Exh. CSH-1T
Dockets UE-170485/UG-170486
Witness: Christopher S. Hancock

BEFORE THE WASHINGTON
STATE UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **AVISTA CORPORATION d/b/a AVISTA UTILITIES,** **Respondent.**	**DOCKETS UE-170485 and UG-170486 (*Consolidated*)**

TESTIMONY OF

Christopher S. Hancock

STAFF OF
WASHINGTON UTILITIES AND
TRANSPORTATION COMMISSION

Policy; Multi-year Rate Plan; Electric Adjustment 3.15 and Natural Gas Adjustment 3.14

October 27, 2017

TABLE OF CONTENTS

LIST OF EXHIBITS

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Christopher Scott Hancock. My business address is The Richard Hemstad Building, 1300 S. Evergreen Park Drive S.W., Olympia, WA 98504.

Q. By whom are you employed and in what capacity?

A. I am employed by the Washington Utilities and Transportation Commission (Commission) as a Regulatory Analyst in the Energy Regulation Section of the Regulatory Services Division.

Q. How long have you been employed by the Commission?

A. I have been employed by the Commission since January 2015.

Q. Would you please state your educational and professional background?

A. I graduated from New Mexico State University in 2013 with a Bachelor of Business Administration degree in Economics. In 2014, I graduated from New Mexico State University with a Master of Arts degree in Economics, specializing in Public Utility Policy & Regulation. Prior to my employment with the Commission, I interned at Southern California Edison's regulatory affairs department, and served six years in the United States Air Force before being honorably discharged.

Q. Have you previously testified before the Commission?

A. Yes. I have most recently testified as Staff's witness on funding mechanisms for the decommissioning and remediation of Colstrip Units 1 and 2, and on payment processing cost adjustments, in Dockets UE-170033 and UG-170034. I have also been Staff's attrition study witness in Dockets UE-160228 and UG-160229. I also have testified on traditional modified historical test years and pro forma capital additions in Dockets UE-150204 and UG-150205, and served as Staff's witness on cost of service, rate spread, rate design, and decoupling in Docket UG-152286, a settled general rate case for Cascade Natural Gas.

II. SCOPE OF TESTIMONY

Q. What is the purpose of your testimony?

A. I provide Staff's policy testimony in this case, covering topics that include end-of-period accounting for the test year, regulatory lag, and multi-year rate plans.

I am responsible for Adjustment 3.15 in Staff's electric revenue requirement model, and Adjustment 3.14 in Staff's natural gas revenue requirement model, for the first year of rates. I also sponsor Staff's multi-year rate plan revenue requirement models.

Q. Have you prepared any exhibits in support of your testimony?

A. Yes. I prepared Exh. CSH-2 and Exh. CSH-3. These exhibits present the calculation of revenues for the second and third years of Staff's proposed rate plan, for electric and natural gas, respectively.

Second, I sponsor Exh. CSH-4, which illustrates the composition and calculation of Staff's composite revenue escalator.

Third, I sponsor Exh. CSH-5 and Exh. CSH-6. These exhibits show the historical growth rate of the four escalation components, using linear regression.

Q. Please summarize Staff's recommendations on a multi-year rate plan.

A. Staff recommends a multi-year rate plan, so as to break the current cycle of almost continuous rate cases from Avista. The rate plan is constructed in a manner that recognizes the benefits of regulatory lag. The rate plan defers ruling on the prudency of capital additions until Avista's next rate case, where Avista will be expected to fully support the capital additions made during the rate plan.

Q. How is the remainder of your testimony organized?

A. In Section III, I introduce other witnesses testifying on behalf of Staff. In Section IV, I discuss policy matters relevant to this case. In Section V, I discuss the company's purported end-of-period rate base adjustment. In Section VI, I provide commentary on Avista's rate plan. In Section VII, I describe Staff's rate plan and highlight its merits. Finally, in Section VIII, I briefly review the estimates of select parties from the 2015 Avista rate case.

III. INTRODUCTION OF STAFF WITNESSES

Q. Please introduce Staff's witnesses.

A. The following witnesses present testimony and exhibits on behalf of Staff:

- Mr. David Gomez presents Staff's analysis of power supply expense.
- Ms. Elizabeth O'Connell presents Staff's recommendations for cost of service, rate spread, and rate design for both electric and natural gas service.
- Ms. Kathi Scanlan presents a review of the Commission's modified historical test year ratemaking practice, pro forma policy, and Staff's application of those Commission standards to Avista's rate base adjustments in this case.
- Ms. Betty Erdahl presents Staff's calculation of investor-supplied working capital.
- Ms. Joanna Huang presents Staff's revenue requirement model for the first year of rates, as well as other specific adjustments to that model.
- Mr. Chris McGuire presents Staff's position on interest rate hedging losses.
- Mr. David Parcell presents Staff's position on cost of capital.
- Ms. Jennifer Snyder provides Staff's review of the Line Extension Allowance Program, and its recommendation on Avista's fuel conversion program.

- Ms. Amy White provides Staff's review of property tax adjustments and uncollectibles expense.

IV. POLICY DISCUSSION

Q. What policy matters will you discuss?

A. I will provide a review of the purpose and rationale for multi-year rate plans, as well as a description of their mechanics. I will provide commentary on regulatory lag. Finally, I will provide recommendations on low income and gas conservation issues.

Q. What methodology does the Commission typically use to set rates?

A. The Commission typically uses a modified historical test year (MHTY), with limited pro forma adjustments.

Q. Is Avista's filing consistent with a MHTY with limited pro forma adjustments?

A. Avista's filing uses a modified historical test year, although the pro forma adjustments can hardly be said to be limited. Avista refers to its modified historical test year filing as an "EOP Rate Base Study," and uses this study to establish revenues for the first year of new rates. This matter is further discussed in Section V of this testimony.

Q. Does Avista seek extraordinary ratemaking treatment in this rate case?

A. Yes. Staff identified the following requests from the company as being extraordinary:

1. Use of end-of-period (EOP) accounting for the test year;
2. Indiscriminate use of pro forma rate base additions a for an entire year beyond the test year;
3. A hypothetical capital structure; and
4. A multi-year rate plan using a "K-factor."

Q. What do you mean by "extraordinary ratemaking treatment?"

A. Staff uses this term to refer to the "tools . . . proposed for use in a given case" that "must be chosen with specific reference to the needs of the case."[1] These tools do not necessarily require a finding of extraordinary circumstances.

A. Discussion on regulatory lag, and attrition

Q. What is regulatory lag?

A. Regulatory lag is "the inevitable delay that regulation imposes in the downward adjustment of rate levels that produce excessive rates of return and in the upwards adjustments ordinarily called for if profits are too low."[2] In other words, regulatory lag is the period of time that occurs between the time in which a cost to a utility

[1] *Wash. Utils. & Transp. Comm'n v. Avista Corp., d/b/a Avista Utilities*, Dockets UE-160228 and UG-160229, Order 06, Final Order Rejecting Tariff Filing, 49, ¶ 82 (Dec. 15, 2016).
[2] Alfred Kahn, *The Economics of Regulation: Principles and Institutions*, Vol. II, p. 48 (1988).

changes, and the time when that change is reflected in customer rates. Costs that the utility incurs change; costs that the utility charges its customers stay fixed. This disconnect between the costs the utility faces, and the prices the utility charges its customers, can prove to be beneficial or harmful to the utility.

Regulatory lag exists for administrative reasons; it is an unavoidable business reality for a regulated utility and its regulator. Nonetheless, its incentivizing effects have been noted in regulatory literature for decades.

Q. Is regulatory lag good, or bad?

A. Regulatory lag is neither good nor bad. It can work to the benefit of customers, or to the benefit of the regulated utility. When average costs are increasing, regulatory lag works to the detriment of the utility. When average costs are decreasing, regulatory lag works to the benefit of the utility.

<u>Regulatory lag serves as an important tool for regulators and the public</u>. It is only when the costs that a utility incurs increase, *and* when those costs are unavoidable, *and* when those costs threaten a regulated utility's financial position that regulatory lag is "bad." At that point, regulatory lag causes attrition.

Q. What is attrition?

A. "Attrition" in the context of utility ratemaking refers to a scenario in which a utility's costs grow at a faster rate than the utility's revenues, thus eroding the regulated utility's opportunity to achieve a reasonable rate of return. Attrition is a phenomenon, or a condition; it is not a treatment.

Q. Does Staff recommend an "attrition adjustment" in this case?

A. No. To be clear, Staff's multi-year rate plan is not based on an attrition analysis and does not include any attrition adjustments.

