80 water years used in the previous GRC. The “Out-Of-The-Box” case substantially emulates how PSE prepares its filings. Unlike Avista, PSE makes very few adjustments to the AURORA power supply model when estimating costs. The only large changes are updates to AURORA’s database reflecting the Company’s portfolio of resources and contracts, natural gas and Colstrip fuel prices, and the 80-year BPA hydro record.

Rather than using AURORA to model power supply expenses, PAC uses its proprietary GRID model. I define this approach as a “Closed System,” in that market prices for natural gas and electricity are input and GRID dispatches PAC resources to those prices. This differs from Avista and PSE’s methods of modeling power supply expenses, where AURORA dispatches utility resources <u>and</u> develops the market electricity prices our resources are dispatched against in each hour of the pro forma period.

Three Closed System cases were evaluated. For comparison purposes to existing modeling method, “Closed System – Median Water” and “Closed System – 80-Year Water” were run. The third case, “Closed System – Backcast”, was a backcast using <u>actual</u>

<u>experienced conditions</u>, including: 2017 hydro, fuel and market prices, forced outage and maintenance schedules, and power and natural gas term transactions. The purpose of the Closed System – Backcast case was to evaluate if inputs to the model (i.e., forecast assumptions) or the model itself was the reason for the discrepancy between pro forma and actual costs.

Q. What were the key learnings from the case studies?

A. At the December 13, 2018 workshop, Avista presented a number of summary points and conclusions. First, when using the same input variables (i.e., market price, hydro conditions, etc.) the various methods arrived at similar power cost estimates. This can be best explained in Chart 4 below, presented at that workshop.

