**BEFORE THE WASHINGTON UTILITIES
AND TRANSPORTATION COMMISSION**

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION,

Complainant,

v.

AVISTA CORPORATION, d/b/a AVISTA UTILITIES,

Respondent.

DOCKETS UE-240006 and UE-240007 (*Consolidated*)

POST-HEARING BRIEF OF AVISTA CORPORATION

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1 COMES NOW, Avista Corporation (hereinafter “Avista” or the “Company”), by and through its undersigned attorney, and respectfully submits this Post-Hearing Brief in the above-captioned matter.

2 This filing presents important issues that go well beyond the customary review of results of operations, cost of capital determinations, and rate spread and rate design. To be sure, those are important and are fully discussed below. But what sets this case apart are the dramatic changes in the landscape against which Avista operates: the tumult in the regional power supply market (unmet demand, fewer counterparties and hedging opportunities, and inability to fully monetize any surplus energy for the benefit of customers); the inability to set an appropriate “baseline” for the ERM to function as intended, yielding results that become unintentionally punitive given fewer tools available to the utility to manage the expense; and proposals that would undermine the multi-year rate plan (MYRP) legislation, striking at its very core, i.e., rejection of more than a one year plan (Staff) or disruption of the “portfolio” approach to subsequent “provisional” capital review (AWEC). These issues deserve to be highlighted early on, before being more fully addressed later in this Brief. To be sure, the resolution of these issues will weigh heavily on the financial well-being of Avista, as it provides the service its customers deserve.

- **Changing Power Market Conditions (Section III.A, below)**

3 "Market fundamentals" have changed. This includes the reduction in longer-term bilateral trading opportunities; greater use of organized markets such as the Energy Imbalance Market (EIM); changed State emission policies; inclusion of more variable resources in the mix; and lower resource adequacy in Region. For Avista, the implied market heat rate is overstated in Avista's traditional power supply modeling. The value of Avista's thermal fleet in reducing net power supply expense (NPE) in such modeling increased ten-fold up to $300M (but can't be fully monetized as the benefits cannot be realized or monetized). There are limited hedging opportunities and higher costs of doing so with collateral. All of this has caused annual ERM balances for the last three years (2021-2023) to result in surcharge of $16M / $49M / $24M, respectively.

- **Forecast Error Adjustment (Section III.B., below)**

4 The adjustment is really just a part of an overall power supply adjustment that has been isolated for closer examination. It is necessary to set the "baseline" correctly, otherwise the ERM does not function as intended. Aurora modeling, standing alone, cannot reflect all of the market transformation. In a word, Aurora, itself, greatly overvalues thermal assets in a changed market. The adjustment is "known and measurable" (using known deltas between authorized and actual costs reviewed in ERM process). It captures inherent "offsets" as part of the process because it looks at the entirety of differences between authorized and actual NPE. It is based on evidence of contracts and other entries.

5 The Company has "rerun" the model to update all components and reflect certain adjustments of parties. The "forecast error adj" is reduced from $65.8M to $29.7M (a reduction in system NPE from $175.1M to $119M). This is based on updated market prices and contracts. As

noted, the Company has used actual 2021-2023 ERM variances (versus estimates) to overcome concerns over "known and measurable" adjustments.

6 Finally, it is well to remember that the Commission has long recognized, in any event, the need to employ reasonable assumptions in deriving NPE (see 2020 Policy Statement discussed below), e.g., hydro assumptions (median water), prices based on three months of forward prices; power plant operating performance (5 year average); and loads are "weather-normalized."

7 In sum, the Commission should not subject "forecast error" to a standard greater than other assumptions driving NPE. "Forecast error" is no more or less known than many other assumptions already making up the Company's NPE value.

- **Energy Recovery Mechanism (ERM) (Section III.C., below)**

8 Higher costs absorbed through ERM have reduced earnings significantly (2021-2024), and impacted Company cash flows, impacting important credit metrics. Markets have changed dramatically, events are outside of Company control, and tools to manage risk (hedging) are increasingly limited. Avista is being penalized for events well beyond its control.

9 The Commission should recognize that Avista is different than PacifiCorp and the prior decision in the PacifiCorp case should not govern any ERM modifications proposed here. Avista has greater exposure to volatility with a market surplus that is much greater than PacifiCorp and its ability to absorb financial impacts is less. A ten-fold increase in the forecasted thermal value of Avista's fleet won't materialize because of collapsing values between forwards and spot market prices. There is also a loss of forward hedging opportunities to lock in future value. In sum, opportunities for beneficial sales transactions are much less; the market has fundamentally changed.

10 Finally, in comparing the size of the "deadband" with PacifiCorp, it should be recognized that Avista's sharing of "deviations" are two times that of PacifiCorp. PacifiCorp with a $4M deadband also has a market capitalization that is four and one-half times that of Avista; what may serve as an "incentive" for PacifiCorp has become punitive for Avista.

- **<u>Two-Year Rate Plan (Section I.D., below)</u>**

11 Staff argues that there is a burden associated with processing a two year rate plan. Staff's proposal to ignore Rate Year 2 (RY2) overlooks the fact that $54.2M of the $69.3M RY2 request on rebuttal is simply removal of Colstrip. The remaining $15M is mostly a continuation of capital and expense items already reviewed in Rate Year 1 (RY1). Staff would needlessly substitute <u>additional</u> process for the later removal of Colstrip costs. Moreover, a one-year plan would cause Avista to lose 9 to 12 months of additional rate relief that would be covered in RY2, and Avista would then absorb 73 basis points and 77 basis points of lost Return on Equity (ROE) for electric and gas, respectively. Said differently, such a result would be, in effect, the Commission ordering zero rate relief for Rate Year 2. Finally, and perhaps most significantly, it represents a wholesale "retreat" from progress made under the MYRP legislation. Nor is it necessary to synchronize with the Company's Clean Energy Implementation Plan (CEIP), as argued by Staff, because no material compliance costs are included in this Rate Plan.

- **<u>Use of "Portfolio" Approach in Review of Provisional Capital (Section V.A., below)</u>**

12 AWEC's proposal to review "provisional" capital on a project-by-project basis is inconsistent with the "portfolio" approach used in the provisional capital review process in prior MYRPs of Avista and PSE. It is also antithetical to the necessary "flexibility" required in a MYRP to make it workable. Only AWEC suggests a project-by-project review in the subsequent capital review process. Staff is also opposed, recognizing the need for "flexibility" during the course of a

2 to 4 year rate plan to incorporate changes, where necessary, in the scope and direction of ongoing capital spending. A six-month review period will suffice for the additional capital review, especially given the fact that only a very small percent (1%)[1] of overall capital transferred-to-plant in RY1 is "new" and not previously reviewed as part of the prior general rate case (GRC). "Flexibility" to address changed circumstances is a "must" for any type of MYRP to function. Absent such flexibility, there would simply be no reason for any utility in Washington to file for anything but a Two-Year Rate Plan; there would simply be too much risk for the utility.

13 Taken together, or viewed separately, the adoption of only a one-year Rate Plan and the rejection of the "portfolio" approach to ongoing review of "provisional" capital, will undermine the very purpose of the MYRP legislation. It will simply have become unworkable.

I. <u>INTRODUCTION - OVERVIEW OF CASE</u>

A. <u>Current Financial Condition</u>.

14 As explained by Avista Witness Christie, the cost pressures from inflation and rising interest rates have negatively impacted Avista: Over the last two years, these cost headwinds have significantly hurt Avista's financial performance, balance sheet strength, and credit metrics. In addition, another major headwind impacting Avista's financial performance is higher resource costs as a result of poor hydro performance in 2022, 2023, and now again in 2024. These past two and a half years are among the worst hydro years on record, and with Avista being approximately 50% hydro-based from a resource perspective, our financial performance has suffered.[2] The higher resource costs absorbed through the ERM reduced earnings significantly in 2022, 2023 and have put significant pressure on our results thus far in 2024.[3]

[1] This is also true on an actual Washington Net Plant after ADFIT Basis (level of plant approved) versus that authorized by the Commission in RY1 (2023) of 0.9%.
[2] Christie, Exh. KJC-2:17 – 3:3.
[3] *Ibid*.

15 From a rating agency perspective, Avista's credit remains on "negative outlook" from Standard and Poor's (S&P), due to Avista's weakening financial performance causing our metrics to fall below their downgrade thresholds in 2022 and 2023 because of inflation, rising interest rates, and regulatory lag. In addition to those items, wholesale energy markets have been extremely volatile. S&P has signaled they will downgrade Avista's credit rating if its credit metrics do not improve above their downgrade threshold in the very near future. The Company's continued weak financial performance, and deterioration in credit metrics highlight again the challenging environment in which we are operating and the importance of supportive regulation. Ultimately, S&P concludes:[4]

> The industry-wide negative outlook reflects rising physical risks as well as financial measures, which are weakening due to rising capital spending and cash flow deficits that are not funded in a sufficiently credit supportive manner. Furthermore, much of the industry operates with minimal financial cushion from their downgrade threshold. This increases the susceptibility to a downgrade if negative events occur beyond our base case. (Emphasis added)

The Commission's support of this two-year Rate Plan, with the necessary rate relief requested, including power supply adjustments and modifications to the ERM, will be both credit-supportive and supportive in the equity markets as the Company acquires funds to continue its work on behalf of its customers. As testified to by Mr. Christie, "[p]rudent costs not recovered are – are a factor that the rating agencies consider and certainly could lead to a downgrade."[5]

16 Mr. Christie was cross-examined by Public Counsel about the Company's dividend policy, including its history of increasing the dividend over prior years, to which Mr. Christie reaffirmed that the Company's "dividend policy" and "dividend growth rate is in line with our regional peers."[6] He went on to explain why this is important:

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4 *Id*. at 2:18 – 3:15.
5 TR at 142:8-10.
6 TR at 142:13-14.

> Investors take into consideration the number of factors when it comes to value creation and how they perceive Avista stock. There's really two parts: our performance, which leads to stock price change, and dividends. And with poorer performance over the last couple of years or under-recovery, dividend has been supportive but only really helping us tread water with our peers. We need to be able to compete for capital with our peers.[7]

17 Mr. Christie, who as CFO regularly interacts with rating agencies, also emphasized the importance of an effectively-structured ERM in meeting the cash-flow metrics underlying the Company's ratings:

> I regularly interact with the rating agencies. I feel like I have a pretty good understanding of how they look at all the factors related to Avista cash flow being the one we talked about at length, and I think we've got that well covered.
>
> One thing related to cash flow is the energy recovery mechanism. And to the extent that – with markets outside our control or factors inside the power markets that we cannot control, the fundamental shifts that have taken place – that it could lead to – the mechanism itself could lead to cash flow metrics falling well below the threshold.[8]

B. <u>Drivers of Rate Request</u>.

18 The increase in overall costs to serve customers is driven primarily by the continuing need to replace and upgrade the facilities and technology the Company uses every day to serve its customers, while revenue growth remains low. As discussed by Company Witness Schultz (Exh. KJS-1T, at 17-18), the primary factor driving the Company's electric and natural gas revenue requirements in RY1 and RY2 is an increase in net plant investment.[9] In addition, net power supply expense also contributes significantly to the incremental electric revenue requirements over the two-year Rate Plan. Other changes impacting the Company's revenue requirement relate to regulatory amortizations and increases in distribution, operations and maintenance (O&M), and

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7 TR at 142:17-25.

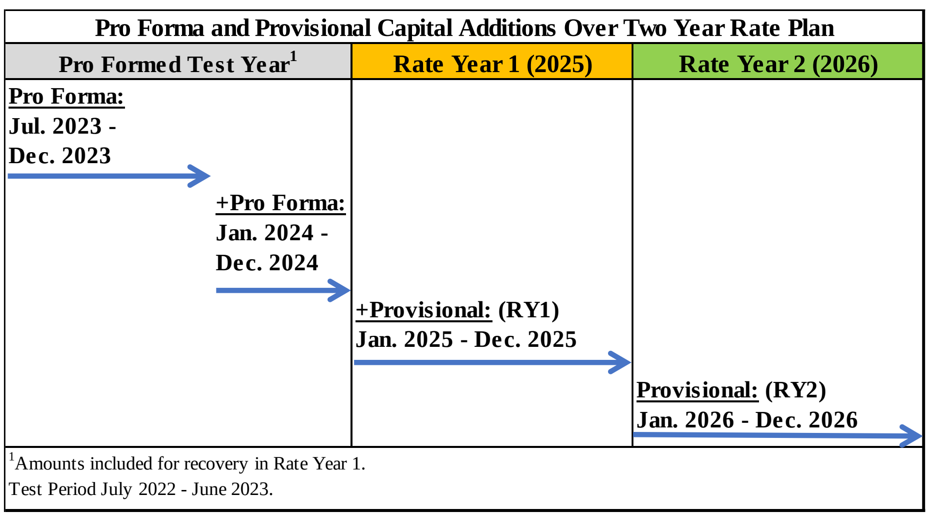
8 TR at 143:23 – 144:11.