Q. How should a regulator strike a balance with regulatory lag?

A. Generally, the more forward-looking a regulator is when setting a company's rates, the more the regulator should rely on regulatory lag as a tool to shape efficient behavior. The less forward-looking a regulator is when setting a company's rates, the more conscious the regulator should be of the potential detrimental effects of regulatory lag.

Q. What are some arguments against regulatory lag?

A. Regulatory lag, particularly from a utility's perspective, can pose a challenge. In jurisdictions that typically use historical test years (such as Washington), rates are established primarily on the basis of observed costs, rather than prospective costs. The premise behind this theory is that the cost relationships of the historical test year, will remain the same for the near-term future. That is, the relationships between costs, revenues and rate base will hold through the rate-effective period. Utilities worry that when new rates are established, those rates will not adequately reflect even current costs—that regulatory lag is already "baked in" to the new rates established by the commission. An example of this is when a capital project is added to rate base during the course of a general rate case, without being reflected in rate base in the commission's final order.

Some utilities also worry that the effects of regulatory lag are not countered by so-called "revenue-generating" capital expenditures, as was often the case in the past. Relatively flat load growth paired with rising costs for safety, reliability, environmental, and replacement investments cannot blunt the effects of regulatory lag, because they do not serve as new sources of revenue; these types of investment serve existing load, and existing revenue sources.

Q. What are arguments in support of regulatory lag?

A. The argument for regulatory lag is voiced less often and less forcefully than the argument against regulatory lag. However, it is equally deserving of hearing.

Regulatory lag imposes discipline on utility operations and investment decisions, thus encouraging efficiency. The late Professor Alfred Kahn, a noted expert on regulation, described regulatory lag as a "positive advantage" rather than a "deplorable imperfection of regulation."[3] He explained:

> Freezing rates for the period of the lag imposes penalties for inefficiency, excessive conservatism, and wrong guesses, and offers rewards for their opposites: companies can for a time keep the higher profits they reap from a superior performance and have to suffer the losses from a poor one. A similar function is served by the Commission's following the explicit policy of holding permitted profits not to a fixed percentage, but within a range or 'zone of reasonableness,' with adjustments in rates permitted or imposed only when returns fall outside that range.[4]

[3] Alfred Kahn, *The Economics of Regulation: Principles and Institutions*, Vol. II, p. 48 (1988).
[4] *Id*.

The careful reader will note that this is remarkably similar to a common justification presented for multi-year rate plans.[5] A multi-year rate plan necessarily involves the active engineering of regulatory lag.

Regulatory lag also serves as a disincentive to overcapitalization, or “gold-plating.” When a utility believes that it will experience (detrimental) regulatory lag, it is less likely to make unnecessarily large capital additions, as it will have to bear the costs of those capital additions for the period of the regulatory lag.

Finally, regulatory lag, combined with the threat of prudence disallowances, prevents utility regulation from devolving into a “cost-plus” approach. “Cost-plus” refers to a phenomenon where the costs of providing service, plus a return, are simply passed on to customers. Under such an approach, a utility’s actions are not only virtually risk-free, but they are also not constrained by a proxy for competitive market forces. Regulatory lag and the threat of disallowance serve as that proxy.

It is worth emphasizing that some companies benefit from regulatory lag; we can see this even in Washington State itself, in the example of NW Natural. Natural gas utilities like Puget Sound Energy, Avista, and Cascade Natural Gas have all individually made several rate case filings since NW Natural last submitted a filing.

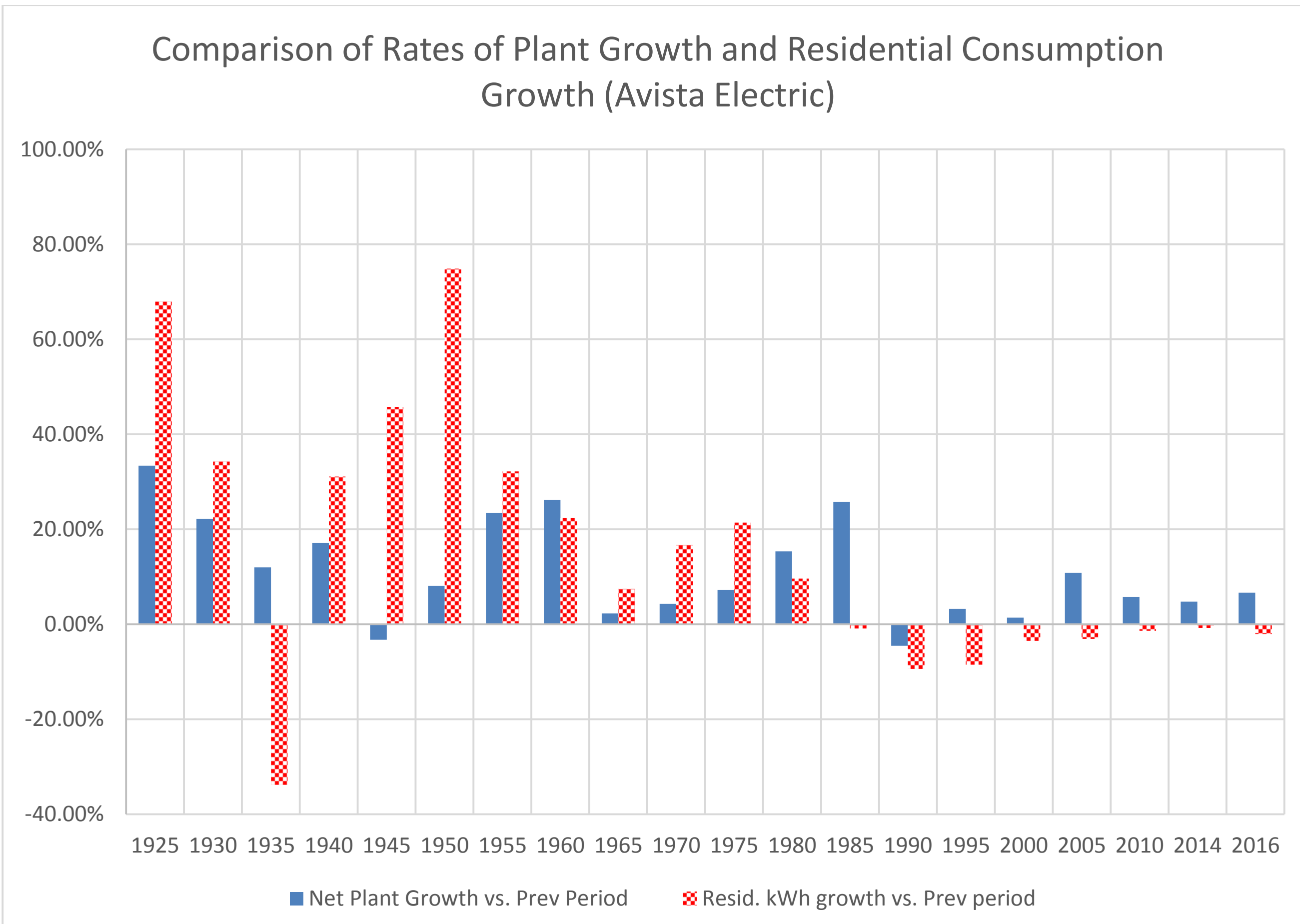
Q. Why did traditional cost of service regulation work so well in the past?

A. In the past, rising costs were largely attributable to growth in system capacity. Of course, growth in system capacity was driven by the expectation that usage would grow as well. Most utilities operated without decoupling mechanisms during this

[5] Although Avista does not explicitly make this argument, it is implicit in its support for an “efficiency adjustment.” *See* Andrews, Exh. EMA-1T at 31:8-14, and Andrews, Exh. EMA-4 at 17:15-17.

time; a company's revenues were dependent upon billing determinants like customer counts and throughput (kWhs or therms). As costs grew, revenues also grew. While these growth rates were not exactly the same, they were similar enough to one another to stave off the need for frequent rate cases.

This point is illustrated by comparing growth in Avista's net electric plant and growth in Avista's residential kilowatt-hours sold over time:



The data in the above graphic are drawn from the same data set as Illustrations 4 and 5 in the testimony of Scott Morris. Here we see that for significant portions of Avista's history (bar the Great Depression), growth in consumption (using residential kWhs as a proxy) outpaced the growth in plant. Avista is not unusual in this respect. This feature was particularly helpful for the company, as the price of kWhs included some portion of costs associated with fixed plant. Over the past 30 years, that has changed.

Q. What has changed?

A. Plant growth now outpaces growth in consumption (or load). In fact, residential load growth is declining.

On the plant growth side, this is due to the replacement of old plant with newer, more expensive plant, as well as new types of plant. On the consumption side, this is due to conservation measures, more efficient appliances, and changing customer preferences. There is a clear change, roughly around 1980, in the relationship between load growth and capital growth; the solid blue bars become taller than the patterned red and white bars.