<u>Chart 4: Workshop-Modeled Power Supply Costs</u>

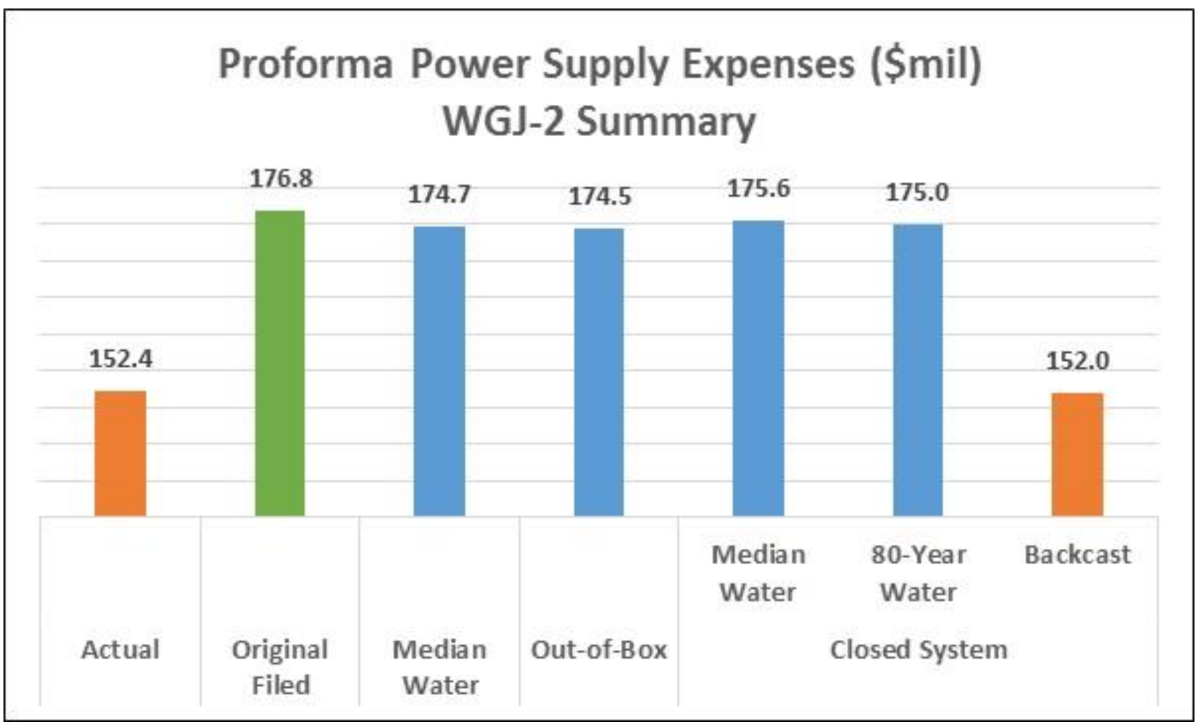


Chart 4 shows that power supply modeling, using the same input assumptions as were available in the 2016 GRC, arrived at substantially the same answer (approximately $175 million in Power Supply expenses). This can be seen by comparing the 2016 GRC "Original Filed" case (presented in green) with the other evaluated methods shown in blue.

The chart also illustrates how using actual market prices, hydro and other data, unknown to modelers at the time of a rate filing, arrived at a nearly perfect result—0.3% difference, or $400,000, on more than $150 million in actual costs.

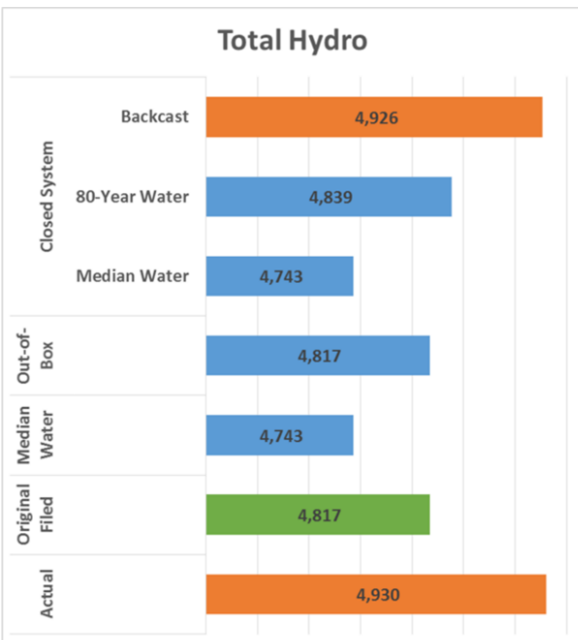
Second, all of the alternative modeling methods are simpler to run and audit than the method Avista currently uses. There are fewer adjustments made for Staff and other intervenors to audit, and in the end arrived at a substantially similar result. At a minimum, it is clear to the Company that we can simplify our modeling, providing benefits not only to Avista in terms of simplified modeling, but also benefitting Commission Staff and other intervening Parties in their review of future-filed power supply adjustments, if we simply used an "out of the box" (PSE) method.

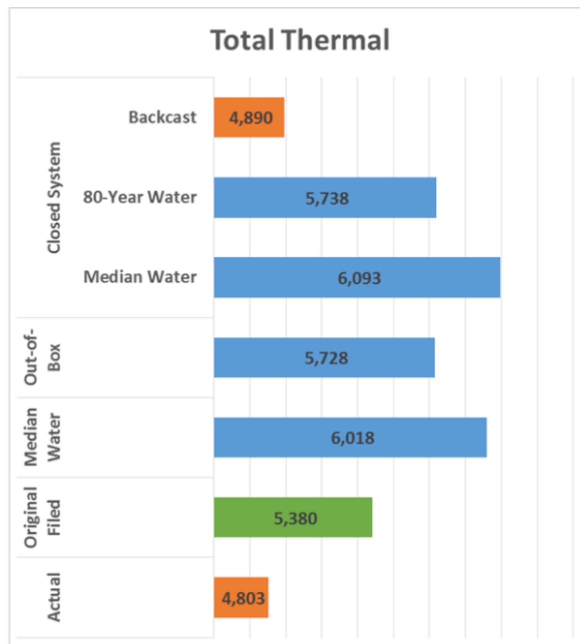
Third, and because the backcast provided such a close approximation of actuals, forecast error appears to be what drives variance. In other words, because we cannot predict future hydro and price conditions accurately, modeled power supply costs will continue to diverge from actuals, and in both directions, depending on how closely actual data compares to forecast data included in the ERM baseline. As a final note, the "backcast" figure shown in the last column, simply states the obvious: if we had perfect foresight, out modeling would have replicated actual 2017 results.