9 The Company typically has approximately 120 Business Cases completed on an annual basis. Over the past five years, this amounted to roughly $430 million of annual capital spending (system). This system-level investment has increased to $500 million in 2024, $525 million in 2025 and $575 million in 2026. (Christie, Exh. KJC-4T)

administrative and general (A&G) expenses for both electric and natural gas operations, compared to currently authorized levels.

19 The Company has included total electric and natural gas pro forma and provisional capital additions planned to transfer to plant between July 1, 2023 through December 31, 2025 for RY1, and January 1, 2026 through December 31, 2026 for RY2. The Company pro formed capital additions for the period July 1, 2023 through December 31, 2023. Capital additions for the period January 1, 2024 through December 31, 2026 are included as "provisional" and are subject to further review through the Company's proposed annual Provisional Capital Reporting process, as used in the past. Illustration No. 1 below, excerpted from Ms. Schultz's testimony, provides a simple schematic of inclusion of capital addition(s) during the Two-Year Rate Plan.[10]

Illustration No. 1 – Capital Additions Included in Two-Year Rate Plan



On rebuttal, Company Witness Ms. Andrews revises the labeling of 2024 capital additions as "provisional."[11]

C. Revisions to Rate Request on Rebuttal.

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[10] Schultz, Exh. KJS-1T, at 13.
[11] Andrew, Exh. EMA-6T, at 11.

20 The Company's proposed revenue requirement on rebuttal is $42.9 million (6.7% on a billed basis) for electric and $16.8 million (5.8% on a billed basis) for natural gas for RY1. For RY2, the Company's proposed revenue requirement is $69.3 million (6.5% on a billed basis after taking into account the proposed reduction in electric Schedule 99 reflecting certain reductions related to Colstrip) for electric, and $4.0 million (1.3% on a billed basis) for natural gas.[12] The main driver for RY2 is the removal of Colstrip from base rates, required by the end of December 2025.

21 Approval of the recommended adjustments proposed by Staff, Public Counsel, or AWEC would result in a ROE in RY1 of over 130 to 310 basis points for electric and 40 to 240 basis points for natural gas, under that currently authorized (9.4%). For RY2, the results are even worse, given Staff did not support a second rate year. As a result, electric results would be 120 to 570 basis points lower than the presently authorized 9.4%, and 70 to 270 basis points lower for natural gas.[13]

22 Nevertheless, after reviewing the positions of the parties in their cases, and making necessary revisions based on that review and reflecting the most current information available, Avista has lowered its overall revenue requirement on rebuttal. The primary revision is related to power supply expense in RY1, and the treatment of Colstrip in RY2. Regarding power supply, as discussed by Company witness Mr. Kalich on rebuttal,[14] the Company has rerun the pro forma power supply model, updated the usual components and accepted certain modifications

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12 This compares to an originally proposed revenue requirement of $77.1M for electric in RY1 and $78.1M for RY2. For natural gas, the Company had originally proposed $17.3M for RY1 and $4.6M for RY2.

13 Christie, Exh. KJC-4T at 11:19 – 12:4. This, of course, assumes that everything goes as expected and costs occur as anticipated in the Company's Two-Year Rate Plan, and without events beyond the Company's control. Since the filing of the Company's rebuttal, Staff revised its proposed revenue requirement upward, reducing somewhat the impact of its proposals on the basis point shortfall from the currently-authorized ROE. The resulting ROE would still remain well below authorized levels.

14 Kalich, Exh. CGK-7T at 2:14 - 4:15.

recommended by the parties. The Company has also updated EIM benefits to reflect a higher level of benefits.[15] For RY2, the initial estimate of the removal of $59.5 million of Colstrip costs is now $54.2 million, based on the most recent re-run of power supply costs, and that is reflected in RY2 electric revenue requirements.[16]

23 The Company, on rebuttal, also modified the structure of the ERM, after reviewing the testimony of Staff. While Avista initially proposed a 95/5 sharing mechanism for the ERM, upon review of Staff's testimony, it is willing to accept a 90/10 sharing of costs and benefits, but with a slightly modified "deadband" versus that proposed by Staff. For reasons discussed by Mr. Kalich,[17] the Company supports an <u>asymmetric</u> deadband, whereby when power supply costs are higher than authorized (i.e., the surcharge position), the Company would absorb $2.5 million before the 90/10 sharing. Likewise when actual power supply costs are lower than authorized, the Company would only retain $2 million, before sharing 90/10 with customers. For its part, Staff was attempting to arrive at a deadband commensurate with what it had proposed for PacifiCorp ($4 million) but ratioed downward to $3 million to reflect the relative size of Avista compared to PacifiCorp.[18]

24 The Company is making several other revisions to its power supply proposal after reviewing the testimony of other parties:[19]

- The Company has rerun the Power Supply Model, updating all of the usual components such as wholesale natural gas and power prices, new and short-term incremental contracts, non-gas fuel prices, and adopting certain of the positions of the parties that were discussed in their testimonies (see Mr. Kalich's testimony Exh. CGK-7T for a description of the specific changes).

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15 *Id.* at 13:3-10.
16 *Id.* at 13:16-18.
17 Kalich, Exh. CGK-7T at 3:5-17.
18 Avista believes that a more commensurate reduction to the proposed asymmetrical deadband of $2.5 and $2.0 million is justified based on relative size metrics of Avista and PacifiCorp and its corresponding ability to absorb the "deadband" in a way that would still be meaningful without being punitive. (*Id.* at 14:7-18)
19 Kalich, Exh. CGK-7T at 17:1-31.

- The "forecast error adjustment" will remain but is reduced from $65.8 million to $29.7 million (both values on a system basis) using an average of actual 2021-2023 ERM variances, to address concerns expressed by the parties. Avista has revisited its NPE estimate to reflect updated market prices and contracts, and to show the impact of a modified forecast error adjustment. The Company believes these changes offer a net power expense more closely aligned with what should be included in final rates based on updated information and the concerns of the parties. With the update the Company is not proposing further updates during the Rate Plan. The Company updated wholesale electricity and natural gas prices to a 3-month average of forward for the period ending July 15, 2024. It also updated short-term contracts as of July 15, 2024.

- Colstrip is removed from the 2026 net power supply expense based on its 2025 net value (i.e., market values less fuel). No further power supply updates to 2026 would then be necessary.

- The incremental value for EIM is now set at $6.6 million (system) and not $5.5 million (system), after correcting for errors.

D. Multi-Year Rate Plan.

25 Staff Witness Erdahl recommends the rejection of Avista's proposed Two-Year Rate Plan.[20] Staff relies on two reasons for the rejection of the Rate Plan – regulatory burden, and the need to synchronize with CEIP filings. As it relates to regulatory burden, Staff's position falls well short on several fronts. First, while the Company's originally-filed revenue requirement for RY2 was sizeable at $78.1 million, almost $60 million of that amount is related to the removal of Colstrip from base rates, as required by Washington State law. Staff, however, contemplates even more administrative burden with yet another required filing later to accomplish what could easily be accomplished now in this proceeding.

26 As for the remaining $15 million requested for RY2 on rebuttal, the adjustments are similar to those for RY1 (and which were reviewed by Staff). These include incremental capital additions, increases in labor costs, certain expense items, etc. Again, Staff already reviewed these items to

[20] Erdahl, Exh. BAE-1T, at 7.

develop its first year revenue requirement and could have simply extended their work into RY2 with little additional effort.[21]

27 Moreover, the effect of Staff's proposal on Avista would be untenable. As explained by Mr. Christie, Avista would not be able to compile updated test year data and prepare the next necessary general rate filing in the immediate aftermath of a Commission order in December 2024, if the Commission adopted only one-year rate change, without losing 9-12 months of additional rate relief (now covered by the second year of Avista's two-year Rate Plan).[22] That revenue shortfall would have significant financial repercussions, including impacts on credit metrics. As Mr. Christie avers: "There is no way to cut ourselves to earning our authorized under such a scenario. Essentially, Avista would be a casualty of Staff's unwillingness to now process the proposed two-year Rate Plan."[23] In the end, Staff's proposal represents a "retreat" from the progress made in recent years in optimizing the regulatory process.[24]

28 Staff Witness Erdahl also believes that a multiyear rate plan should be timed with CEIPs.[25] But the facts of this case undermine Staff's very arguments because there are no meaningful investments or costs of compliance related to the CEIP included in this case (other than those that were contemplated in Avista's last CEIP).[26]/[27]

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21 Christie, Exh. KJC-4T at 23:15-20.

22 Rate cases take a significant amount of time and effort to create, which would lead to significant lag in rate relief (especially if further tied to a CEIP which would not be filed until October 2025).

23 *Id.* at 24:15-17.

24 *Id.* at 25:1-2.

25 Erdahl, Exh. BAE-1T at 7. RCW 80.28.425(9) states that multiyear rate plans should be aligned "to the extent practical." In this case, however, there are no CEIP costs of compliance to be "aligned."

26 The Company recently issued its Draft Preferred Resource Strategy for its 2025 Electric IRP. For the State of Washington, no new resources are necessary to serve customers until at least 2029. So, even if one were to imagine that the next CEIP would have investments or significant costs of compliance that lend itself towards a review in a similarly-timed general rate case, that would not be the case in 2025. (Christie, Exh. KJC-4T at 26:4-20)

27 During the hearing, Mr. Bonfield testified:

29 If the Commission were to not approve a second year rate increase now, the financial impact to the Company would be significant. Assuming the Commission would not allow Avista to file its next Two-Year Rate Plan until it files its 2025 CEIP, the Company would absorb almost 73 basis points of lost ROE for electric operations, and 77 basis points ROE for natural gas.[28] "That is a significant reduction in earnings opportunity for the Company that it simply would not be able to make up and have any opportunity to earn its allowed return," as testified to by Mr. Christie.[29] The implications from a credit and equity perspective would be "extremely negative."[30]

II. COST OF CAPITAL

A. Cost of Debt/Capital Structure.

AVISTA CORPORATION
Proposed Cost of Capital
December 31, 2025

	Percent of Total Capital	Cost	Component Cost
Total Debt	51.5%	4.99%	2.57%
Common Equity	48.5%	10.40%	5.04%
Total	100.0%		**7.61%**

The proposed cost of debt and capital structure are not at issue.

B. Cost of Equity.

So there are no costs – what I would call material costs that were happening during the course of this upcoming rate plan, if approved by the Commission, and there are no resource additions that we're seeking to defer within that approved deferral mechanism.

Q: So what, if anything, does that have to say about whether the Commission should approve a one- or two-year rate plan based on synchronizing with CEIP?

In my opinion, it has no bearing on the decision of the one- or two-year rate plan. They're completely separate from one another. As I mentioned, those incremental costs to implement the CEIP were – many of them are one-time in nature. There were a limited amount that were ongoing. But they weren't for resources – resource additions, which are obviously much larger in scale. So I don't see that they're related to each other. And rather, I would say they're mutually exclusive – that the rate plan proposed in this case isn't reflective or shouldn't be held up because of the small amount of costs we're deferring to implement a CEIP. (TR at 336:1-21)

28 Using the Company's rebuttal RY2 revenue requirements for electric (excluding Colstrip) and natural gas. Christie, Exh. KJC-4T at 27:6-8.

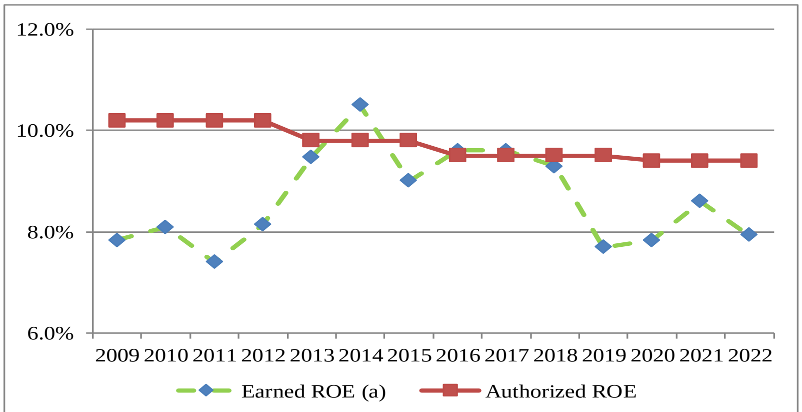
29 *Id.* at 27:7-10.

30 *Id.* at 27:14-16.

30 By way of context, Avista's earned ROE has fallen below its authorized ROE in 11 of the past 14 years, in many cases by a substantial margin, especially without the means to otherwise address regulatory lag since 2018, with an attrition adjustment.[31] This is illustrated below:

FIGURE No. 1

ACTUAL VS. AUTHORIZED ROE[32]



(a) Normalized (Commission basis).