Q. What are the causes of attrition?

A. There are numerous potential causes of attrition, which vary wildly. Causes of attrition can be sorted into two types: cost-based attrition and revenue-based attrition.

Some types of cost-based attrition are:

- Inflation of inputs (i.e., labor, fuel, etc.);
- Large capital expansion periods;
- Large increases in taxes;
- Poor management.

Some types of revenue-based attrition are:

- Flat or low load growth;
- Insufficiently set revenues.

Q. Does an MRP combat attrition?

A. Yes. In fact, this is one of the primary purposes of a multi-year rate plan.

B. Multi-year Rate Plans

Q. What is a multi-year rate plan (MRP)?

A. A multi-year rate plan is, as the name suggests, a ratemaking tool to provide for utility rates over the course of several years. It is almost always a plan to provide for increasing rates over the relevant period.

It can be helpful to think of a multi-year rate plan as a deliberate use of regulatory lag.

Q. What are some of the benefits of a multi-year rate plan?

A. Multi-year rate plans are attractive to utilities because they modify the timing and certainty of capital cost recovery for new investments. They are attractive to ratepayers because they provide for a gradual, predictable path for rate changes, and provide a meaningful incentive to utilities to strive towards cost-savings. Customers can benefit from those cost-saving measures either through an earnings sharing mechanism, or in subsequent rate case filings that are updated to reflect the efficiencies gained by the utility during the course of the rate plan.

For regulators, MRPs are attractive because they provide utilities with incentives to control their costs, provide for moderate rate changes, and provide utilities with flexibility in their operations. They also lower regulatory costs.

Finally, multi-year rate plans reduce the likelihood of continuous rate case filings, as we have seen in recent years with Avista.

Q. What problems are associated with frequent rate case filings?

A. Frequent rate cases impose costs on utility management, regulatory staff, and other intervening parties.[6] Frequent rate case filings weaken utility performance incentives. Multi-year rate plans act as an alternative by temporarily denying the company the ability to time rate case filings.[7]

Frequent rate case filings can approximate "cost-plus" ratemaking, a topic that is explored later in this testimony. So-called back-to-back filings, especially when paired with similar activity by other regulated utilities, also burden intervening parties, exhausting their resources and reducing their ability to effectively counter the asymmetric knowledge and resources of the utility. These parties are denied the opportunity to fully reflect on rate case outcomes and strategies, and find their ability to fully investigate other matters compromised. Those other matters are often other companies' rate case filings.

An example along these lines is in that in recent years, test year figures are hardly afforded the same degree of attention that pro forma adjustments are given.

---

[6] This was a major reason for approving PSE's multi-year rate plan in Dockets UE-130137 and UG-130138.
[7] *See* Ellen M. Pint, *Price-Cap versus Rate-of-Return Regulation in a Stochastic-Cost Model*, 23 RAND J. Econ. 564 (Winter 1992).

The reduced scrutiny given to test year figures is an important element in "cost-plus" regulation.

Q. What are the downsides to multi-year rate plans?

A. Rate plans require regulators to accept a small degree of uncertainty over the ongoing conditions facing the company during the rate-effective period. Because rate plans consider capital additions, operating expenses, and other matters of the utility that occur further into the future, there is a greater likelihood of estimation error. This estimation error can result in either a windfall or a revenue insufficiency for the company in question.

Utilities face risk in multi-year rate plans as well. If the revenues in the second and third year of a rate plan are calculated in a manner that proves to be insufficient, the utility faces a greater risk of falling short of its target rate of return. Or as the Commission recently stated in reference to PSE's multi-year rate plan in Dockets UE-130137 and UG-130138: "This approach requires the Company to accept some risk that rates in a future year will be sufficient, but it also provides more certainty to customers. It creates an incentive for the Company to control costs during the years that rates are in effect."[8]

[8] *Wash. Utils. & Transp. Comm'n v. Avista Corp. d/b/a Avista Utils.*, Dockets UE-150204 and UG-150205, Order 05, Final Order Rejecting Tariff Filing, Accepting Partial Settlement Stipulation, Authorizing Tariff Filings, 48, ¶ 130 (Jan. 6, 2016).

Q. How are multi-year rate plans typically justified?

A. A report by the National Regulatory Research Institute summarizes the justifications for multi-year rate plans from both the perspective of the utility, and from an interest in improving utility performance.[9] The six benefits identified from a utility perspective are:

1. More predictable revenues for utilities, bolstering their financial health;
2. Spreading of rate increases over a longer period;
3. More predictable rates for customers;
4. Stronger performance incentives;
5. Timely recovery of costs for new capital projects; and
6. Fewer general rate cases over time.[10]

This report also notes that supporters of MRPs argue that MRPs "avoid 'earnings' attrition by preventing the erosion of a utility's rate of return that could occur under an historical test year."[11] Furthermore, it states, "From a utility's perspective, the biggest benefit from MRPs probably comes from an improved opportunity to earn its authorized rate of return. That is, the mitigation of regulatory lag that can jeopardize a utility's financial health."[12]

[9] Ken Costello, National Regulatory Research Institute, *Multiyear Rate Plans and the Public Interest* (October 2016), http://nrri.org/download/nrri-16-08-multiyear-rate-plans/ ("NRRI report").
[10] NRRI report at 16.
[11] *Id.*
[12] *Id.*

Q. So is a multi-year rate plan a form of regulatory lag, or a solution for regulatory lag?

A. Both. A multi-year rate plan is a form of regulatory lag, in that the prices the utility charges in the near and medium term are fixed. However, it is also a solution to regulatory lag, in that the prices a utility charges its customers are updated in a manner consistent with the changes in prices that the utility itself faces.

Q. Why is a multi-year rate plan a good idea?

A. From the list above, Staff is interested in a multi-year rate plan for reasons 1, 3, 4, 5, and 6. Recent history, and Avista's stated plans for continued large capital additions in the coming years, all point toward the likelihood that absent a multi-year rate plan, Avista will continue to file back-to-back rate cases.

A multi-year rate plan will address the Commission's expressed concerns of breaking the pattern of annual rate filings. A properly designed rate plan would also share risks between customers and Avista, and incentivize the company to become more efficient in its operations, while providing for the opportunity to achieve the target rate of return.

Q. On page 49 of Exh. SLM-1T, Avista witness Scott Morris states that "the existing one-way earnings test" for Avista's Washington electric and natural gas operations acts as one of a few "checks and balances" to "ensure that retail rates for the duration of the multi-year rate plan are fair for customers." Do you agree?

A. Perhaps. Let us revisit what is meant by a “one-way” earnings test. The earnings test is “one-way” in the sense that it is only relevant when the Company over-earns, and is not relevant when the Company under-earns. This is how most earnings tests work. When the earnings test is activated, half of the “over-earned” revenues are returned to customers, and the company keeps the remaining half.

Some sharing of “over-earned” revenues may be appropriate, as an earnings-sharing mechanism ensures that existing customers will benefit from cost-cutting measures implemented by the company during the course of its rate plan. Such a mechanism acts as a hedge against the possibility that revenues were errantly over-estimated as well. An earnings sharing mechanism maintains an incentive for the Company to reduce costs and increase productivity.

That said, the Commission may want to consider eliminating earnings-sharing during the course of the rate plan. Staff does not endorse doing so, but wishes to raise the merits for the Commission’s consideration. The reason for doing so would be to maximize the incentive to cut costs during the course of the rate plan, under the expectation that lower operating costs would be captured in the test year of a future rate case. Alternatively, the Commission may wish to consider an earnings sharing band, wherein earnings sharing is only triggered at some level above the authorized rate of return.

Q. Can you summarize your policy recommendations regarding multi-year rate plans? Should the Commission approve a multi-year rate plan?

A. The Commission should approve a multi-year rate plan. In particular, it should approve a three-year rate plan with the electric and natural gas revenue increases for years two and three detailed in Exh. CSH-2 (electric) and Exh. CSH-3 (natural gas).

The Commission should maintain the existing earnings sharing program through the multi-year rate plan, regardless of the Commission's future decision on whether to continue or end decoupling. Staff believes that the existing program appropriately allocates risk between ratepayers and investors. Maintaining the current program will also allow customers to more immediately enjoy the benefits of any efficiency gains the company is able to achieve.

The Commission should also adopt Ms. Andrews's proposal for capital addition reporting, also known as "attestation."[13]

Staff witness Mr. Gomez recommends that the Commission maintain the current power cost baseline until a) Avista's next general rate case or b) the total credit balance owed to ratepayers of $21.3 million falls below $10 million, whichever occurs sooner.

Finally, the Commission should require the company to file a general rate case within twelve months of the conclusion of the multi-year rate plan. In that case, the Commission should require that the Company present testimony that describes the largest capital additions[14] made over the duration of the multi-year rate plan.