Q. Are there other comparisons that illustrate how, where prices and hydro conditions are known more precisely, power modeling is being performed well?

A. Yes. Chart 5 shows how modeled hydro and generation levels are very similar once actual prices are known. Generation levels vary across cases, but in the Actual and Backcast cases generation levels are almost the same. Further, even across the cases where prices are being forecast, represented in blue (alternative modeling methods) and green (2016 GRC filed case), generation levels are not significantly different.

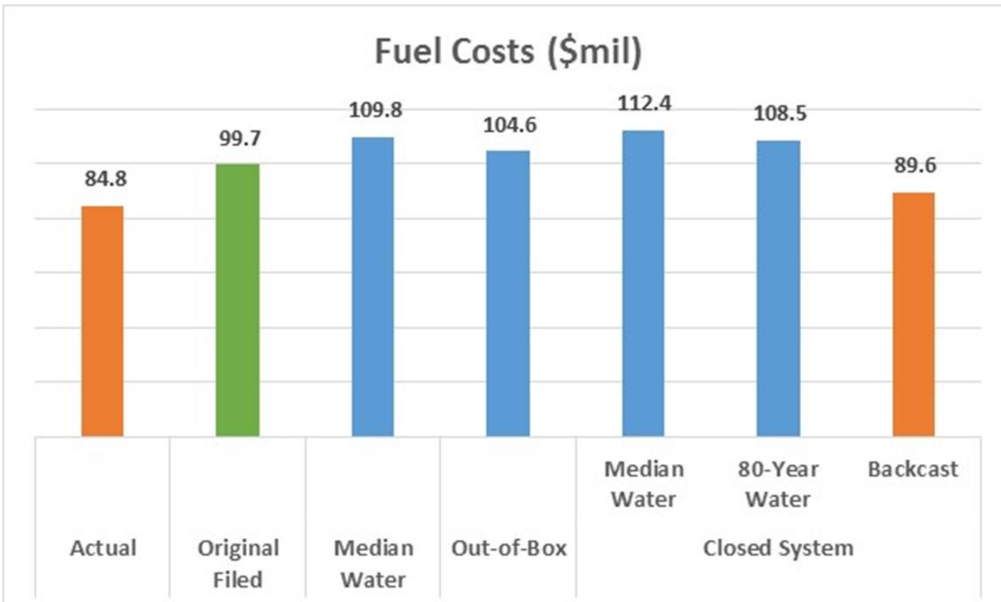
<u>Chart 5: Modeled Hydro and Thermal Output</u>





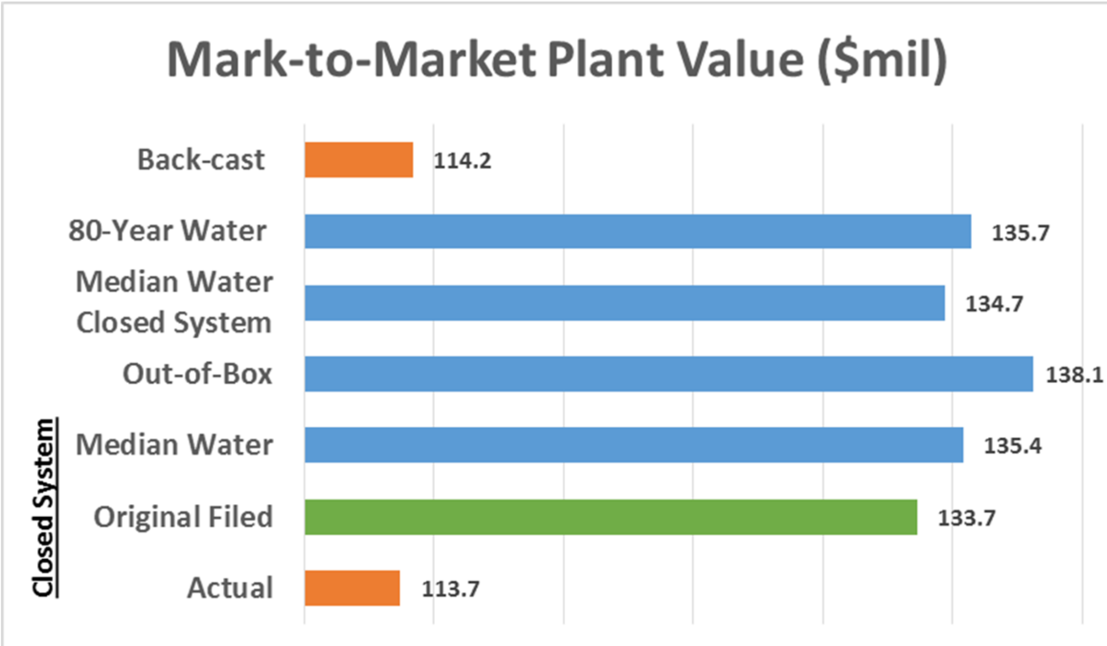
The same can be said for fuel costs. While the discrepancy in fuel costs on a percentage basis is higher than for absolute generation levels, as shown in Chart 6 below, the Backcast and Actual 2017 cases (see orange bars) are not all that dissimilar.