31 Mr. Parcell (Staff) recommends a ROE of 9.50% for Avista,[33] while Mr. Garrett (Public Counsel) recommends a ROE of 8.50%[34] and Dr. Kaufman (AWEC) recommends a ROE of 9.25%.[35] Ms. Perry (Walmart) did not recommend a specific ROE; rather, she recommended that the Commission consider customer impacts, ROEs awarded to other Washington utilities, as well as ROEs awarded by other state regulatory commissions.

32 As summarized by Company Witness McKenzie, the ROE recommendations of the other Witnesses fall well below a fair and reasonable level for the Company's electric and gas operations:[36]

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31 Moody's noted that "the lag in cash flow recovery and limited revenue increases have pressured Avista's credit metrics particularly during a time when the sector faced material headwinds from higher natural gas prices and other cost pressures." (Moody's Investors Service, *Avista Corp., update to credit analysis*, Credit Opinion (Aug. 16, 2023)). Similarly, S&P reported the prospect of lowering Avista's ratings over the next 12 to 24 months if financial metrics are pressured by "regulatory lag." (S&P Global Ratings, *Avista Corp.*, Ratings Direct, Ratings Score Snapshot (Dec. 8, 2023)). (Christie, Exh. KJC-4T at 22:17-19)

32 Christie, Exh. KJC-4T at 22:1-12.

33 Parcell, Exh. DCP-1T at 6:2.

34 Garrett, Exh. DJG-1T at 4:8.

35 Kaufman, Exh.LDK-1T at 21:4-5.

36 McKenzie, Exh. AMM-15T at 2:7 – 3:3.

- The Other Witnesses' ROE recommendations fall below accepted benchmarks:
    - Adjusting national authorized ROEs for electric utilities to reflect current capital market conditions implies an ROE of approximately **10.43%**.
    - Adjusting ROEs approved by the Commission in prior rate proceedings for increases in bond yields implies a current cost of equity of **10.43%**.
    - Adjusting Avista's current ROE to account for changes in capital costs implies a current cost of equity of approximately **10.84%**.
    - Expected earned returns for the Other Witnesses' proxy groups fall in the range of approximately **10.0% to 10.7%**.
- The Other Witnesses' ROE analyses are also undermined by errors and methodological flaws, including:
    - Failure to account for significantly higher capital costs, declining creditworthiness, and rising risk exposures, such as wildfires.
    - Errors in the specification of their proxy groups.
    - Unsupported growth rate assumptions in the application of the discounted cash flow ("DCF") model that do not reflect investors' expectations.
    - Capital Asset Pricing Model ("CAPM") studies that rely on historic backward-looking inputs that are not consistent with this method.
    - Subjective and unsupported beta calculations.
    - Failure to account for the impact of firm size in applying the CAPM.
    - Arbitrary and unsupported exclusion of "outliers" and model results.

Mr. McKenzie then addresses the particulars of recommendations by each of the other ROE witnesses:

1. <u>Staff Witness Parcell.</u>

33 There are key deficiencies in his quantitative applications that lead to a significant downward bias in conclusions. Mr. McKenzie demonstrates that:[37]

[37] McKenzie, Exh. AMM-15T at 2:7 – 3:3.

- The screening criteria adopted by Mr. Parcell to arrive at his proxy group are arbitrary, unnecessarily restrict the size of the group, and undermine the reliability of his analyses.

- The flaws in Mr. Parcell's DCF analysis include reliance on historical data; including growth rates based on dividends and book value; his decision to average individual growth rates together and then compute a single DCF estimate for each company; computational shortcomings in his retention growth calculation; and subjectively excluding a 10.6% DCF result as an "outlier," while retaining values in the 7% range.

- Mr. Parcell's CAPM analysis also contains numerous flaws, most notably his reliance on historical data when the ROE estimation process is clearly forward-looking; adopting an improper methodology to calculate his historic market risk premium ("MRP"); reference to geometric means, which will always bias results downward; failure to account for the impact of firm size; and subjectively excluding a 10.7% CAPM result as an "outlier."

- Mr. Parcell's Comparable Earnings ("CE") approach also contains significant shortcomings due primarily to his repeated fault of relying on historical data in a process that is forward-looking; his problematic consideration of market-to-book ("M/B") ratios in his CE analysis, and his failure to apply an essential mid-year adjustment factor.

- Mr. Parcell's risk premium approach is undermined by subjective bias due to his selective exclusion of available data.

- Finally, Avista should be offered an opportunity to recover flotation costs, which are a legitimate expense incurred to provide the equity capital.

2. <u>Public Counsel Witness Garrett.</u>

34 Mr. Garrett's 8.50% ROE is extreme and the Commission should reject his conclusions and recommendations in their entirety as testified to by Mr. McKenzie,[38] who demonstrates that:

- Mr. Garrett's DCF approach is compromised because he ignores projected earnings growth rates, which are widely and recognized as a superior basis to apply the DCF model; he relies on a "sustainable" growth DCF model that wrongly assumes investors anticipate every firm in the electric utility industry to mimic a long-term growth forecast for gross domestic product ("GDP"); he fails to screen his DCF result to remove illogical estimates.

[38] McKenzie, Exh. AMM-15T at 4:1-17.

- PC witness Garrett's CAPM application is compromised due to unreliable, illogical, and undocumented inputs, reliance on historical data that is inconsistent with the assumptions of this method, and failure to incorporate the size adjustment.

- Mr. Garrett's suggestion that Avista's capital structure would distinguish Avista's overall investment risk from other electric utilities is incorrect, and his "Hamada" adjustment to his CAPM results is deeply flawed and should be given no weight.

- PC witness Garrett's analysis is also undermined by his failure to apply the risk premium approach, which is a widely recognized methodology.

35 Mr. Garrett's 8.50% cost of equity estimate for Avista is not credible and should be dismissed. An authorized ROE of 8.50% for the Company would be extreme and punitive. Notwithstanding the fact that bond yields remain elevated,[39] his recommendation is 130 basis points <u>below</u> the average allowed ROE for other vertically integrated electric utilities in 2023 reported by RRA.[40] Such an outcome would fall well below the returns available from comparable-risk investments and undermine the financial integrity of the Company, conditions that violate the *Hope* and *Bluefield* regulatory standards.

3. <u>AWEC Witness Kaufman</u>.

36 Dr. Kaufman's suggestion that Avista's ROE should be reduced from 9.40% to 9.25% makes no economic sense, in light of the objective evidence that investors' required rate of return has <u>increased</u> significantly since the Company's last litigated rate proceeding. The testimony of Mr. McKenzie[41] demonstrates that:

- The hodge-podge of return benchmarks cited by Dr. Kaufman are nonsensical and provide no meaningful basis to evaluate a fair ROE for Avista.

- There is no support for the assumptions of Dr. Kaufman's three-stage DCF model, which has no demonstrable connection to the expectations of investors.

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39 Baa utility bond yields averaged 5.84% in 2023 and 5.85% in the first six months of 2024. (*Id.* at 78, fn. 89)

40 S&P Global Market Intelligence, *Major energy rate case decisions in the US—January-December 2023*, RRA Regulatory Focus (Feb. 6, 2024). (McKenzie, Exh. AMM-15T at 78)

41 McKenzie, Exh. AMM-15T at 4:20-25.

- Like PC witness Garrett, Dr. Kaufman's constant growth DCF application is based on the misguided notion that investors expect growth for all utilities to converge to a long-term forecast of growth in GDP, which is the same fundamental flaw that undermines AWEC's three-stage DCF analysis.

- The Commission should reject Dr. Kaufman's subjective and results-oriented beta calculations, which run counter to those published by reputable source relied on be investors, subjectively ignores representative data, and incorporate unsupported adjustments.

- The two MRPs Dr. Kaufman used to apply the CAPM either lack any clear foundation or were based on illogical modifications to Mr. McKenzie's methodology, which was predicated on the approach adopted by the Federal Energy Regulatory Commission ("FERC"). In addition, Dr. Kaufman's CAPM results are downward-biased because he fails to account for the implications of firm size.

37 Trends in bond yields provide <u>objective evidence</u> that investors' required rate of return has increased significantly since Avista's current 9.40% ROE was established. The fact that Dr. Kaufman is proposing to decrease Avista's ROE when capital costs have demonstrably increased shows that his recommendation is divorced from fundamental financial principles and should be given no weight.[42]

4. <u>Walmart Witness Perry</u>.

38 While Ms. Perry does not conduct any analysis or provide an explicit ROE recommendation, she expresses concern over Avista's ROE request based on a comparison with historical allowed ROEs and consideration of customer impacts. Mr. McKenzie's rebuttal testimony demonstrates that:[43]

- Comparisons with historical allowed ROEs, such as those cited by Ms. Perry, are overly simplistic and fail to account for the significant increase in long-term capital costs documented by objective capital market data.

- The cost of equity is established in competitive capital markets, and Ms. Perry's suggestion that Avista's ROE might be artificially suppressed to minimize customer impacts ignores

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[42] *Id.* at 4:6-10.
[43] *Id.* at 5:18-29.

the requirements of regulatory standards, as well as the long-term harm that can result if investor confidence is undermined.

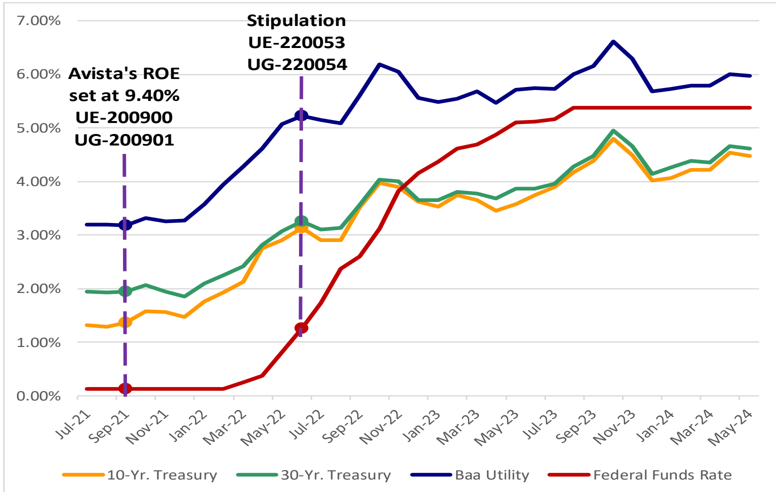
39 Taken as a whole, and as illustrated in Figure AMM-R1 of Mr. McKenzie's testimony,[44] the 8.50% to 9.50% ROE recommendations of the Other Witnesses fall approximately 93 to 193 basis points below national average authorized ROEs, once adjusted for current interest rates. This ROE disparity is even more evident when considering that utility bond yields have increased approximately 250 basis points since the Commission approved an ROE of 9.40% for Avista in its last litigated rate proceeding.[45] These benchmarks illustrate that the Other Witnesses' ROE recommendations violate the economic and regulatory standards underlying a fair ROE, while confirming the reasonableness of the 10.40% ROE requested by Avista.

5. Benchmarks for Changes in Capital Cost.

40 Trends in bond yields since the Stipulation in Avista's last rate proceeding and the Commission's order in Dockets UE-200900 and UG-200901 document a substantial increase in the returns on long-term capital demanded by investors. The key interest rate benchmarks cited by the Other Witnesses indicate that investors' required return on debt securities has increased an average of 170 basis points from September 2021 to June 2022, and another 99 basis points to June 2024. The midpoint of the Federal Reserve's target range for the Federal Funds rate has increased 113 basis points from September 2021 to June 2022, and another 413 basis points to June 2024.[46] The trends in bond yields are illustrated in Figure AMM-R2 below:[47]

[44] *Id.* at *6:3-7.*
[45] McKenzie, Exh. AMM-15T at 6:9-12.
[46] *Id.* at 9:1-8.
[47] *Id*. at 10:1-6.

FIGURE AMM-R2
BOND YIELD TRENDS



Source: https://fred.stlouisfed.org/; Moody's Investors Service.