[13] Andrews, Exh. EMA-1T at 28:15-18.

[14] Here "largest capital additions" can be interpreted as any capital project placed in service in which the total expected (or, for complete projects, actual) cost is greater than or equal to 0.5% of the net plant in service in the preceding calendar year. The Commission can exercise its considerable judgment here on what is an appropriate threshold.

Q. On what grounds has the Commission previously established a multi-year rate plan for a regulated utility?

A. Most recently, the Commission adopted a multi-year rate plan for Puget Sound Energy.[15] One basis for the Commission's decision was that the rate plan provided rate predictability.[16] The Commission also noted that the plan was an "innovative approach" that provided PSE incentives to cut costs in order to earn its authorized rate of return.[17] Finally, the Commission supported its decision because the reduced number of rate filings would break the pattern of almost continuous rate case filings.[18] Since 2012, Avista has filed a general rate case in every year save for 2013. There was no general rate case in 2013 because the Commission approved a two-year rate plan in Avista's 2012 general rate case.[19]

C. The decoupling "soft-cap" and MRPs

Q. What is the decoupling "soft-cap?"

A. On decoupled schedules, companies maintain a deferral balance to account for under- or over-collection of revenues for the given schedule. Often, there are bounds placed on how much rates can change when "trueing up" the rates to account for the deferral balance. Avista operates under such a mechanism. In the case of an under-

---

[15] *Wash. Utils. & Transp. Comm'n v. Puget Sound Energy*, Dockets UE-130137 and UG-130138, Order 07, Final Order Authorizing Rates (June 25, 2013).
[16] *Id.* at 66, ¶ 150.
[17] *Id.*
[18] *Id.*
[19] *Wash. Utils. & Transp. Comm'n v. Avista Corp. d/b/a Avista Utils.*, Dockets UE-120436 and UG-120437, Order 09, Final Order Rejecting Tariff Filing, Accepting with Conditions Multi-Party Settlement Agreement, Authorizing Tariff Filing, and Requiring Compliance Filing (Dec. 26, 2012).

collection, Avista can increase rates by no more than 3% in order to collect those deferred revenues. If a 3% rate increase is insufficient to clear the deferral balance, those funds are rolled forward.

Q. What is the relevance of the decoupling soft-cap with a multi-year rate plan?

A. A multi-year rate plan will often require an increase in rates in the second and third years of the rate plan. Suppose, for the sake of discussion, that a hypothetical rate plan calls for an increase of 2%, and that the utility in question operates under a decoupling soft-cap of 3%. If improperly structured, the rate increase from the multi-year rate plan can complicate the decoupling soft-cap. In this instance, a 2% increase from the MRP could leave only 1% of room left for a rate increase to correct prior under-collection of decoupled revenues. This was a matter relevant in the recent Puget Sound Energy general rate case.

Q. What recommendation would you make?

A. The decoupling soft-cap should use a 3% threshold that is independent of any rate increases from the multi-year rate plan. The revenue increase authorized by the decoupling mechanism should first be determined. Then, the revenue increase called for by the rate plan should be applied, followed by the application of the increase in revenues called for by the decoupling mechanism.

D. Other policy matters

Q. Are there any other matters that you would like to bring to the Commission's attention?

A. Staff would like to remind the Commission that Avista's decoupling mechanism, as agreed in settlement and approved by the Commission, is effective for five years, ending December 31, 2019,[20] approximately one and a half years prior to the end of Staff's proposed rate plan. An evaluation of the decoupling mechanism's first three years, from 2015 through 2017, is expected in 2018. Staff understands the settlement, and the Commission's order approving it, to have contemplated the continuation of the Company's decoupling mechanism through the end of 2019, without requiring reapproval in any intervening rate case, so that the mechanism can be properly evaluated.

Q. Are there any other requirements the Commission should consider in establishing the Company's rates?

A. Yes. Staff draws the Commission's attention to two ongoing programmatic requirements it may wish to adjust in this rate case. First, Avista's third-party evaluation of its existing decoupling mechanisms is expected in 2018.[21] This evaluation should explicitly include a comparison of low-income conservation program participation with general conservation program participation to inform the

[20] *See Wash. Utils. & Transp. Comm'n v. Avista Corp. d/b/a Avista Utils.*, Dockets UE-140188 and UG-140189, Order 05, 11-14, ¶¶ 22-28 (Nov. 25, 2014); *Wash. Utils. & Transp. Comm'n v. Avista Corp.*, Dockets UE-140188 and UG-140189, Settlement Stipulation, 6-7, ¶ 13 (Nov. 25, 2014).
[21] *Id.*

level of spending on low-income conservation programs. Staff also urges the Commission to require the company to include a natural gas conservation target, complete with penalties for failure and incentives for achievement in any future decoupling proposals.

Second, Staff has continued to monitor Avista's implementation of its Low-Income Rate Assistance Program.[22] Staff believes the company is in compliance with the requirements of the Commission's order. However, Staff is disappointed that the Company's testimony makes no mention of the goals adopted by the Commission and fails to connect the programs delivered by the Company with the goals approved by the Commission. Staff urges the Commission to direct the Company to address how it plans to implement these goals in its compliance filing in this rate case. Staff also recommends that the Commission extend the LIRAP plan one additional year, through 2020, with the same percentage increases established in 2014.[23]

V. END OF PERIOD RATE BASE

Q. What is the purpose of electric adjustment 3.15 in Exh. EMA-3 and natural gas adjustment 3.14 in Exh. EMA-7 in the Company's "EOP Rate Base Study" presentation?

---

[22] *See Wash. Utils. & Transp. Comm'n v. Avista Corp. d/b/a Avista Utils.*, Dockets UE-150204 and UG-150205, Final Order Rejecting Tariff Filing , Accepting Partial Settlement Stipulation, Authorizing Tariff Filings, Order 05, 77-80, ¶¶ 223-34 (Jan. 6, 2016).

[23] *Id.* at 80, ¶ 234. The extension would mean that by Aug. 15, 2020, Avista should file revisions to Schedules 92 and 192 to increase LIRAP funding by 7% for the program year beginning Oct. 1, 2020.

A. The purpose of these two adjustments is to advance the effective rate base figures from the restated test year all the way up to Avista's expectations of rate base balances as of December 31, 2017. These two adjustments are given the flawed title "EOP 2017 Capital Net Rate Base." They are conceptually identical to Adjustment 18.01 in Exh. EMA-5, and Adjustment 18.01 in Exh. EMA-9.

Avista witness Ms. Andrews justifies these adjustments on the grounds that they "best reflect a recognition of plant that will be actually in-service during the period the new rates are in effect."[24] There is, however, no similar adjustment for rate base additions between December 31, 2017, and the expected rate-effective date of May 1, 2018.

Q. Do you object to the characterization of these adjustments as "EOP rate base?"[25]

A. Yes. While the company may defend this presentation on the grounds that this adjustment aims to arrive at a rate base figure expected at the end of *a* period, this is a distortion of the concept of end-of-period ("EOP") rate base.[26]

The phrase "EOP rate base" and its variants are generally reserved for reference to <u>test year</u> balances. Avista's adjustments include adjustments well beyond the test year.

These adjustments are more accurately described as indiscriminate pro forma rate base additions, regardless of the size of the individual capital additions contained

[24] Andrews, Exh. EMA-1T at 12:14-15.
[25] *Id.* at 12:9.
[26] *Id.* at 11:8-32 (particularly line 29).

in the adjustment. This latter characteristic becomes clear when comparing the adjustments to Adjustment 3.10 in Exh. EMA-3 and Adjustment 3.10 in Exh. EMA-7, which do consider the magnitude of the capital additions contained in the adjustments. Put more simply, Adjustment 3.15 in Exh. EMA-3 and Adjustment 3.14 in Exh. EMA-7 contain rate base additions expected to occur by December 31, 2017, that the company does not believe fit the threshold that Staff has used for consideration of pro forma adjustments involving capital additions. These adjustments represent very aggressive pro forma capital addition adjustments—far beyond an adjustment to the method of calculating test year rate base figures.

Q. Why are these capital additions typically not accounted for?

A. The primary reason is that these capital additions are not "major," in Staff's analytical framework.[27] Other intervening parties typically have their own ways of determining which capital additions are "major," but the nature of the effect is the same—some capital additions after the test year go unconsidered for rate-making purposes, due to their relatively small magnitude.