Chart 6: Modeled Fuel Costs ($millions)



Finally, mark-to-market comparisons of power supply modeling illustrate how closely power supply modeling can emulate actual conditions where hydro and price forecasting errors are eliminated. Mark-to-market is the value of a power plant, or portfolio of power plants, after paying its fuel and variable operation and maintenance costs. The modeled value of our overall generation portfolio is almost identical once prices and hydro volumes are known, at approximately $114 million, as shown in Chart 7. Unfortunately, hydro and prices cannot be forecast with any great level of precision so we can expect continued variances to drive noticeable ERM values in both rebate and deficit directions.

Chart 7: Resource Portfolio Mark-To-Market Valuation ($millions)



Q. Why do you say you cannot predict hydro conditions more accurately?

A. We use hydro estimates for short-term operations based on national forecasting services, but the correlation of available information, such as snow pack or snow water equivalent, to actual river runoff is extremely poor until you get within a month or two of the actual run-off period. It depends on many factors that change quickly – e.g., levels of spring run-off, temperatures, rainfall, etc. These forecasts are therefore not useful in a GRC proceeding.

The Company is not aware of a better method to predict rate period hydro conditions. First it is important to understand that hydro projections are being made between 12 and 18 months ahead of when actual river flows will be experienced. There simply is no information available this far ahead to indicate what hydro conditions will occur during the rate period.

Therefore Avista and this Commission have for decades supported using average hydro runoff conditions to set base rates, estimated by using the entire hydro record.

Q. You demonstrated in Chart 1 that market prices, and the impact of the market on power purchase and sale contracts, represent three-quarters of ERM variance. Why can forward prices not be forecasted with more accuracy?