As is evidenced in Figure AMM-R2, bond yields have increased markedly since the 9.40% ROE was established by the Commission in September 2021. The upward shift in capital costs that began in 2022 has been swift and dramatic.[48] While it took 22 <u>years</u> for interest rates to fall by one-half,[49] the Baa utility bond yield almost doubled in just 22 <u>months</u>.[50]

41 Public Counsel makes much of the fact that the Federal funds rate was recently lowered by 50 basis points. Company Witness Mackenzie, however, was quick to remind Public Counsel that: “the current triple-B utility bond yield is about 5.4% . That’s still over 220 basis points, I think, higher than when the Commission set Avista’s ROE at 9 and a half min its last litigated case.”[51]

42 Mr. McKenzie addressed the increasing challenges faced by electric and gas utilities,[52] with S&P revising its outlook on the utility sector to “negative” in February 2024, noting that, “Credit quality for North American investor-owned regulated utilities has weakened over the past four

48 *Id.* at 13:1-8.
49 In 1990 the average yield on Baa utility bonds was 10.06%. It wasn’t until 2012 that the average yield fell below 5.03%. (*Id.* at 13, n.16)
50 During December 2021, the yield on Baa utility bonds averaged 3.27%. Over the six months ending December 2023, monthly average bond yields ranged from 5.68% to 6.61%. (*Id.* at 13, n.17)
51 TR at 160:5-9.
52 McKenzie, Exh. AMM-15T at 15:1-10.

years, with downgrades outpacing upgrades by more than three times.[53] Similarly, Fitch concluded that its "deteriorating outlook" for the utility sector "reflects continuing macroeconomic headwinds and elevated capex that are putting pressure on credit metrics in the high-cost funding environment."[54] Meanwhile, Avista's credit ratings have remained unchanged, with S&P currently assigning a "negative" outlook to the Company, warning investors of a potential downgrade to its BBB rating.[55] Avista's ongoing exposure to wildfires heightens investors' overall risk profile and the Company's need to buttress its financial strength.[56]

43 In summary, the other witnesses do not address the implications of declining utility credit ratings, increased financial pressures, or the heightened risk posed by wildfires. Nor do their ROE recommendations reflect the significant upward trend in capital costs since Avista's last litigated rate proceeding. Mr. Parcell's 9.50% recommendation reflects a meager 10 basis point increase in Avista's ROE, while the recommendations of Dr. Kaufman and Mr. Garrett imply a *reduction* in Avista's ROE of 15 and 90 basis points, respectively. With Baa utility bond yields now over 260 basis points higher than they were in September 2021, it stands to reason that the Company's ROE is now substantially higher.[57]/[58]

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53 S&P Global Ratings, *Rising Risks: Outlook For North American Investor-Owned Regulated Utilities Weakens*, Comments (Feb. 14, 2024). (*Id*. at 15, n.25)

54 Fitch Ratings, Inc., *North American Utilities, Power & Gas Outlook 2024* (Dec. 6, 2023). (*Id*. at 15, n.24)

55 S&P noted that "Avista's weakening financial performance will cause its metrics to fall below our downgrade thresholds because of inflation, rising interest rates, and regulatory lag." S&P Global Ratings, *Avista Corp.'s Rising Risk Of Wildfires Is Negative For Credit Quality*, RatingsDirect (Aug. 22, 2023). (*Id*. at 15, n.25)

56 *Id.* at 16:4-10.

57 *Id.* at 24:1-6.

58 Mr. McKenzie calculated what Avista's currently authorized ROE of 9.40% would equate to in today's capital markets. (McKenzie, Exh. AMM-5T at 24:19 – 25:9) After adjusting for current financial market conditions, Avista's currently approved ROE of 9.40%, which was authorized in September 2021, would be substantially higher. The average yield on Baa utility bonds during Avista's last rate proceeding was 3.33%, and it is now 5.83%. Adding the adjusted risk premium of 5.01% to the average Baa utility bond yield in June 2024 of 5.83% <u>results in an implied cost of equity of 10.84% for Avista in today's capital markets</u>. This benchmark calculation supports Avista's 10.40% ROE request.

44 Nor should the Commission accept Mr. Parcell's appeal to "gradualism." Mr. Parcell's general appeal to "gradualism" provides no logical support for his 9.50% ROE recommendation. Considering that utility bond yields are now about 260 basis points higher than when Avista's existing ROE of 9.40% was last approved by the Commission in a litigated proceeding, even a "gradual" move towards a fair ROE requires far more than a 10 basis point increase. Moreover, considering that Staff's 9.5% ROE recommendation falls below recent authorized ROEs for electric utilities, his unsupported and misguided reference to "gradualism" does not result in a reasonable ROE recommendation or address the Company's ongoing need to maintain its financial integrity and attract capital.[59]

45 Finally, Mr. Garrett submitted testimony on behalf of Public Counsel in Avista's most recent rate proceeding in Washington.[60] The Commission rejected Mr. Garrett's ROE analyses and in its December 12, 2022 Order, the Commission concluded that Mr. Garrett's recommendation "would be a shock to Avista's financial integrity and impact its ability to attract capital on reasonable terms," and that, "[u]ltimately, we find Public Counsel's analyses and recommendations unconvincing and unpersuasive because they are too speculative and unreliable."[61] As observed by Mr. McKenzie, nothing has changed that would warrant a departure from these findings.[62]

[59] McKenzie, Exh. AMM-15T at 32:17 – 33:4.
[60] Washington Utilities and Transportation Commission, Docket Nos. UE-220053, UG-220054, and UE-210854 (*Consolidated*), *Response Testimony of David J. Garrett* (Jul 29, 2022). (McKenzie, Exh. AMM-15T at 88)
[61] Order, *supra*, at para. 163.
[62] McKenzie, Exh. AMM-15T at 89:1-2.

III. POWER SUPPLY

A. Net Power Supply Expense (NPE) Derivation.

46 The Company has rerun its Power Supply Model, updating all the usual components such as wholesale natural gas and power prices, new and short-term incremental contracts, non-gas fuel prices, and adopting certain positions of the parties that were discussed in their testimonies.[63]

47 The total of the changes equals a reduction in system NPE from $175.1 million in its filed case down to $119.0 million. Table No. 1 below details the impact of each change.[64]

Table No. 1: Impacts Made by the Adjustments to Power Supply Expense

Item	$000s
Original Power Supply Expense	**175,100**
Adjustments	
Updated BPA Transmission	215
Updated Gas Transporation	95
Thermal Startup Fuel	365
Power Sale Contract	(450)
Colstrip Fuel Cost	57
Rattlesnake Flat Generation	(2,549)
Forcast Error	(36,100)
Changes to Market Prices & Contracts	(17,686)
Total Adjustments	*(56,053)*
Rebuttal Power Supply Expense	**119,047**

Mr. Kinney spoke to changing market conditions:

> (1) Market fundamentals have changed due to the reduction in the amount and availability of longer-term bilateral trades, an increasing number of wholesale transactions made in organized markets such as EIM, changing composition of the market favoring more clean resources, state emission policy, the region's resource mix transitioning to more variable resources, and a reduction in the resource adequacy of the Northwest as load growth increases and more extreme weather events occur.
>
> (2) A large forward premium now exists in the implied market heat rate (IMHR) that can overstate the operating margin of our thermal fleet in Aurora, increasing

[63] Kinney, Exh. SJK-17T at 3:7-11.
[64] *Id.* at 4:11-21.

NPE by tens of millions of dollars. The IMHR is defined as the relationship between electricity and natural gas prices.

(3) The value of our thermal fleet in reducing forecast NPE has risen ten-fold, from $15-$30 million historically, to projections in this case of over $300 million. Along with an increased value is increased risk to the Company that these values won't materialize.

(4) The market liquidity necessary to lock in thermal fleet value has substantially diminished which prevents us from monetizing what ultimately becomes the forecast error.

(5) The cost and volatility of collateral has increased resulting in higher costs associated with power supply hedging and optimization of resources when we can hedge.[65]

48 All of these changing conditions have impacted the ERM in the last three years because the "baseline" no longer reflects market conditions. The Company's annual ERM balance for the last three years (2021-2023) has resulted in large surcharges of $16.4 million, $48.8 million, and $23.9 million, respectively, illustrating that conditions have changed significantly and the ability for the Company to properly set NPE in general rate filings is more difficult based on the factors discussed above.[66]

49 Not only do these facts attest to changes mostly outside of the control of the utility and serve to support the inclusion of a forecast error to more accurately set the NPE in this case, they also support a modification of the ERM to better match the relative size of Avista and the associated risk to achieve the NPE set in rates.[67]

B. "Forecast Error" Adjustment.

50 Given significant disruptions in the power supply market, and to better capture what the evidence suggests is necessary to more accurately reflect power costs during the rate-effective period, Avista developed in its direct filing a "forecast error" adjustment.[68]

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65 *Id.* at 5:12 – 6:8.

66 *Id.* at 6:9-13.

67 *Id.* at 6:14-18.

68 It began by developing a year based on five years' worth of historical forward market prices. (Kinney, Exh. SJK-1T at 67:7-12) It then developed an "Actual Value" which valued those same portfolio components for those same

51 In the interest of full transparency on this issue, Avista separated out this feature of the pro forma power supply adjustment and called it a "forecast error adjustment,"[69] rather than attempt to integrate it within the complex Aurora model. It is well to recognize that this "forecast error adjustment" to power supply expense is really just a part of the same overall pro forma examination of power supply expense that is, itself, a regular feature of rate case filings. It is not an adjustment unrelated to the overall power supply adjustment.

52 Why does this matter? Witness Kinney explains the importance of setting a representative "baseline" for ERM purposes:

> It is important to set the "baseline" correctly (a factual determination), for at least three reasons: (1) to assure proper and timely cost recovery; (2) to convey price signals regarding changes in power costs (especially important in a market with dramatic price changes); and (3) to assure that the "risk allocation" method still produces fair results that do not unduly benefit or penalize the Company, or its customers.[70]

Getting the expected level of NPE right is therefore essential to a balanced and fair outcome of a functioning ERM (no matter how structured).[71]/[72]

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years using actual index prices and positions. The difference between the forecast and actual values for any given year yielded what it termed its "forecast error." It then averaged the annual forecast error for the five years from 2018 – 2022, to yield a forecast error of $65.8 million (system).(*Id.* at 8:6-11) This approach was modified on rebuttal, as discussed below.

69 Although characterized as a "forecast error," that may carry the wrong connotation. That "error" is really just nothing more than the difference (or delta) between the forecast value and actual value.

70 *Id.* at 9:3-7.

71 *Id.* at 9:17-21.

72 Mr. Kinney spoke to the changing landscape affecting power supply costs:

> Forecast error reflects underlying value unrepresented in other aspects of power supply modeling. Markets have changed drastically in recent years in the makeup of resources, with an increasing amount of clean energy but with a lower contribution to reliability. Also transformational are regulations around carbon in the Clean Energy Transformation Act and the Climate Commitment Act, and the manner in which how power is traded in the forward and spot marketplaces. Aurora modeling, standing alone, simply cannot reflect all these changes without some additional changes to input assumptions – changes that weren't envisioned in the Workshops or in the final agreed-to modeling methodology. Significant to this case, the Company has shown how the assumed relationship between gas and electricity prices in the forward markets relative to the spot market has drastically changed since those workshops. This is especially true with how Aurora now greatly overvalues thermal assets. (Kinney, Exh. SJK-1T at 10:8-19)

53 On rebuttal, the Company still supports an adjustment, but at a much-reduced level of $29.7 million, versus $65.8 million. The Company is proposing, on rebuttal, to modify the forecast error calculation using a simpler method, one that accounts for offsetting factors, is known and measurable, and is based on evidence such as contracts, receipts, ledger entries, or other proof that specifically identifies the dollar amounts involved with the overestimate of the value of its fleet or the resulting underestimate of its power costs, all of which were the concerns raised in the Commission's Order denying Staff's Motion to Dismiss.[73] It is also subject to full audit and verification in the annual ERM review process. Instead of calculating the adjustment to NPE based on the average annual difference of the calculated Forward (Forecast) Value and Actual Value for the five-year period between 2018-2022,[74] the Company is proposing to use the annual average of <u>actual</u> ERM variances for the past three years from 2021-2023, which best capture the changed power supply market.[75]

54 Avista Witness Kalich explained the crux of the problem, as power markets have transformed over the last few years, and into the foreseeable future:

> So we're almost entirely exposed – and that's really a key issue, a key thing that has changed in the marketplace in the last two or three or four years. We see this great value out there. We build it into rates. And then, we get to the point where we can actually transact it, buy gas and sell electricity, the price of electricity's collapsing on us.[76]

He also explained why it made sense to go back three years (and not five or ten years, etc.):

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73 Order 07 at Paragraph 83 (Dockets No. UE-240006 and UG-240007).