Q. Why has Staff typically distinguished between major and "non-major" capital projects?

A. Staff makes this distinction to focus its limited resources on the most significant capital additions made after the conclusion of the test year. Companies can and often

[27] See the testimony of Staff witness Ms. Scanlan for further discussion on major pro forma plant additions.

do produce hundreds of potential capital additions that are not captured in the test year, that they expect to be in service during the rate-effective period. However, Staff, intervening parties, and the Commission prefer not to rely on expectations alone. The scope of projects considered for pro forma treatment must be narrowed in order to dedicate a sufficient amount of scrutiny and attention to the merits of individual projects.

Additionally, Staff can only testify to those capital additions it has found appropriate for ratemaking consideration, and can only testify to the amounts demonstrated to be in-service prior to the date in which testimony is made.

Finally, pro forma plant adjustments should be limited in number and scale because it is simply not feasible for a company to demonstrate, or for intervening parties to verify, with certainty and specificity, every single capital transfer to plant, and then to demonstrate, capture, and verify offsetting benefits for every single capital transfer to plant in separate pro forma adjustments.

The side-effect is that rate base figures run the risk of being under-stated relative to what is in service during the rate-effective period. This is a classic example of regulatory lag.

Q. What is one measure that the Commission often exercises in order to counter this known cause of regulatory lag?

A. One measure that the Commission exercises is the use of end-of-period rate base accounting *for the test year*.[28] This adjustment transforms test year rate base balances

[28] This is what is referred to in bullet point 5 in paragraph 82 of Order 06, in *Wash. Utils. & Transp. Comm'n v. Avista Corp. d/b/a Avista Utils*., Dockets UE-160228 and UG-160229 (Dec. 15, 2016).

from average-of-monthly-average accounting, which best matches the effective rate base balances throughout a year, to end-of-period accounting, which reflects rate base balances at the end of a test year, when those balances are almost always their largest. This transformation in accounting goes some way towards compensating for the unrecognized rate base additions that were too small, too numerous, or too late in the rate case schedule to account for during a rate proceeding.

Note that this is distinct from what is proposed in Adjustment 3.15 in Exh. EMA-3, and Adjustment 3.14 in Exh. EMA-7, which are much further conceptual leaps.

Q. Why is end-of-period accounting not the standard method of calculating test year levels of rate base?

A. The primary reason that average-of-monthly-averages (AMA) accounting is favored over end-of-period accounting is that AMA more closely follows the matching principle.

Q. Is Staff supporting end-of-period rate base accounting <u>for the test year</u>?

A. Yes. The transformation of test year rate base balances from AMA to EOP is captured in Staff's electric adjustment 2.19 and natural gas adjustment 2.16.

For electric service, converting from AMA to EOP accounting inflates rate base by $69.7 million, yielding a $7.00 million increase in revenue requirement. For natural gas service, this treatment increases rate base by $14.2 million, yielding a $1.42 million increase in revenue requirement.

Q. Why is Staff supporting this adjustment?

A. As stated previously, EOP has been found to be appropriate to counter the effects of regulatory lag. Staff recognizes that an AMA accounting, with limited pro forma adjustments, will likely understate the level of rate base in service during the first year of the rate plan. This understatement is an example of regulatory lag.

An EOP adjustment is also justified for Avista given the low load growth expectations Staff has for Avista. In times of more accelerated load growth, such load growth was more forgiving of the understatement of rate base that typically occurs when using AMA accounting.

In the context of a multi-year rate plan, this adjustment is of particular importance. Revenue requirements for Year One are developed from an estimate of rate base in the modified historical test year. In the second and third year of Staff's multi-year rate plan, those revenues are escalated forward. Or, in other words, Year 2 and Year 3 revenues are a function of Year 1 revenues, and Year 1 revenues are a function of the rate base levels established in the modified historical test year. Thus, the effects of the choice between AMA and EOP for the test year carry forward throughout the entire rate plan.

Q. What is the effect of Staff's electric adjustment 3.15, and natural gas adjustment 3.14?

A. For the reasons described above, these adjustments add zero dollars to rate base and expenses.

VI. COMMENTARY ON AVISTA'S RATE PLAN

Q. How is Avista's rate plan structured?

A. Avista's rate plan contains two components. The first component is a purported modified historical test year with limited pro forma adjustments, which corresponds to year one of the rate plan. Staff witness Kathi Scanlan provides Staff's commentary on Avista's modified historical test year.

The second component is a so-called "K-factor" model that is used to develop revenue requirements for years two and three of the rate plan. This model creates escalation rates that are applied to the escalation base in Year One in order to develop revenue requirements for Year Two. Similarly, the Year Two escalation base is escalated to develop Year Three revenue requirements.

Q. Please discuss Avista's "K-Factor" model.

A. Avista develops a rate plan structure in which revenues are escalated by a factor that it terms "the K-Factor." I wish to steer the Commission and the record away from this terminology, as it violates how that term is traditionally used in multi-year rate plans and conflates several rate plan concepts into one term.

Q. Please elaborate on the "K-factor" terminology.

A. A "K-factor" is typically meant to refer to a growth factor for capital, hence the use of "K", the common economic abbreviation for "capital." Other factors are also often discussed in rate plan literature: X-factor (for productivity growth; also known as a "productivity offset") and Q-factor (service quality) also see use.[29]

Avista's use of the term "K-factor" refers to a composite revenue growth factor, rather than specifically to the growth in capital. As a result, Staff will not refer to Avista's model as a "K-factor" model, and discourages other parties and the Commission from doing so.

Q. Jargon aside, how is Avista's revenue growth factor constructed?

A. Avista's revenue growth factor is developed from four individual growth factors. Those factors are: (1) the depreciation growth factor; (2) the O&M expense growth factor; (3) the Taxes Other Than Income growth factor; and (4) the Net Plant After Accumulated Depreciation and Federal Income Tax (Net Plant ADFIT) growth factor.

The O&M expense growth factor in Avista's model is in actuality only 90% of the historical growth rate, an adjustment made by Avista in order to reflect a 10% efficiency adjustment.[30] This efficiency adjustment is often also referred to as a "productivity offset." Finally, the Net Plant ADFIT growth factor reflects Avista's expected reduction in growth in net plant in 2019 and 2020.[31]

[29] *See* Lesser and Giacchino, *Fundamentals of Energy Regulation*, Chapter 8, Section 4 (2007).
[30] Andrews, Exh. EMA-1T at 31:8-11.
[31] *Id*.

Q. What percentages of revenues do these cost-drivers represent?

A. After removing power supply revenues, these four types of costs subject to escalation represent the following shares of electric revenues: O&M expense (~ 35%); depreciation expense (~ 20%); taxes other than income (9.8%); and Net Plant ADFIT (34.4%).

Similarly for natural gas, the four types of costs subject to escalation represent the following shares of natural gas revenues: O&M expense (41.4%); depreciation expense (20.13%); taxes other than income (7.33%); and Net Plant ADFIT (31.15%). These shares are with natural gas commodity revenues removed.

Each of these cost-causers is given a growth factor. The growth factor is multiplied by the share of revenues found above, and four figures are produced. The sum of these four figures—a weighted average of the component escalation rates—represents what Avista calls a "K-factor," and what Staff calls a composite escalator.

Q. Please discuss Avista's depreciation growth factor.

A. Avista calculates its depreciation growth factor as the compound growth rate of the total depreciation and amortization expense from 2013 to 2016, according to Avista's respective Commission Basis Reports.

Q. Please discuss Avista's O&M expense growth factor.

A. Avista calculates its O&M expense growth factor by first finding the compound growth rate of Adjusted Operating Expenses from its 2013 to 2016 Commission Basis Reports. Then, Avista applies a 10% "efficiency adjustment," which produces a value that is 90% of the above historical compound growth rate. This is not an unusual step to take in the development of a multi-year rate plan.[32]

Q. Please discuss Avista's Taxes Other Than Income growth factor.

A. Avista calculates its Taxes OTI growth factor by finding the compound growth rate of Adjusted Taxes OTI from its 2013 to 2016 Commission Basis Reports.

Q. Please discuss Avista's Net Plant ADFIT growth factor.

A. Unlike the other growth factors, this component factor is *not* developed from historical data. Instead, it is developed from prospective data. Avista finds the compound growth rate of the 2018 through 2020 expected Net Plant ADFIT figures from Avista's "Rate Year Study."

Q. Is it unusual for a multi-year rate plan to be based on planned investment?

A. No. In fact, under PSE's recently concluded multi-year rate plan, plant growth was found by evaluating a one-page schedule of projected growth in Net Plant in Service.[33]

Q. Three of Avista's four growth factors use the period 2013-2016. How does Avista justify the use of this period?

---

[32] NRRI report at 31; *see also* U.S. Department of Energy, GRID Modernization Laboratory Consortium, *State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities*, p. 4.3 (July 2017).

[33] *Wash. Utils. & Transp. Comm'n v. Puget Sound Energy*, Dockets UE-121697 and UG-121705, Brief of Public Counsel, 15, ¶ 32 (May 30, 2013).