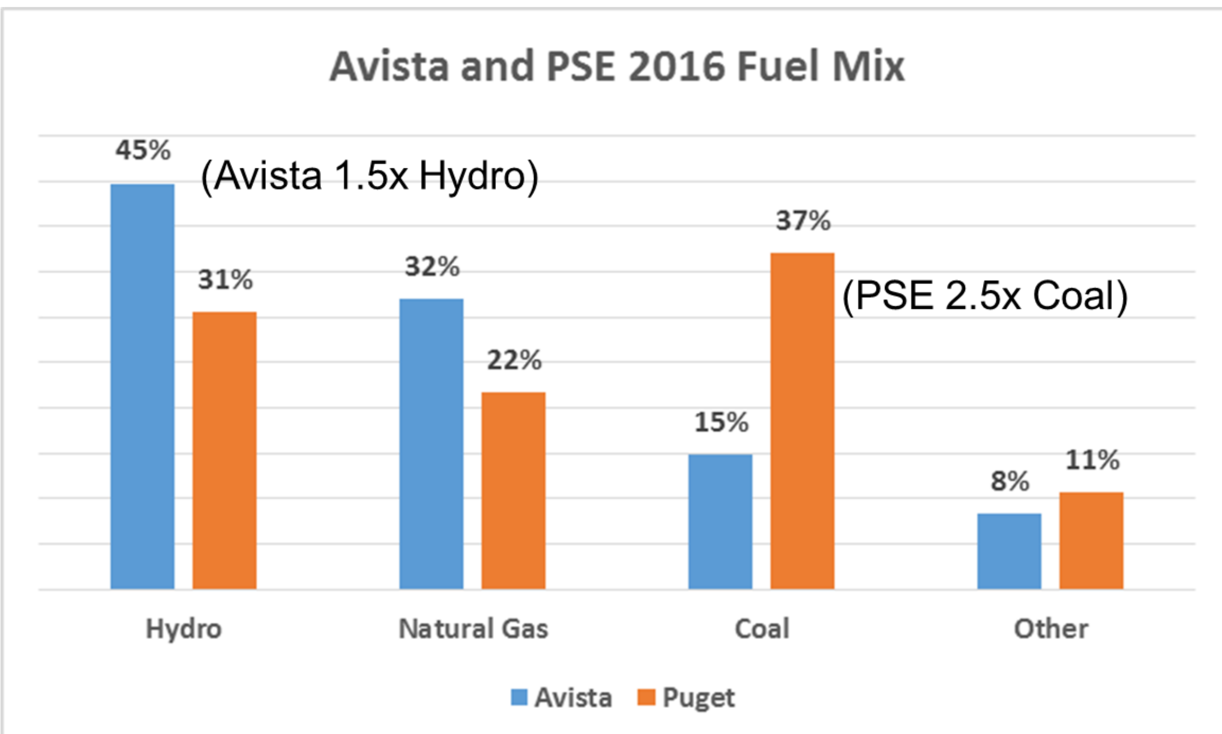
A. It is important to remember the age-old adage, "if one could forecast prices accurately, they wouldn't be working here." This adage isn't shared to be flippant, but to remind everyone in this proceeding that predicting prices is one of the most difficult things to do in our industry. Complicated algorithms, Monte Carlo analysis, etc. are among the many imperfect tools that understandably never get it right. This holds true in many industries. Electricity and natural gas prices are among the most volatile commodities traded in the United States, and especially in the Northwest, which is so heavily influenced by hydro generation. Unfortunately, this volatility is reflected in our power supply expenses and drives most of our ERM variance.

In an attempt to lessen the volatility created by market-price variance, the ERM provides a deadband whereby the Company absorbs significant volatility. The Company also follows a hedging program to avoid exposing customers to the whims of the spot market. The present method of estimating GRC power supply costs based on a long-adopted hydro averaging method, combined with matching prices to then-current forward prices, provides a reasonable estimate. While many Parties, including the Company and the Commission, are understandably disappointed that GRC estimates can be greatly different from what is actually experienced, no party thus far has identified a superior method to what is being used today. The workshop analyses also have not identified a superior method. In fact, the backcasting efforts have shown that when using actual market conditions, including hydro runoff, the power supply model does an exceptional job of approximating actual costs.

Q. You suggest that prices and hydro cannot be predicted with more certainty. Why does PSE have less volatility in its PCA relative to the Company's ERM?

A. Relative to load, Avista has 150 percent of the hydro PSE has. This exposes us to significantly <u>more</u> price *and* volatility risk, because we cannot predict runoff (water is the fuel, not coal or natural gas). PSE also meets 2.5 times as much load with coal as Avista does. Unlike hydro and natural gas resources serving a much higher share of Company loads, coal is both low cost and benefits from fixed and known fuel costs and volumes. In total, <u>PSE's portfolio should be expected to be less volatile</u>. Both of these differences are demonstrated in Chart 8.

<u>Chart 8: Company and PSE Fuel Mixes</u>



Finally, the base for PSE's PCA is *all* power supply costs, including fixed and variable operations and maintenance costs and the cost of capital associated with recovery of those costs; approximately forty percent of its PCA costs in 2016 were of a <u>fixed</u> nature. The Company's ERM <u>includes only variable costs</u>, meaning the base over which variability occurs is forty percent smaller and the resulting variation year-to-year on a percentage basis appears greater. Given the large difference in the make-up of our resource mix and the included components of our recovery mechanism, it is not appropriate to use PSE's PCA to benchmark our ERM.