74 Kinney, Exh. SJK-1T at 68:7-12.

75 *Id.* at 11:16-20. Using an average of <u>actual</u> ERM balances removes any dispute about using a calculation to determine forecast error. Annual ERM balances are simply determined based on <u>actual</u> power supply expenses incurred by the Company. ERM balances are reviewed by all intervening parties and approved by the Commission annually through an established ERM review process, thus ensuring the accuracy of costs incurred. The forecast error adjustment, based on <u>actual</u> demonstrated costs, will increase or decrease NPE depending on how well the power supply methodology assumptions included in Aurora reflect actual experience. (*Id.* at 11:16 – 12:3)

76 TR at 85:3-9.

> But again, trying to reflect the future, not all of the past – and I guess what that means is – the more – most recent couple three years is, in my view, uniquely different than the years prior to that, at least a number of the years.[77]
>
> What's happens in the last three years is it's gone up to be 300 million and really reflects – and that is, to me personally, the crux of this – of this adjustment – is the fact that the market conditions really have pivoted in the last three years. And we see no reason that that won't continue until the region can build out capacity for the region.[78]

55 In Order 07 of this docket denying Staff's Motion for Partial Summary Determination, the Commission identified three areas of concern with the forecast error adjustment:

(1) "… the Company must show that the [forecast error] adjustment is: (1) known, (2) measurable, and (3) not offset by other factors,"[79]

(2) "… [a forecast error adjustment requires] sufficient evidence such as contracts, receipts, ledger entries, or other proof that specifically identifies the dollar amounts involved with the overestimate of the value of its fleet or the resulting underestimate of its power costs,"[80] and

(3) "[testimony supporting a forecast error adjustment] should provide evidence that it considered any indirect offsetting factors."[81]

56 As explained by Mr. Kinney, the revised proposal is based on three years of <u>known</u> deltas between authorized and <u>actual</u> costs based on data <u>audited</u> by the Commission and parties through our annual ERM audits. Forecast error therefore is based only on known and measurable power supply factors, including the impacts of contracts, receipts, ledger entries and other proof. <u>Offsets</u> are otherwise inherent to this data and audit exercise and are captured with certainty.[82]

57 More specifically, the <u>forecast error adjustment is known.</u> Conceptually, NPE delta is driven by variations in those costs making up NPE. Under the Company's revised proposal, the

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77 TR at 296:8-13.
78 TR at 298:14-21.
79 Order 07 at paragraph 82 (Dockets Nos. UE-240006 and UG-240007).
80 Id. at ¶ 83.
81 Id. at ¶ 84.
82 Kinney, Exh. SJK-17T at 14:17-19.

variation of components is contained within the tracked aspects of power supply in the ERM. This defines the forecast error.

58 The forecast error adjustment is also measurable because cost deltas between pro forma and actual NPE are recorded and then reviewed in our annual ERM filings. Differences from pro forma assumptions result in a measurable delta between authorized and actual NPE.

59 Finally, the forecast error adjustment captures offsets. By relying on historical differences between the entirety of authorized and actual NPE, as demonstrated in annual ERM filings, all power supply expenses (including offsets) are necessarily considered.

60 As testified to by Mr. Kinney, "forecast error is neither more nor less known than the many other assumptions making up our calculated NPE value."[83] Power Supply adjustments are a routine part of rate-setting over the years and involve reasonable pro forma assumptions. The "forecast error" adjustment to the NPE is no more or less known and measurable than is the NPE itself.

61 Forecast Error is an actual power supply cost and is no less known and measurable than the many other aspects defining NPE such as (1) assuming median hydro, (2) using 5-year historical averages for outages, and (3) forward market prices. The Commission has long recognized its need to use assumptions and projections in deciding the power supply adjustment (as discussed below). The forecast error adjustment is simply one element of the overall NPE.[84]

62 Prior power supply workshops did not presently address all major factors the Company faces today in forecasting NPE. The workshops did not benefit from an understanding of the past few years' divergence of forward market prices from spot prices, so the agreed-upon methodology

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83 *Id.* at 15:5-16.
84 Kalich, Exh. CGK-7T at 3:19 – 4:6.

didn't address a major and expanding risk we face today. Up to the time of these workshops in 2020, the projected annual value the Company's natural gas plants to NPE had varied around $30 million. No one in the workshops anticipated the risks associated with forward markets projecting natural gas plant values exceeding $300 million a year, a value nearly three times the totality of current authorized NPE.[85] Mr. Kalich puts the adjustment into perspective in the context of the ERM:

> It is plausible that a forecast error adjustment would be unnecessary if the Company was only managing a 10% share of $30 million through the ERM and its deadbands. But managing a 10% share of more than $300 million simply is not tenable. Accordingly, some level of forecast error adjustment for the relative magnitude of the issue is essential and reflects a better estimation of NPE.[86]

63 Absent recognition of forecast error, in today's market, and under the current ERM, the Company almost certainly will continue to absorb unaccounted for additional normalized costs through the ERM during the pro forma period. In each of the past reported years, 2021-2023, NPE has exceeded the $10 million level of both deadbands. Accordingly, without an adjustment, the impact on the Company could easily exceed $7 million a year, through no fault of its own.[87]

64 Avista pro formed in assumptions to estimate future power costs, as it has with the Commission's blessing over many years. Forecast error is simply one additional factor to address aspects that were not recognized in the past but that were then less significant. With a $30 million annual gas fleet contribution to reducing NPE, a 10% variance previously may have been acceptable. Today, with the fleet's value approximating $300 million annually, a 10% variation, simply cannot be ignored. Analysis and testimony provided in the case shows that deltas can greatly exceed 10%.

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85 *Id.* at 23:1-3.
86 *Id.* at 23:3-7.
87 *Id.* at 23:10-17.

65 While future "workshops" may be appropriate to further explore how to best capture the changed dynamics of the power supply market, that does not change the need for a power supply adjustment at this time, as we set the ERM baseline for the next two years during the pendency of the Rate Plan. In the words of Mr. Kalich, "I would welcome doing both."[88] The Company cannot afford to wait. The forecast error adjustment proposed by the Company is neither less nor more known and measurable than other adjustments and assumptions made in support of defining NPE– something which is done in every rate case over the past decades. Hydro assumptions, for example, in the pro forma are based on at least two large assumptions that will not occur in the rate year: (1) generation is assumed based on median water and its (2) contribution to peak-hour loads is based on a five-year average of historical generation shape. Wholesale electricity and natural gas market prices are based on 3 months of forward market prices that are not always accurate in predicting conditions in the rate year. Power plant operating performance is based on a 5-year average of historical operations, conditions that are unlikely to be entirely accurate. Loads are based on the test year with weather-normalization assumptions that surely will not equal the actual demands served in the rate year. None of these many elements can be "known and measurable" with precision and yet they are routinely used by the Commission in arriving at a pro forma NPE in making the best attempt at arriving at a power supply pro forma adjustment. The Commission has long understood the need to arrive at some estimate of power supply costs in the rate year, irrespective of how imperfect it may be, and even though not perfectly "know and measurable."[89] Ultimately the overarching "matching principle" in ratemaking requires that foreseeable assumptions must be made.

[88] TR at 305:3.

[89] Kalich, Exh. CGK-7T at 40:6-12. *See also* Kinney re-direct examination at TR. 224-16 – 226:10.

66 Both the power supply modeling methodology and past Commission approvals of prior requests based on the assumptions driving NPE, demonstrate that reasonable assumptions and projections are necessary. It is, therefore, not appropriate to subject forecast error to a standard greater than the other assumptions driving NPE, of which it is a part.[90]

67 The Commission, in its January 31, 2020 "Policy Statement on Property That Becomes Used and Useful After Rate Effective Date" ("Policy Statement")[91] stated:

> The actual amount of the change must be also be "measurable." This has historically meant that the amount cannot be an estimate, projection, product of a budget forecast, or some similar exercise of informed judgment concerning future revenue, expense, or rate base. The Commission previously has made exceptions, such as when it considered the use of attrition adjustments and power cost modeling forecasts when determining whether rates are just, reasonable, and sufficient, pursuant to RCW 80.28.020.[92] (Emphasis added)

68 Forecast error is neither less nor more known than the many other assumptions already making up our NPE value. It should be included in our NPE used in setting base rates.[93] As observed by Company Witness Kalich:

> In its Order denying Staff's Motion, the Commission expressed concern that the forecast error adjustment would not pass muster under the "known and measurable" standard. If that were true, then the NPE pro forma adjustments used in prior rate cases would also fail the "known and measurable" test, as discussed above.[94]

69 At the end of the day, no other party to this case has presented a constructive approach to addressing the changed conditions and volatility in the energy markets. Avista has.

C. Structure of ERM.

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90 *Id.* at 40:6-12.
91 Docket U-190531.
92 (Footnote included in the text) *Wash. Utils. & Transp. Comm'n v. Avista Corp. d/b/a Avista Utils*., Docket Nos. UE-090134 & UG-090135, Order 10, 21 ¶ 49 (Dec. 22, 2009) (hereinafter "Order 10") (power cost modeling); *Wash. Utils. & Transp. Comm'n v. Avista Corp. d/b/a Avista Utils.*, Docket Nos. UE-120436 & UG-120437 (consolidated), and UE-110876 & UG-110877 (consolidated), Order 09/14, 26-28 ¶¶ 70-73 (Dec. 26, 2012) (attrition adjustment).
93 Kalich, Exh. CGK-7T at 41:1-17.
94 *Id.* at 41:18-20.

70 Because the pro forming process falls short of adequately capturing systemic changes in the volatile power markets and exposes the Company to unreasonable risk, it becomes ever-more imperative to reevaluate the risk-sharing structure of the ERM itself.

71 In support of its proposal to modify the ERM, the Company notes that: (1) markets have and are changing rapidly, (2) markets are changing in a manner that detrimentally affects the Company, (3) market changes are almost exclusively outside utility control, and 4) tools to manage market exposure (e.g., hedging) are limited and rapidly diminishing.[95]

72 Staff offers an ERM alternative with a single deadband of $3 million; retaining 90/10 (customer/Company) sharing beyond the deadband. AWEC and Public Counsel object to modifying the ERM at all, arguing that power costs have always been volatile.

73 The Company has evaluated the testimony of the parties, prepared additional analysis of similar mechanisms applicable to our peers, and now suggests further modifications to the existing ERM structure:

(1) Accept Staff's recommended 90/10 sharing (versus 95/5 Company proposal),

(2) Reduce the Staff proposed $3.0 million deadbands to $2.5 million when results are in the surcharge direction, and $2.0 million when in the rebate direction, and agree with Staff to eliminate the second asymmetrical sharing band that presently refunds 75% of surplus dollars to customers or splits equally surcharge dollars.[96]

74 In arriving at the new proposed deadband sharing levels, the Company compared the relative size of its ERM deadbands to NPE with those of peer utilities and compared our market capitalization to reflect the relative risk to its business. Table No. 2 compares statistics between UTC-regulated electric utilities and their NPE.[97]

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95 Kinney, Exh. SJK-17T at 15:19-23.
96 *Id.* at 16:6-14.
97 *Id*. at 18:1-5.

Table No. 2:
NPE Comparison Among Washington UTC-Regulated Electric Utilities

Utility	NPE ($mil)	Surcharge (Utility) Band ($mil)	Surcharge (Utility) NPE (%)	Rebate (Customer) Band ($mil)	Rebate (Customer) NPE (%)
PacifiCorp	190	7.0	3.7	8.5	4.5
Puget	950	28.5	3.0	32.0	3.4
Avista	107	7.0	6.5	8.5	7.9

Relative to NPE, the Company's sharing of deviations from authorized through the bands are about two times that of either PacifiCorp or Puget Sound Energy. This comparison demonstrates the fairness of moving to a lower sharing band for the Company.[98]

75 There is yet another relevant comparison. It is also instructive to compare how impactful the deadband is to Company operations. As an example, PacifiCorp's business has a total capitalization of $24.3 billion, nearly 4.5 times the Company's $5.5 billion capitalization. And yet, Avista's current $7 million sharing in deadbands, and the 90/10 split after the bands, is counter-intuitively, at roughly the same amount as for PacifiCorp.[99]

76 The Company's proposal on rebuttal also retains the asymmetric design component of the ERM, thereby benefiting customers to a greater extent before 90/10 sharing occurs in years where actual power supply costs are higher than authorized. In surcharge years under the proposal, the Company absorbs $2.5 million before the 90/10 sharing begins; in rebate years the Company retains $2.0 million before the 90/10 sharing begins. This aspect of our modified proposal offers customers benefits beyond even Staff's proposal.[100]

[98] *Id.* at 18:1-9.
[99] *Id.* at 18:10-17.
[100] *Id.* at 19:1-6.

77 In the recent PacifiCorp Order, Avista recognizes that the Commission rejected changes to their deadband.[101] As mentioned, the risk inherent in our ERM deadbands is, however, much more impactful to us than to PacifiCorp and our peers given our relative size.