A. Ms. Andrews states that this period is chosen because this period is "more current" and that these years "already included the effects of reductions in O&M after 2012."[34]

Q. Do you have any concerns using this particular period of time for three of the four component factors?

A. Yes. The reductions in O&M after 2012 are relevant to the escalation of O&M expense. It is much less obvious why reduced O&M expenses after 2012 should result in using the 2013-16 period to find historical growth in Taxes OTI and Depreciation expenses. Staff, as we will explore later, finds it more appropriate to use a longer period of time to evaluate the historical growth in these particular expenses.

Q. What observations do you have about how Avista models productivity growth/growth in operating expenses?

A. Productivity growth factors usually adopt one of two approaches: an approach based on the company's past performance or expected future performance, or, a broader price index. Avista argues against the use of indices (specifically the Consumer Price Index, or "CPI"), and argues for a method that reflects the company's historical performance.

I have a few concerns with Avista's preferred approach. First, this approach can penalize a company for its past high efficiency, or reward it for poor productivity

[34] Andrews, Exh. EMA-1T at 33:6-12.

in the past. This is, admittedly, somewhat mitigated by Avista's voluntary use of a stretch factor or efficiency adjustment.

Secondly, and perhaps more importantly, the use of company-specific data over measures of productivity from the utility industry is counter to the goal of providing a proxy for market competition that lies at the heart of the use of a multi-year rate plan. A key desire of regulators adopting a multi-year rate plan is to encourage utilities to operate more efficiently. Providing for rates that reflect the underlying productivity growth in the utility industry best meets that goal. An index-based approach better reflects external cost drivers to the company and encourages a utility to match (or with a stretch factor, exceed) industry norms.

Finally, because a multi-year rate plan is a prospective exercise (especially in comparison with traditional rate-making), as well as an extraordinary method of rate-making, a conservative approach is wise. An index-based approach is best on this criterion.

VII. STAFF'S RATE PLAN MODELS

Q. How is Staff's rate plan structured?

A. Staff's rate plan structure is similar to that of the company, although with meaningful distinctions. Year One revenues are developed through the principled use of a modified historical test year, with limited pro forma adjustments. From this base, escalators are applied to develop revenues for Years Two and Three. Those escalation rates are developed in Staff's composite escalation factor model.

As with Avista's proposal, the revenue requirements formulated in Staff's modified historical test year form the base from which subsequent years' revenues are developed. As a result, the practices used in the development of Year One revenue requirements will echo into the Year Two and Year Three revenue requirement figures.

A. Escalating O&M Expenses

Q. What methods did Staff consider for escalating O&M expenses?

A. Staff considered both the Company's proposal, as well as an index-based approach. Staff chose the latter option.

Q. Please describe Staff's perspective on appropriate indices.

A. The merits of an index-based approach depends in large part on the index or indices chosen. Care must be taken to ensure that the chosen indices are relevant to the industry in question. Ms. Andrews does a fine job explaining why a Consumer Price Index is an inappropriate index for our purposes here.

Q. What indices does Staff use?

A. Staff uses two indices: the Employment Cost Index for Utilities[35], or ECI-U, and the Producer's Price Index for Utilities[36], or PPI-U. The Producer's Price Index for Utilities has several "sub-indices" that Staff makes use of as well.

Q. Please describe the Employment Cost Index.

A. The Employment Cost Index measures costs of employees to employers. It is designated a Principal Federal Economic Indicator by the Bureau of Labor Statistics. It measures not only wages, but benefits the company provides to employees, such as health insurance, retirement plans, and paid time off. Staff uses a form of the Employment Cost Index that is specific to utilities.

Q. Please describe the Producer Price Index.

A. The Producer Price Index measures costs to producers. As with the Employer Cost Index, Staff used the utility-specific subset of the Producer Price Index.

Q. How does Staff develop its escalation factor for electric O&M expenses?

A. For electric operations, Staff develops an escalator that gives one-half weight to the Employment Cost Index for utilities, and one-half weight to a composite of the transmission, distribution, and generation indices; Staff calls this composite "PPI-

[35] U.S. Bureau of Labor Statistics, Employment Cost Index: Total compensation for Private industry workers in Utilities [CIS2014400000000I] (September 22, 2017), retrieved from FRED, Federal Reserve Bank of St. Louis, https://fred.stlouisfed.org/series/CIS2014400000000I.

[36] U.S. Bureau of Labor Statistics, Producer Price Index by Industry: Utilities [PCU221221] (September 22, 2017), retrieved from FRED, Federal Reserve Bank of St. Louis; https://fred.stlouisfed.org/series/PCU221221.

Custom." Linear regression is used to find the linear growth rate of costs in all of these indices over the period 2007 to 2016. The Employment Cost Index for utilities suggests a growth rate of 2.48%.

PPI-Custom is formed from using the following indices: the index for Electric Power Generation[37]; the index for Electric Bulk Power Transmission[38] and Control; and, the industry index for Electric Power Distribution.[39] These indices are given weight in PPI-Custom based on the Avista's 2016 proportion of generation, transmission, and distribution plant. PPI-Custom suggests a growth rate of 2.24%.

Giving the Employment Cost Index for utilities one-half weight, and PPI-Custom one-half weight, produces an electric O&M escalator of 2.36%.

Q. Can you provide tables that illustrate what is described above?

A. The table below illustrates the composition of the PPI-Custom measure, which is used only for electric service:

---

[37] U.S. Bureau of Labor Statistics, Producer Price Index by Industry: Electric Power Generation [PCU221110221110] (September 22, 2017), retrieved from FRED, Federal Reserve Bank of St. Louis, https://fred.stlouisfed.org/series/PCU221110221110.

[38] U.S. Bureau of Labor Statistics, Producer Price Index by Industry: Electric Bulk Power Transmission and Control [PCU221121221121] (September 22, 2017), retrieved from FRED, Federal Reserve Bank of St. Louis, https://fred.stlouisfed.org/series/PCU221121221121.

[39] U.S. Bureau of Labor Statistics, Producer Price Index by Industry: Electric Power Distribution [PCU221122221122] (September 22, 2017), retrieved from FRED, Federal Reserve Bank of St. Louis, https://fred.stlouisfed.org/series/PCU221122221122.

	Relative Share of Net Plant, 2016 CBR	2004-16 PPI Rate of Growth	Contribution to PPI-Custom
	[A]	[B]	[C] = [A]*[B]
Production	40.98%	1.70%	0.70%
Transmission	18.15%	3.15%	0.57%
Distribution	40.86%	2.38%	0.97%
TOTAL	100%		2.24%

The table below illustrates the composition of the O&M escalator for electric service:

ECI	PPI-Custom	Electric O&M Escalator
[A]	[B]	[C] = ([A] + [B]) ÷ 2
2.48%	2.24%	2.36%

Q. How does Staff develop its escalation factor for <u>natural gas</u> O&M expenses?

A. For natural gas operations, Staff's escalator is the average of the Producer Price Index for Utilities and the Employment Cost Index for Utilities. This produces a natural gas O&M escalator of 2.03%. This is illustrated in the table below:

ECI	PPI-Util	Natural Gas O&M Escalator
[A]	[B]	[C] = ([A] + [B]) ÷ 2
2.48%	1.58%	2.03%

Q. Why doesn't Staff use the Producer Price Index by Industry: Natural Gas Distribution?[40]

A. Staff did not use this index because it appears to give excessive weight to natural gas commodity costs, biasing the index downwards.

Q. How do you address Ms. Andrews's critiques of the use of cost indices?

A. Ms. Andrews presents two critiques of the use of cost indices in a multi-year rate plan: a thorough critique of the use of CPI, and a critique of cost indices generally.

I strongly agree with Ms. Andrews's critique of the Consumer Price Index, or CPI, in that the CPI does not accurately capture costs facing the utility industry.[41]

However, the use of utility industry indices addresses Ms. Andrews's best critique of CPI: "…CPI does not track costs typically implicit in the operations of a utility."[42] Utility-specific indices have this exact feature, and are therefore appropriate for consideration. The use of an index accomplishes another important goal as well. Because Avista can profit by keeping changes in its costs below the industry average, reliance on the index encourages efficiency.

---

[40] U.S. Bureau of Labor Statistics, Producer Price Index by Industry: Natural Gas Distribution [PCU221210221210] (September 22, 2017), retrieved from FRED, Federal Reserve Bank of St. Louis, https://fred.stlouisfed.org/series/PCU221210221210.
[41] Andrews, EMA-1T at 35:1-36:28.
[42] *Id.* at 33:1-2.