Q. Are PSE's less volatile results likely due to better price and hydro forecasting?

A. Almost certainly not. In researching how PSE performs its GRC power supply cost estimation I learned that it uses a similar hydro representation in its rate filings and has no better methodology for predicting future prices. I believe the major driver of less volatility, as explained above, is PSE's significantly lower reliance on hydro and natural gas-fired generation and the inclusion of fixed cost components in its PCA.

Q. You mentioned above that Workshop 4 contained additional modeling results. Please describe this information.

A. For Workshop 3 the Company presented a backcast using the PAC "Closed System" methodology. The effort demonstrated that using actual 2017 input assumptions (e.g., hydro conditions, market prices) resulted in a very close approximation of costs experienced by the Company ($152.0 million modeled vs. $152.4 million actual, or -0.26%). In discussions following Workshop 3, including feedback from Staff, it was the Company's interpretation that the Parties were leaning toward using the PSE "out-of-the-box" methodology. To this end the Company ran another backcast using the PSE "out-of-the-box" methodology for presentation at Workshop 4. While not quite as precise, the results demonstrated that for 2017 the PSE methodology backcast provided good but less accurate results than the PAC "Closed System" methodology ($159.0 million modeled vs. $152.4 million actual, or +5.64%). The results were much better than the $176.8 million figure (+16.01%) filed in the 2016 case.

IV. NEXT STEPS

Q. You share above that the Parties have not reached consensus on power supply modeling for the Company's next GRC containing power supply adjustments. Have the Parties continued working to achieve agreement?

A. Yes. Our next workshop, Workshop 5, is scheduled for May 1, 2019. While the final agenda for this meeting is not set, it will contain a new analysis requested after Workshop 4 by PC. Namely, PC asked to understand how updating power supply modeling input assumptions (e.g., natural gas prices, forward power and natural gas contract purchases) at the end of the 2016 GRC might bring authorized costs closer to what were actually experienced.

Finally, Commission Staff visited Company headquarters in Spokane on March 29, 2019, where they visited our trading floor to learn more about how power trading occurs in our business, to learn about inputs and outputs of the daily position report and how it factors into our decision making, to interview our hydro engineers and learn more about how we use hydro forecasting to manage power supply costs, and visited with our AURORA modelers to learn more about the various methods we employ to forecast normalized future conditions.

The Company felt the on-site visit was especially valuable and appreciate the efforts of Staff to visit our offices. It is the Company's intent to host additional on-site technical workshops with other stakeholders to allow a deeper discussion and provide a better understanding of the Company's entire power supply operations.

Each of these ongoing efforts demonstrate commitment by the Parties to achieve consensus on an improved power supply modeling methodology and we appreciate that.

Q. Earlier in your testimony you indicated that further workshops will be necessary to achieve consensus. Do you have an expectation on when the Parties might reach such consensus?

A. I do not have an estimate. Given the complexities identified, my opinion is that consensus after Workshop 5 in May of this year is not likely. At least one or two more workshops will be required. General discovery still is ongoing. Once this aspect is complete, the Parties will need to reach consensus on a new methodology. While Avista has consulted with our peer utilities, as ordered by the Commission, should the Parties desire additional information from our peer utilities, we may ask them to participate in an upcoming workshop. The hiring of a power supply consultant, as described in Order 7, may still be required to help the Parties achieve consensus. A consultant review surely will not be a quick exercise. All of this said, we have the time needed to achieve our goals, namely simplification and improved modeling accuracy. The Company believes we can achieve these goals with active participation, and ultimately agreement, of the Parties to ensure our next GRC containing power supply adjustments relies on a model and associated methodologies and data all Parties can support.

Q. You mentioned above that Staff visited your headquarters for a technical meeting. Will a similar offering to all Parties be made?

A. Yes. The Spokane visit was an excellent opportunity for Staff to visit with our Power Supply experts and obtain first-hand information about how we manage our power supply expenses. Building on the success of this meeting, we believe offering a similar opportunity to all workshop participants will be beneficial.

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

A. Yes, it does.