78 Even more importantly, Avista's resource position is much different than that of PacifiCorp (or even PSE). Unlike the others, Avista is in a starkly different resource position, with much greater energy surpluses versus that of PacifiCorp. But therein lies the problem: Given market constraints, and limited opportunities, Avista is unable to "lock in" the value for the benefit of its customers (through no fault of its own). As testified to by Mr. Kalich:

> [The] facts presented by Avista . . . warrant ERM modification, including a 10 times increase in forecasted thermal fleet value unlikely to fully materialize due to collapsing values between forwards and spot market prices, the loss of forward hedging opportunities to be able to lock in future value, the impacts of CCA on costs, and that, by the Company being a price taker, it has no significant control over these outcomes.[102]

79 The Company's proposal also retains the "guardrails" desired by the Commission, keeps the customer-focused intent of the <u>asymmetry</u> present in the second band of the existing ERM (in that it continues to provide more benefits to customers in surcharge years than we receive back in rebate years), and the deadband size is adjusted to a risk level more in line with our regulated peers.[103]

80 Witness Mullins for AWEC argues that "… none of the issues Avista raises have any relevance to the ERM…power costs have always been volatile."[104] While we do agree that power costs are volatile, the magnitude of this volatility, changing aspects of our business, and the relative

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101 *Wash. Utils. & Transp. Comm'n v. PacifiCorp d/b/a Pacific Power & Light Co.*, Dockets UE-230172 & UE-210852 (Consolidated), Order 08/06, ¶ 390 (Mar. 19, 2024).

102 Kalich, CGK-7T at 3:12-17.

103 Kinney, Exh. SJK-17T at 19:24 – 20:3.

104 Mullins, Exh. BGM-1T at 60:17.

size of the sharing bands, however, support the proposed ERM modification in this case. This dramatic change in the power supply landscape has been discussed above and must be addressed.

81 While Staff's proposal is much improved from the current ERM, the Company's proposal is fair to the parties, demonstrates even more value to customers, and still retains what the Company believes is the Commission's preference to credit customers more value through the deadband when authorized recovery is surplus to experienced costs.[105] It is also important to note that the Commission has a difficult job in balancing both the forecast error adjustment and the ERM modifications. To be clear, the ERM modifications would help to alleviate the effects of modeled benefits not materializing, and to the extent they do materialize, provide protection to customers.

82 In summary, as mentioned, the facts presented by Avista warrant ERM modification, including a 10 times increase in forecasted thermal fleet value unlikely to fully materialize due to collapsing values between forwards and spot market prices, the loss of forward hedging opportunities to be able to lock in future value, the impacts of CCA on costs, and that, the Company has no significant control over these outcomes.[106]

D. Energy Imbalance Market (EIM) Benefits.

83 EIM benefits are created from 15-minute unit commitments (start-ups) and 5-minute resource dispatches based on market economics. EIM intra-hour prices afford the Company, on behalf of customers, an opportunity to vary generation modestly within the hour against a new market, accruing additional value from resources and thereby lowering overall NPE. In this case, the Company incorporated the same Aurora modeling methodology as Puget Sound Energy did to

105 Kinney, Exh. SJK-17T at 22:18 – 23:12.
106 Kalich, CGK-7T at 3:12-17.

account for the ability to dispatch resources on a sub-hourly basis. The Company, however, now estimates an EIM benefit of $6.6 million, up from $5.6 million in our initial filing.[107]

84 An adjustment should not be made to reflect CAISO's counter-factual estimate of EIM, as recommended by Witness Earle, and reduce NPE by over $20 million.[108] As explained by Mr. Kalich, Avista followed the accepted PSE approach to modeling EIM in Aurora. As such, it captured expected NPE within a 5-minute market. Any further analysis is simply to estimate the EIM share of NPE. Unlike its last case where, due to a lack of intra-hour data and EIM experience, it had to add an incremental benefit for EIM, in this case the Company has explicitly modeled an EIM future by running at 5-minute intervals. No further adjustment is necessary or appropriate.

85 Witness Earle's modeling also ignores key real-world issues. An actual electric system has a series of engineering, regulatory, environmental, and practical trading restraints that must be accounted for by running through the Aurora model. By not running his Monte Carlo analysis through Aurora, his misleading results are not constrained even by Aurora's generous dispatch logic assumptions.[109]

86 Witness Mullins recommended a reduction to NPE reflecting certain settlement charges reported by CAISO equating to $3.0 million.[110] Of Witness Mullin's $3.0 million, $2.1 million was GHG revenue the Company no longer receives.[111] Witness Wilson, in revised testimony, for

[107] Witness Earle states, "Avista's forecast methodology is fundamentally flawed and as a result systematically underestimates the value of EIM participation." (Earle, Exh. RLE-1CT at 3:15) He recommends the Commission adopt an annual value equal to twelve (12) times the average of sixteen (16) monthly CAISO-calculated reported EIM benefit values falling within a 95th percentile band of those same historical values, or $20.7 million. AWEC Witness Mullins requests a downward adjustment to NPE of $3.0 million to reflect the value of GHG payments, as well as certain CAISO cost code revenues and costs he believes are not in Aurora. (Mullins, Exh. BGM-1T at 54:12-15) Witness Wilson, through revised testimony, recommends a downward adjustment to NPE of $1.4 million. (Wilson, Exh. JDW-1TCR at 38:21)

[108] Earle, Exh. RLE-1CT at 33:7-9.

[109] Kalich, Exh. CGK-7T at 53:15-19.

[110] Mullins, Exh. BGM-1T at 54:8-15.

[111] Kalich, Exh. CGK-7T at 47:13-14.

his part, relies on CAISO "group codes" to arrive at an NPE reduction of $1.4 million.[112] The majority already are accounted for in the energy modeling of Aurora. After removing values already emulated in Aurora, the net was only an increase to NPE of $0.3 million.[113]

E. Colstrip Transmission Utilization.

87 Avista still plans to use its Montana and BPA point-to-point transmission rights after transitioning out of Colstrip ownership. Avista's last three Integrated Resource Plans (IRP) show acquisitions of wind in Montana to meet load growth and compliance requirements under the Clean Energy Transformation Act (CETA). Montana wind has a higher load factor than other wind regions and provides diversity with our existing Palouse Wind and Rattle Snake Flat facilities in Washington.[114] To facilitate the delivery of renewable resources in Montana to Avista customer load, the Company must retain its current Montana Intertie and point-to-point transmission contract rights with BPA.[115] Moreover, it is unlikely that Avista will be able to acquire new BPA transmission rights to deliver future resources, if it gives up its current capacity since new transmission facilities will need to be built.[116]

88 Holding this capacity also provides benefits to Avista customers through participation in the EIM and future Day Ahead (DA) markets. The lack of transmission capacity to other EIM and DA market participants will limit Avista's opportunities to transact in these organized markets, which significantly reduces participation benefits.

89 As explained by Mr. Kinney, and contrary to AWEC Witness Mullins testimony,[117] the value of maintaining existing transmission capacity, and even pursuing additional capacity, is

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112 Wilson, Exh. JDW-1TCR at 18:17-22. "Cost groups" are broader categories of individual EIM cost codes.
113 Kalich, Exh. CGK-7T at 48:1-2.
114 Kinney, Exh. SJK-17T at 25:12-16.
115 *Id.* at 25:20-21.
116 *Id.* at 26:6-8.
117 Mullins, Exh. BGM-1T at 57-58.

growing as available regional transmission capacity gets closer to being fully subscribed, the regional power supply in the West tightens, load growth increases, and Western organized markets expand from hourly to day-ahead operations.[118]/[119]

90 In conclusion, Avista strongly disagrees with Witness Mullins' claim that its Colstrip transmission assets will not be used and useful.[120] Avista's 2020, 2021 and 2023 IRPs showed Montana wind as a preferred renewable resource to meet future load growth and Washington State clean energy and emissions policy requirements. If Avista does not maintain its Colstrip transmission ownership, then it will significantly limit renewable resource selection and trading opportunities resulting in higher future costs to customers.[121]

F. <u>CCA Costs in Dispatch Decisions</u>.

91 The Company disagrees with Witness Wilson's original recommendation that Avista include CCA allowance costs in thermal plants dispatch.[122] Including CCA costs in dispatch was the subject of a recently-issued Policy Statement that was subsequently withdrawn. Clearly, that issue should not be before the Commission in this case, given the far-reaching implications for all participants in the region and need for a much better understanding of the implications.

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[118] Kinney, SJK-17T at 27:1-5. .

[119] If Avista is not using all of its BPA transmission associated with current Colstrip generation to deliver energy to load, then the Company can resell unused capacity to other entities on a short-term basis and recover some of the contract costs. Revenue created from transmission resell will be returned to customers through the ERM. However, Avista will maintain the long-term capacity rights on these important regional transmission assets to ensure delivery of energy to customers well into the future. (*Id.* at 28:17-22)

[120] Mullins, Exh. BGM-1T at 58:9-21.

[121] Mr. Mullins also recommends an NPE reduction of $206,000 to reflect the value of 100 MW of Company transmission rights to the California-Oregon Border (COB). An adjustment for COB transmission was not included in previous cases and is not included in the agreed power supply modeling methodology. One primary goal of the Workshops on power supply modeling was to simplify inputs. The parties agreed to a balanced modeling approach that included a single wholesale electric market and a single wholesale natural gas market, instead of representing all markets used by the Company. The parties agreed this simplification was fair and no further adder for COB transmission was included in the power supply methodology. (Kinney, Exh. SJK-17T at 30:9-18)

[122] Wilson, Exh. JDW-1TCR at 31:19-22.

92 To attest to the consequential value of this issue: In examining how large the impact of including CCA allowance costs in thermal plant dispatch is, the Company ran a scenario based on its original filing. The result was a $73.3 million (system) increase (42%) in NPE,[123] caused by lower surplus sales and additional market purchases to serve load in cases where the "phantom" carbon cost prevents dispatching lower-cost generation.[124] Clearly, much more needs to be understood about the ramifications of this issue.

IV. DERIVATION OF REVENUE REQUIREMENT

A. Introduction.

93 On rebuttal, the Company is requesting electric base rate relief in RY1 of $42.892 million effective December 21, 2024, or 7.3% (6.7% on a billed basis). In RY2, the incremental rate relief requested is $69.264 million effective December 21, 2025, or 10.9% (6.5% on a billed basis).

94 On rebuttal, the Company is requesting natural gas base rate relief in RY1 of $16.802 million effective December 21, 2024, or 13.2% (5.8% on a billed basis). In RY2, the incremental rate relief requested is $4.017 million effective December 21, 2025, or 2.8% (1.3% on a billed basis).

95 Staff, Public Counsel and AWEC's proposed revenue requirements for electric would result in earned equity returns (ROEs) in RY1 of 8.1%, 7.7% and 6.3%, respectively.[125] In RY2 their proposed revenue requirements would result in ROEs of 3.7%, 8.2% and 6.0%, respectively. These results reflect a reduction of anywhere between 130 to 310 basis points for RY1 and 120 to 570 basis points for RY2 below that currently authorized ROE of 9.4%, and again fall woefully

[123] *See* Company's response to Staff DR 227 in Kalich, Exh. CGK-8.
[124] Kalich, Exh. CGK-8 at 31:18-22.
[125] After rebuttal was filed, Staff adjusted its revenue requirement upward, but still leaving a substantial shortfall in ROE's.

short of providing the Company with a reasonable opportunity to earn its authorized rate of return.[126]

96 Staff, Public Counsel and AWEC's proposed revenue requirement for natural gas would result in earned equity returns (ROEs) in RY1 of 9.0%, 8.6% and 7.0%, respectively. Similarly, in RY2 their proposed revenue requirements would result in ROEs of 8.0%, 8.7% and 6.7%, respectively. These results reflect a reduction of between 40 to 240 basis points for RY1 and 70 to 270 basis points for RY2 below that currently authorized (9.4%) and would not provide the Company with a reasonable opportunity to earn its authorized rate of return.[127]/[128]

B. Contested Adjustments.

97 Please see Exh. KJS-6, page 2, for a detail listing of adjustments as updated by the Company and the list of contested adjustments.