B. Escalating Net Plant

Q. What methods did Staff consider for escalating plant?

A. Staff considered the use of escalators based on the following methods:

1. A historical trend in net plant growth;
2. Avista's projected net plant additions through the course of the rate plan ("the Avista approach");
3. Plant additions deemed outside of the company's control;
4. An escalator adjusted by a "stretch factor";
5. No escalation of plant at all.

Q. Please describe each of these methods.

A. Under the first method, the analyst must determine the historical rate of plant growth using either a compound growth rate (see Avista's method for Taxes OTI and Depreciation expense) or a linear growth rate. The analyst must also determine the most appropriate period of time over which to assess an historical rate of growth.

The second method uses Avista's projected net plant additions over the course of the rate plan. This is in fact the approach that Avista uses, forgoing any consideration of historical rates of plant addition. Notably, Avista's approach in this case produces a smaller escalator for electric plant additions than using a historical compound growth rate, or a historical linear growth rate.

The third method has an analyst review all three years' worth of Avista's planned plant additions, and then requires the analyst to make an assessment of how much discretion Avista has for each planned plant addition.

The fourth method is similar to the logic used in Avista's escalation of O&M expenses. A rate of growth is developed and then adjusted downwards by a "stretch factor." In the case of Avista's O&M escalator, this stretch factor is known as an "efficiency adjustment."

Finally, the fifth method simply does not escalate plant over the course of the rate plan.

Q. What approach does Staff adopt in this case?

A. Staff adopts a form of the second approach identified above, otherwise known as "the Avista approach."

Q. Before explaining why Staff adopted Avista's approach, please explain why Staff declined to use the other five options it considered?

A. The first option—escalating plant based on historical levels of plant additions—was rejected because the *rate* of plant additions throughout the multi-year rate plan is better represented by the second option. An escalation rate based on historical levels of plant additions would also produce a higher escalation rate than the second option.

The third option—identifying plant additions that are caused by matters outside of the control of the company—was rejected because it skirts too close to weighing in on the prudency of plant additions that have yet occurred. Sorting through even a subset of each and every plant addition scheduled to occur through the period of the rate year, and determining the degree to which each project is outside of the control of the company, would also be a troublesome task.

The fourth option—developing an escalator adjusted by a "stretch factor—was rejected because the regulatory lag inherent in escalating from Staff's modified historical test year accomplishes the same ends.

Finally, Staff rejected the fifth method—not escalating plant at all—because it is counter to the rationale for a multi-year rate plan. Based on Avista's representations about its capital spending program, Staff anticipates that the rate of plant growth over the next few years will exceed the expected growth in revenues. If there is no escalation in plant, the company's rate base will likely be undervalued during the rate plan to a degree that will not provide the company with a reasonable opportunity to achieve its authorized rate of return.

Q. Having rejected these four approaches, Staff adopts an approach similar to Avista's. Why?

A. Adoption of this method is done keeping in mind that the escalation rate proposed by Avista is lower than what would be suggested by looking at historical rates of plant growth. Adoption of this method is tantamount to authorizing interim recovery of capital costs, while deferring a permanent decision on the prudency of specific capital additions until a later rate case. This approach provides for recognition of continuing growth in rate base, while preserving the known benefits of regulatory lag.

Q. What distinguishes Staff's method from Avista's?

A. Staff applies its plant escalator to a principled modified historical test year, with limited pro forma adjustments, whereas Avista applies its plant escalator to a Year One base that, in Staff's view, is inflated due to Avista's unprincipled use of "EOP" accounting. Functionally, Staff's lower base preserves regulatory lag that benefits customers, acts as a disincentive towards over-capitalization, and provides only for interim relief. It does this while recognizing that the company will almost certainly continue to make rate base additions during the course of the rate plan.

Staff is not setting revenue requirements based on the projected *level* of rate base and net plant in future years, as is effectively the case with Avista's proposal. Staff is merely developing an escalation *rate*¸ which is applied to a base established in Staff's modified historical test year. That rate is developed by finding the percent growth in rate base that Avista expects over the course of the rate plan, and it is applied to a rate base figure that Staff's witness for year one can attest to.

The only way that Staff's approach would provide for Avista's projected plant balances is if Staff used the same base to escalate from that Avista used. That is simply not the case here.

Q. Are there any other options the Commission could consider?

A. The Commission could entertain the idea of allowing Avista to recover Construction Work in Progress (CWIP) in rate base during the rate plan, rather than escalating net plant. The Commission alluded to this possibility in its most recent Avista GRC order.[43] If the Commission were to adopt this approach for net plant, adopting an escalator that does not consider plant growth would be appropriate.

Q. If the Commission were to allow CWIP in rate base during the rate plan, what composite revenue escalators would Staff recommend?

A. Using Staff's approach, an escalation rate of 1.27% for electric service, and 1.63% for natural gas service would be appropriate in these circumstances.

Q. Please summarize the composite revenue escalators used by Staff and Avista.

A. A summary of these escalation rates can be found in the table below.

<u>Year 2 and Year 3 Escalators</u>

	Staff	Avista
Electric	2.32%	3.21%
Natural Gas	3.20%	4.65%

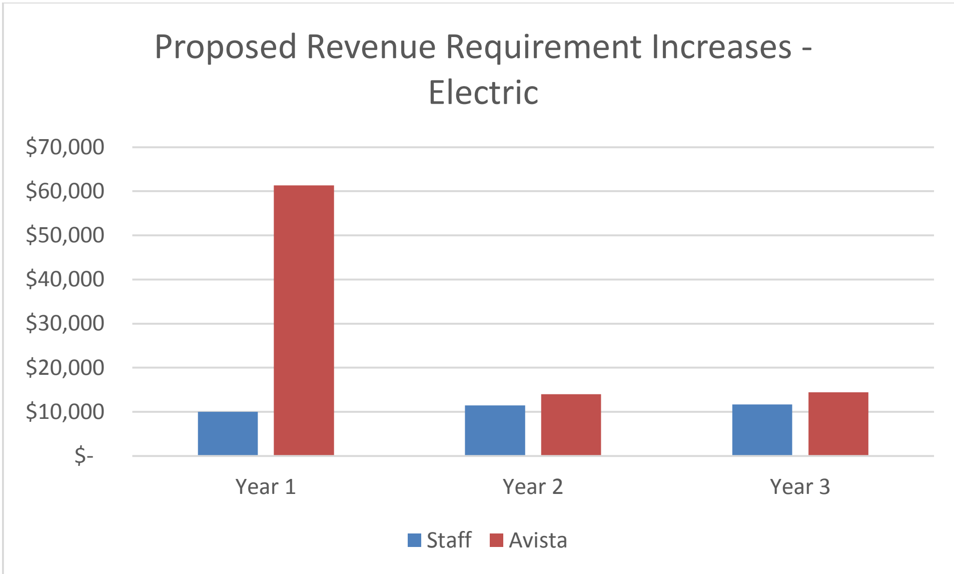
Q. Please summarize the revenue increases called for by Avista and Staff for electric service.

A. The proposed revenue increases in each year of the rate plan are presented in the charts and tables below:

<u>Proposed Rev. Reqmt. Increases - Electric</u>

	Year 1	Year 2	Year 3
Staff	$ 10,034	$ 11,450	$ 11,716
Avista	$ 61,356	$ 13,983	$ 14,432

[43] *See Wash. Utils. & Transp. Comm'n v. Avista Corp. d/b/a Avista Utils.*, Dockets UE-160228 and UG-160229, Order 06, Final Order Rejecting Tariff Filing, 49, ¶ 82 (Dec. 15, 2016).

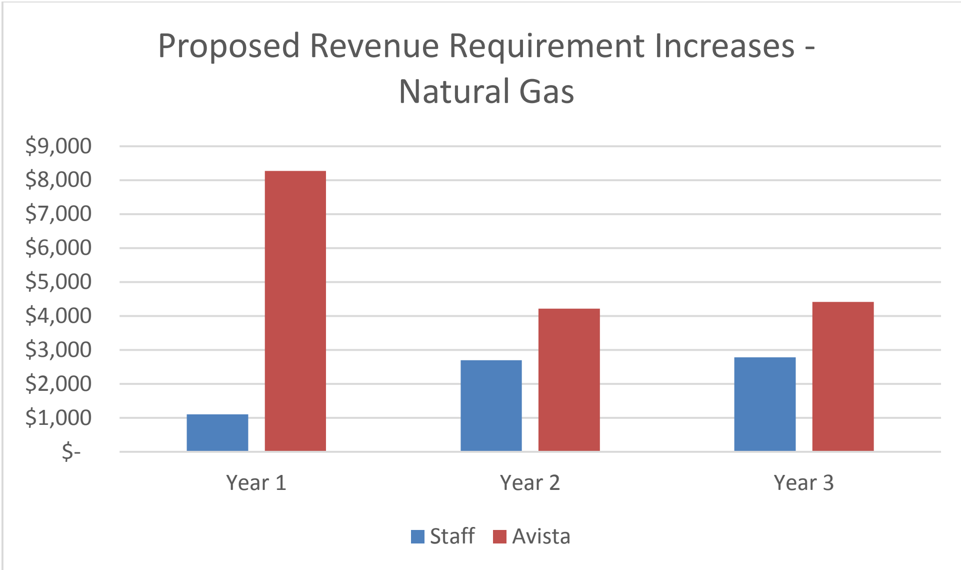


Q. Please summarize the revenue increases called for by Avista and Staff in natural gas service.

A. The recommended revenue increases for natural gas service can be seen in table and chart format below.

Proposed Rev. Reqmt. Increase - Natural Gas

	Year 1	Year 2	Year 3
Staff	$ 1,215	$ 2,701	$ 2,788
Avista	$ 8,269	$ 4,220	$ 4,417

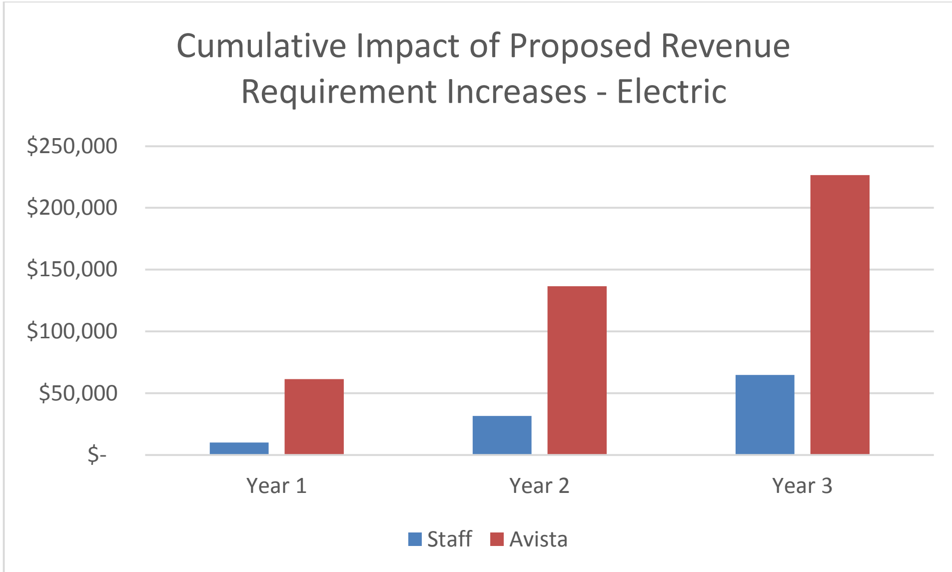


Q. Please summarize the <u>cumulative</u> effective of the <u>electric</u> revenue increases proposed by Avista and Staff in this case.

A. The cumulative effect of the proposed electric revenue increases are displayed below, in table and graph format. A useful way to interpret these figures is that these are the total additional revenues customers would pay above existing rates, due to the proposed rate plans.

<u>Cumulative Electric Revenue Increases</u>

	Year 1	Year 2	Year 3
Staff	$ 10,034	$ 31,519	$ 64,718
Avista	$ 61,356	$ 136,695	$ 226,466

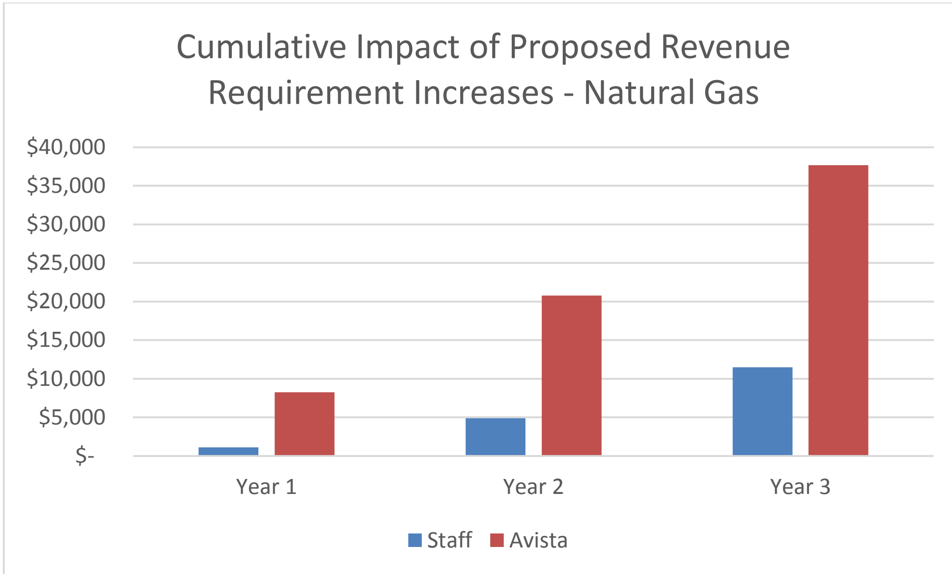


Q. Please summarize the <u>cumulative</u> effective of the <u>natural gas</u> revenue increases proposed by Avista and Staff in this case.

A. The cumulative effect of the proposed natural gas revenue increases are displayed below, in table and graph format.

<u>Cumulative Natural Gas Revenue Increases</u>

	Year 1	**Year 2**	**Year 3**
Staff	$ 1,107	$ 4,911	$ 11,500
Avista	$ 8,269	$ 20,758	$ 37,664



VIII. REVIEW OF PARTIES' ESTIMATES IN DOCKETS UE-150204/UG-150205

Q. Has Staff reviewed rate base and expense estimates from Avista's 2015 general rate case?

A. Yes. I gathered estimates of rate base and expenses from the direct testimonies of Avista, Staff, and Public Counsel witnesses that produced revenue requirement figures. Review of these estimates may provide useful context when evaluating the issues in the present case.

Q. In percentage terms, how did the various estimates of <u>rate base</u> perform relative to what the 2016 Commission Basis Report stated?

A. Avista's electric attrition ("AVA Attr RB") study most closely estimated the rate base figures reported in the 2016 Commission Basis Report, as shown in the table below:

Estimates of Elec Rate Base, as % of CBR Actuals (2015 GRC/2016 Rate Yr)					
AVA Attr RB	AVA MHTY RB	Staff Attr RB	Staff MHTY RB	PC MHTY RB	CBR RB
101.50%	101.88%	95.66%	91.60%	90.20%	100.00%

Avista's natural gas attrition study also most closely estimated the rate base figures reported in the 2016 Commission Basis Report:

Estimates of Nat Gas Rate Base, as % of CBR Actuals (2015 GRC/2016 Rate Yr)					
AVA Attr RB	AVA MHTY RB	Staff Attr RB	Staff MHTY RB	PC MHTY RB	CBR RB
99.82%	97.06%	104.33%	90.81%	88.06%	100.00%

Q. In percentage terms, how did the various estimates of <u>expenses</u> perform relative to what the 2016 Commission Basis Report stated?

A. Staff's electric attrition study most closely estimated the total expense figures reported in the 2016 Commission Basis Report, and Staff's modified historical test year came in a close second. Public Counsel did not produce an explicit estimate of expenses:

Estimates of Elec Expenses, as % of CBR Actuals (2015 GRC/2016 Rate Yr)					
AVA Attr Exp	AVA MHTY Exp	Staff Attr Exp	Staff MHTY Exp	PC MHTY Exp	CBR Exp
105.34%	104.57%	100.81%	98.52%	0.00%	100.00%

No party produced reasonably accurate estimates of natural gas expenses when compared to the results reported in the 2016 Commission Basis Report:

Estimates of Nat Gas Expenses, as % of CBR Actuals (2015 GRC/2016 Rate Yr)					
AVA Attr Exp	AVA MHTY Exp	Staff Attr Exp	Staff MHTY Exp	PC MHTY Exp	CBR Exp
120.85%	121.27%	120.05%	118.06%	0.00%	100.00%

Q. What may explain the inaccurate estimates for natural gas expenses in the 2015 GRC?

A. For the attrition-study related estimates, the inaccuracy could be the result of using a quadratic formula to estimate expenses, rather than a linear formula. However, that does not explain the similarly inaccurate results produced by the parties' modified historical test year estimates. Another plausible answer may be that a shift in the P/T ratio (a ratio used to allocate costs between natural gas and electric service) may have shifted some costs away from natural gas service and towards electric service. If this occurred, it would have resulted in lower-than-expected costs allocated towards natural gas service, thus making it more likely that estimates would end up on the high end.

Q. Does this conclude your testimony?

A. Yes.