- Legal/Wildfire Litigation Costs

98 AWEC Witness Mullins proposes to remove what he terms certain "non-recurring" legal and wildfire litigation costs.[129] Legal defense costs, including those for wildfire, are appropriate to include in customer rates. Annually, in the normal course of business, the Company becomes involved in various claims, controversies, disputes and other contingent matters, including wildfire

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126 Schultz, Exh. KJS-5T at 3:23 – 4:5.
127 *Ibid*.
128 The Company is requesting this Commission approve, subject to refund, proposed net plant after ADFIT, on a provisional basis, for Washington electric totaling $2,189,067,000 for RY1 and $2,281,707,000 for RY2. For Washington natural gas, the Company requests this Commission approve net plant after ADFIT balances of $558,255,000 for RY1 and $575,335,000 for RY2. (*Id*. at 4:6-10)
129 Mullins, Exh. BGM-1T at 33:14-20 and 34:1-15.

litigation. For all such matters, as appropriate, the Company will vigorously protect and defend its interests and pursue its rights, all of which benefit customers.[130]/[131]

- Non-Executive Labor

99 While Staff accepts the annualized portion of 2023 Union pro forma non-executive labor, it proposed to remove pro-formed Union labor increases for 2024 and 2025 due to what were ongoing contract negotiations at the time between the Company and the Union (IBEW Local 77).[132] However, Staff acknowledged they "would support including the 2024 and 2025 union wage increases in the revenue requirement on rebuttal should those increases become known."[133] Avista and the Union came to an agreement and the contract was ratified on July 31, 2024.[134] These increases have been ratified by the Union and Avista, and are known and measurable.[135]/[136] Staff also supported the use of the Board approved minimum for union and nonunion wage increases in 2026, if the Commission approved a multi-year rate plan.[137]

- Executive Labor

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130 The average level of expense over the last four years on a system basis for Avista is $2.407 million, as compared to the system level included in this case of $2.359 million. The level of legal expenses included in this case is also lower than the level actually experienced in 2023 (at $3.2 million). As such, the Company has been conservative and understated legal expenses in this case. (Schultz, Exh. KJS-5T at 39:1-5)

131 Avista will always have a level of patent costs as we develop new programs or systems for customers. Avista develops new ideas, programs, and systems that deserve protection, and the Company should be encouraged to seek such protection. (Schultz, Exh. KJS-5T at 36:14-20)

132 Hillstead, Exh. KMH-1T at 12:9-15.

133 *Id.* at 12:15-17.

134 The Company Local 77 bargaining unit came to agreement (a copy of the Letter of Agreement is provided as Exh. KJS-9, page 11) on a 5% merit increase for 2024 which will be retroactively paid, effective March 2024 and a 5% increase effective March of 2025, as reflected in Staff-DR-044 Supplemental 3. (Schultz, Exh. KJS-9 at 9-12)

135 The impact, therefore, to Staff's adjustment of the 2024 and 2025 approved union increases in RY1 would result in an incremental $1.846 million to Washington electric and $558,000 to Washington natural gas. (Schultz, Exh. KJS-5T at 43:1-15) The Company has also included within Adjustment 5.02, Pro Forma Non-Executive Labor, a 3% merit increase for 2026 for both Non-Union and Union employees. The Board approved a minimum 3% merit increase for both 2025 and 2026 in early 2024.

136 *See* Board of Director meeting minutes included with Schultz, Confidential Exh. KJS-10C at 12-15.

137 TR at 408:10 – 409:2.

100 Public Counsel Witness M. Garrett proposes to remove $60,000 of Washington electric expense and $19,000 of Washington natural gas expense for pro-formed executive compensation.[138] Executive pay is already allocated by the Company based on the responsibilities of each officer. A timesheet is completed bi-weekly for each employee of the Company, including officers. A portion of officer pay is allocated to a non-utility time code when performing work such as non-utility or shareholder activities.[139]

101 Avista's compensation philosophy for executives is market-based and benchmarked against similarly-sized peer investor-owned utilities. It works with its independent compensation consultant to benchmark executive roles and all salaries are approved by our independent Board of Directors Compensation Committee.[140] In the end, Mr. Garrett even acknowledges that "Avista's executive base pay seems reasonable when compared to other Investor Owned Utilities (IOUs)."[141]

- Employee Benefits

102 The Commission should reject Witness Mullins adjustment to Pro Form Pension Adjustment 3.07, as he only "cherry picked" the portion of the Company's update that was reduced between test period and that expected in 2025, choosing to exclude the additional increases to total

[138] M. Garrett, Exh. MEG-1T at 6:3-14.

[139] Witness M. Garrett also proposes that the Commission require a study of executive compensation in a separate proceeding. No study is needed. As part of Dockets UE-110876 & UG-110877, Avista completed and filed with this Commission a compliance filing on executive compensation. In that filing, Avista was found to employ acceptable methods for incorporating executive compensation in general rate cases. The overall methodology used today for determining types and levels of executive compensation, and pro forming adjustments (including in GRCs for rate recovery) is the same as the methodology found to be acceptable at that time. Since that compliance filing, Avista has filed many cases consistently following this methodology, with the levels of officer compensation included in each GRC reviewed, and ultimately approved in Washington base rates by this Commission. (Schultz, Exh. KJS-5T at 45:7-15)

[140] Staff-DR-041C (see Schultz, Confidential Exh. KJS-10C at 1-4).

[141] Schultz, Exh. KJS-5T at 7:8-9.

pension and medical costs, and arbitrarily removing the pension settlement amortization previously approved by the Commission.[142]

- Investor Relations Expense

103 Public Counsel Witness M. Garrett proposes to remove 50% of the costs associated with investor relations.[143] Such an adjustment to remove 50% of the costs associated with investor relations is entirely unreasonable.

104 Avista is an investor-owned utility which raises approximately half of the funds to operate our business on behalf of customers from the equity markets. Complying with SEC requirements is essential to maintaining legal and regulatory standards, which protects our Company from potential legal exposure and enhances our credibility in the market. Meeting with investors and the investment community allows the Company to communicate its strategic vision and the state of its financial health, potentially enabling it to issue equity on more favorable terms. This, in turn, provides the necessary capital to continue our mission in service to our customers. It is Avista's investor relations team that helps to facilitate such work.[144]

105 Consistent with Avista's rationale for having 90% of the costs associated with having a Board of Directors charged to utility customers, Avista can, however, support a 90% customer, 10% Company sharing of investor relations costs, as included on rebuttal.[145]

- Employee Incentives

106 The six-year average level of incentives recommended by Staff is a historical level of expense (2017-2022), and is thus understated, since labor will increase through RY1 and RY2 over

[142] *Id.* at 48:12-16.
[143] M. Garrett, Exh. MEG-1T at 34-36.
[144] Schultz, Exh. KJS-5T at 49:20 – 50:5.
[145] Avista today is comprised almost entirely of utility operations, with just a small set of passive investments under Avista Capital. (*Ibid.*)

the Two-Year Rate Plan. The Company used the expected 2024 incentive payout, which is reasonable and conservative.[146]

- Insurance Expense

107 Public Counsel Witness M. Garrett[147] proposes to allocate Directors and Officers liability insurance (D&O insurance) on a 50% customer, 50% shareholder basis. The Company continues to support a 90% customer, 10% shareholder allocation of D&O insurance. The Company has consistently applied the reduction of 10% for D&O insurance since ordered by the Commission in Dockets UE-090134 and UG-090135, Order 10. The rationale of the Commission still applies.[148]

- Board of Directors Fees

108 Both Public Counsel Witness M. Garrett[149] and AWEC Witness Mullins[150] propose to remove 50% of Director Fee compensation paid in cash and 100% of Director Fee compensation paid through shares of stock, resulting in a reduction in Washington expense of $819,000 for electric and $259,000 for natural gas. The Company believes it is appropriate to recover 90% of the Company's 12ME 06.2023 (test period) total Director Fee compensation levels expensed by the Company and supported in this case.

109 When surveyed to determine what percentage of time each Board of Director devoted to activities not directly related to the operations of Avista Utilities itself (non-utility), Avista's Board of Directors' average response ranged from 3% to 7%, with a total average for the Board of

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146 Schultz, Exh. KJS-5T at 53:6-8.

147 Garrett, Exh. MEG-1T at 30:6-8.

148 As the Commission stated in Order No. 10, at para. 137 in Dkts. UE-090134 and UG-090135: D&O insurance is a benefit that <u>is part of the compensation package offered to attract and retain qualified officers and directors. Accordingly, it makes sense to split the costs in the same manner we require other elements of their compensation to be shared</u>. Based on the formula currently used to allocate officer compensation between ratepayers and shareholders, this results in 90% of the costs being included for recovery in rates. (Emphasis added) (Schultz, Exh. KJS-5T at 54:16-21)

149 Garrett, Exh. MEG-1T at 27:11-13.

150 Mullins, Exh. BGM-1T at 32:13-17.

Director at 6%.[151]/[152] Plus it is important to remember that utility operations have become far more complex in recent years as confirmed by the issues in this very case – wildfire, energy supply markets, access to debt and equity markets, clean energy mandates, and the like. The proposal by the Company to exclude 10% of Board compensation (and D&O insurance expense as discussed above), therefore, is conservative.[153]

- Association Dues

110 Public Counsel Witness M. Garrett proposes to remove all costs associated with the Company's membership with the Edison Electric Institute (EEI) and American Gas Association (AGA).[154] To begin with, all costs associated with political activities and lobbying efforts paid to EEI and AGA are already excluded from customer rates. Other activities, however, do inure to the benefit of customers. EEI and AGA provide public policy leadership, critical industry data, market opportunities, strategic business intelligence, and one-of-a-kind conferences and forums, among other things. Ms. Schultz, at pp. 59-63 of Exh. KJS-5T, discusses the myriad benefits inuring to customers from membership in these organizations.

C. Miscellaneous Contested Adjustments.

1. Miscellaneous O&M/A&G Expense

111 The Commission should approve the electric and natural gas Miscellaneous O&M/A&G expense Pro Forma Adjustments 3.14 (RY1) of $9.0 million for electric and $223,000 for natural gas, and the incremental expense in PF 5.06 (RY2) of $1.6 million for electric and $346,000 for natural gas, as adjusted by the Company on rebuttal, reflecting 1) the updating of these expenses

151 This Board summary, as well as the individual Board of Director surveys are included as Exh. KJS-11.
152 Schultz, Exh. KJS-5T at 58:1-3.
153 Regarding Witnesses M. Garrett and Mullins removal of 100% Stock compensation, this Commission has never excluded, in full, director stock compensation, but has removed only a portion of total Director compensation to share between Utility customers and shareholders. Director compensation is targeted at the median of the peer group used to review executive compensation. (Schultz, Exh. KJS-5T at 58:6-8)
154 Garrett, Exh. MEG-1T at 15:8 – 24:17.

from the twelve-months-ended 06.2023 test period (12ME 06.2023) to the actual 12ME 12.2023 expense level, for this subset of O&M/A&G expenses, as supported by Staff witness Hillstead,[155] and 2) the escalating of 12ME 12.2023 balances by a 2.5% growth rate as supported by Public Counsel witness M. Garrett in RY1 and RY2.[156] (AWEC witness Mullins, for his part proposes a 2.3% growth rate beyond RY1 to RY2.[157])

2. Working Capital – Restating Adjustment 1.03 (RY1).

112 The Commission should approve the Company's as-filed electric and natural gas Investor Supplied Working Capital (ISWC or Working Capital) Restating Adjustment 1.03 and reject AWEC Witness Mullins[158] proposal to remove certain balances (Wells and Mizuho margin accounts FERC Accounts 134.122 and 134.123). The Company is following the methodology approved by the Commission in Avista's litigated proceeding, Dockets UE-190334, UG-190335, UE-190222, to remove the minimal interest-bearing portion of these accounts, resulting in restated 12ME 06.2023 ISWC rate base balances, as-filed by the Company, of $100.7 million for electric and $14.4 million for natural gas, which represent expected ISWC balances during the Two-Year Rate Plan. Furthermore, the Company has experienced a Washington lost return of over $6.3 million in 2023 alone, due to the increased ISWC balances experienced by the Company in recent years, mainly due to the increased power supply margin account balances, as opposed to that currently authorized in base rates, causing a substantial regulatory lag related to ISWC.[159]

3. Power Purchase Agreement & Interest - PF Adjustments 3.23 (RY1), PF 5.12 (RY2).

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[155] Schultz, Exh. KJS-5T at 16:12-16. Hillstead Exh. KMH-7, is a copy of Avista's response to PC-DR-297, which provides the change in O&M expense from twelve-months-ended June 30, 2023 (12ME 06.2023) to twelve-months-ended December 31, 2023 (12ME 12.2023), resulting in an increase in O&M expenses of $5.9 million for electric, and net reduction in O&M expense of $468,000 for natural gas.

[156] M. Garrett, Exh. MEG-1T at 12:1-4.

[157] Mullins, Exh. BGM-1T, at 19:12-20.

[158] Mullins, Exh. BGM-1T, at 29:11-22.

[159] Andrews, Exh. EMA-6T at 49.

113 The Commission should approve the Company's electric Pro Forma Power Purchase Agreement (PPA) Interest Adjustments 3.23 (RY1) and 5.12 (RY2), as proposed by the Company as-filed, to reflect the authorized rate of return approved by the Commission in this proceeding, resulting in increased interest income of $2.2 million in RY1 and an incremental increase of $176,000 in RY2.[160] The Commission should reject the removal of interest as proposed by NWEC Witness Gehrke,[161] and reject interest limited to the Company's cost of debt as proposed by Staff Witness Hillstead.[162]/[163]

4. Rent from Electric Property – PF Adjustments AWEC1 (RY1), AWEC2 (RY2)

114 The Commission should approve the Company's electric Pro Forma Adjustments AWEC1 (RY1) and AWEC2 (RY2) proposed on rebuttal, to reflect incremental joint use revenues (rent from electric property) from other utilities which place their utilities on our poles. The effect of these adjustments increases other electric revenue by $600,000 in RY1 and $200,000 in RY2. After review of Avista's 12ME 06.2023 test period other joint use revenue, the Company included this revision on rebuttal to reflect the appropriate rent from electric property over the Two-Year Rate Plan. This is in contrast to Witness Mullins proposed revenue,[164] which should be rejected, as his assumed levels are overstated based on one-time back-billing of joint users for unauthorized attachments.

[160] Senate Bill 5116 states (https://lawfilesext.leg.wa.gov/biennium/2019-20/Pdf/ Bills/Senate%20Bills/5116-S2.E.pdf), in reference to the transition to clean energy, that the "legislature declares that utilities in the state have an important role to play in this transition, and must be fully empowered, through regulatory tools and incentives, to achieve the goals of this policy." The purposeful inclusion of "a rate of return of no less than the authorized cost of debt and no greater than the authorized rate of return of the electrical company…" (see Sec. 5, p. 2) is, in the Company's view, just such an incentive. (*Id.* at 6, n.26)
[161] Northwest Energy Coalition (NWEC), Gehrke, Exh. WG-1T, at 2:5-17.
[162] Hillstead, Exh. KMH-1T, at 18:10-17.
[163] Andrews, Exh. EMA-6T at 6:25 – 7:2.
[164] Mullins, Exh. BGM-1T, at 24:9-26:1.

D. Customer Tax Credits – Flow Through vs Deferral Balances.

1. Deferral of IDD#5 & Meters Tax Deductions vs Flow Through Tax Benefits.

115 The Commission should reject AWEC Witness Mullins recommendation that Avista be required to fully transition to "Flow-Through" accounting of its 2025 estimated tax deductions associated with IDD#5 and meters expenditures, moving this deduction to base rates, as an offset to electric and natural gas current tax expense in RY1 of approximately $4.4 million and $0.9 million, respectively.[165] All tax credits are deferred for the benefit of customers, as currently authorized per Order 01 in Dockets UE-200895 and UG-200896 and returned to customers thorough Separate Tariff Schedule 78 (electric) and 178 (natural gas). This tracking mechanism allows the Company to account monthly for any amortizations and deferrals of estimated tax deductions in the current year, as well as true-ups for actual tax deductions, for any changes from estimates and as approved by the Internal Revenue Service (IRS) over time. This, in-turn, protects both customers and the Company from any inaccuracies of the future estimated tax deduction estimates for these items from year to year, and it tracks actual dollar-for-dollar tax benefits owed as a benefit of customers.[166] In fact, customers were better off in 2022 and 2023 by $3.4 million due to such "true-ups" because of the deferral mechanism.[167]

2. Accounting for the Return on the Change in Rate Base.

116 The Commission should reject Witness Mullins calculated Tax Credit Deferred Balances[168] that he argues Avista owes customers as of December 2024 totaling $5.7 million electric and $5.4 million natural gas. Witness Mullins claims Avista did not have the authority to account for the

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165 Mullins, Exh. BGM-1T, at 36:15 – 37:5.
166 Andrews, Exh. EMA-6T at 6:26 – 7:2.
167 Andrews, Exh. EMA-6T at 59, Table No. 5 (footnotes (2) and (3). If not for the deferral mechanism, actual deferred tax credit true-ups of $1.4 million in 2022 and $1.9 million in 2023 (or $3.4 million total) would have "flowed through" as proposed by Witness Mullins, benefiting shareholders, rather than deferred for later return to customers.
168 Mullins, Exh. BGM-1T, at 38:12 – 39:12; Andrews, Exh. EMA-6T at 7:4-15.

return on the change in rate base over time, as the Company refunded the deferred customer tax credits to customers.[169] He then proposes the Commission amortize and return his calculated balances over 1-year in RY2 for electric and over two-years in RY1 and RY2 for natural gas through separate Tariff Schedules 78 and 178.

117 Witness Mullins, however, ignores, that over the 4-year period from October 2021 – December 2024, the Company will have returned $68.1 million of Washington system Customer Tax Credits – all while this balance has reduced rate base by $68.1 million, and, reduced <u>base rates</u> collected from customers by approximately $9.7 million, over this same 4-year period. In order to remain whole, over this same time, Avista recorded a monthly offset against the deferred customer tax credits and for the return on the change in rate base. Avista's accounting for these tax credits has kept customers whole – returning no more, no less owed them.[170]

E. <u>Rate Year 2 (2026) Removal of Colstrip/Colstrip Transmission Costs</u>.

1. <u>Removal of Net Power Supply Colstrip Costs in RY2 (2026)</u>.

118 The Commission should approve the Company's adjustment included in RY2 Pro Forma Power Supply Adjustment 5.00P to remove Colstrip Unit 3 and 4 from base rates as mandated by law on or before January 1, 2026, resulting in an increase in net power supply expense and an increase in overall electric revenue requirement of $54.2 million.[171] Offsetting this increase in NPE and base rates in RY2, however, will be the reduction in the separate Colstrip Tariff Schedule 99,

[169] *Ibid.*

[170] Andrews, Exh. EMA-6T at 8:1-15. If this Commission were to approved Witness Mullins proposed amortization treatment, this would require an immediate write-off on Avista's books of record in December 2024 of $9.7 million for tax credits already returned to customers.

[171] Company witness Mr. Kalich at Exh. CGK-7T, at 5:10 - 7:23, discusses Avista's recommendation for approval of the updated net power supply expense sponsored on rebuttal, which would remain in place over the Two-Year Rate Plan, with the exception in RY2 for the impact of removing Colstrip as required by law. This allows the Commission to approve base rates in RY1 and RY2, <u>without a RY2 60-day update</u>, resulting in final base rate changes or customer impacts being known <u>at this time</u>. Furthermore, if the Commission were to approve the ERM updates as proposed by the Company, with a revised deadband and 90/10 sharing, an appropriate amount of any actual changes up or down would be deferred for recovery or surcharge at a future time.

reflecting the reduction in costs of removing Colstrip O&M and other expenses, depreciation expense, and return on rate base, reflecting only the recovery of D&R Regulatory Asset/Liability balances and amortization expense on an on-going basis. This reduction to Colstrip Tariff 99 will reduce "billed" rates to customers by approximately $24.4 million (Washington expense).[172]

2. On-Going Colstrip Transmission Assets and Other Costs.

119 The Commission should reject Witness Mullins recommendations to remove net Colstrip Transmission assets as of December 31, 2025 of $6.6 million and Colstrip wheeling costs of $4.0 million, reducing the revenue requirement as proposed by Witness Mullins by $1.9 million (AWEC-5.14) and $4.2 million (5.00P), respectively.[173] Company witness Mr. Kinney describes the usefulness of the Colstrip transmission assets and point-to-point transmission rights beyond December 31, 2025, after the removal of the Colstrip Unit 3 and 4 generation assets.[174]/[175]

F. Uncontested Items.

1. Uncontested Adjustments.

120 Exh. KJS-6 at page 1, provides the listing of uncontested adjustments, totaling 32 electric and 24 natural gas uncontested adjustments in RY1, and 6 electric and 2 natural gas uncontested adjustments in RY2.

2. Deferral of Coyote Springs 2 Major Maintenance and 2-Year Amortization.

121 The Commission should approve the Company's request to defer the actual Washington share of its Coyote Springs 2 (CS2) major maintenance (estimated at $12.0 million), with a carrying charge of actual cost of debt on both the deferred balance and during the proposed 4-year

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172 Andrews, Exh. EMA-6T at 7:17-34.
173 Mullins, Exh. BGM-1T, at 57:12-19 and 58:1-21.
174 Kinney, Exh. SJK-17T, at 25:9 – 30:18.
175 Furthermore, the Commission ordered the Colstrip transmission assets, including transmission decommissioning and remediation (D&R) costs, be depreciated consistent with the depreciation rates for non-Colstrip transmission assets as approved in Depreciation Docket UE-180167, so long as the Colstrip transmission assets are used and useful consistent with RCW 19.405.030(2). See Order 09, Docket UE-190334, et.al., p. 18, par. 47-48.

amortization period. This maintenance is required after 32,000 fired-hours (approximately every 4 years), and therefore which will occur in 2025 or 2026 depending on actual run hours. The Company has proposed a 4-year amortization to begin July 2026 – June 2030. No party has contested the Company's proposal or its pro forma CS2 Amortization adjustment.[176]

3. New Regulatory Amortizations.

122 The Commission should approve the Company's various New Regulatory Amortizations, amortized over a two-year period, as discussed by Ms. Schultz at Exh. KJS-1T at pages 75 – 83, included in Pro Forma Adjustment 3.18, and uncontested by the parties.

4. Outage Management System & Advanced Distribution Management System – Request for a 15-Year Life.

123 The Commission should approve the Company's request for a 15-year life for certain software assets transferring to plant in 2025 within the Outage Management System & Advanced Distribution Management System project, due to a longer expected life of those software assets. Of the 2025 transfers-to-plant expected for the project, approximately $20.5 million will be associated with this 15-year asset. Without approval in this case to use a 15-year depreciable life for certain software, the Company would be required to depreciate the project over 5 years, which would substantially increase the cost to customers, while not reflecting the fact that Avista will in all likelihood use this new system for well beyond its 15-year requested life.[177] This request was uncontested by the parties.

5. Electric and Natural Gas Decoupling Mechanism.

[176] Andrews, Exh. EMA-6T at 74:8 – 76:16.
[177] Benjamin, Exh. TCB-1T at 38:6 – 39:15.

124 The Commission should approve the Company's request to extend the current electric and natural gas Decoupling Mechanisms to December 31, 2026. This request was uncontested by the parties.

6. Weather Normalization.

125 The Commission should approve the Company's uncontested request to (1) adjust the definition of "normal" weather from a 30-year rolling average to a 20-year rolling average; (2) to adjust its non-degree day seasonal regression factors from seasonal factors to monthly factors; and (3) allow for non-linear behavior in the relationship between HDD and non-weather, non-seasonal use-per-customer (UPC) trends.

V. CAPITAL RECOVERY/BALANCING ACCOUNTS/COLSTRIP REMOVAL

A. Provisional Capital Investment & Recovery.

126 The Company has provided full support of provisional capital investments for 2024 through 2026[178] in the Company's direct case, allowing this Commission to approve an overall net plant after ADFIT level in RY1 and RY2,[179] subject to review and refund through the after-the-fact Provisional Capital Report process, with the exception of extending parties review of these reports from four months to six months, as proposed by Staff.[180] The Company does not, however, believe separate provisional capital tariffs outside of base rates are necessary to track these

178 Avista's 2023 Capital Investments were deemed prudent per Commission confirmation on July 31, 2024, with a finding that Avista's 2023 Provisional Capital Report complies with Order 10/04, and these investments are no longer subject to refund. (Andrews, Exh. EMA-6T at 4, n.9)

179 Net plant after ADFIT (including gross plant investment, offset by Accumulated Depreciation (AD) and Accumulated Deferred Federal Income Taxes (ADFIT)) for RY1 and RY2 on rebuttal are provided by Ms. Schultz per Exh. KJS-7 (electric) and Exh. KJS-8 (natural gas). Specifically, the Company is requesting this Commission approve electric net plant after ADFIT balances of $2,189,067,000 for RY1 and $2,281,707,000 for RY2 (see Schultz, Exh. KJS-7, p. 1, column h, row 46 (RY1) and Exh. KJS-7, p. 2, column g, row 46 (RY2)). For natural gas, the Company requests this Commission approve natural gas net plant after ADFIT balances of $558,255,000 for RY1 and $575,225,000 for RY2 (see Schultz, Exh. KJS-8, p. 1, column h, row 42 (RY1) and Exh. KJS-8, p. 2, column g, row 42 (RY2)).

180 Erdahl, Exh. BAE-1T, at 8:4 – 11:11.

balances until final prudency determination, as proposed by Staff,[181] as this would add unnecessary complexity and administrative burden to all parties,[182] and the process is working as intended, as discussed below.

127 This Commission should deny AWEC Witness Mullins RY1 and RY2 Provisional Capital Adjustments[183], adjusting net plant after ADFIT in each rate year from the average-monthly-average (AMA) basis, as proposed by the Company, to its end-of-period (EOP) basis, prior to new rates going into effect, and an attestation of this net rate base at end of year, <u>on a project-by-project basis</u>. AWEC's proposal is unreasonable and would not allow Avista the opportunity to earn its authorized rate of return and would result in taking steps backward from the progress made in the last few years under new MYRP legislation (SB 5295).[184] No other party contested the Company's Pro Forma or Provisional Capital Adjustments (or the process for reviewing them), except for the impact of these adjustments on parties' positions on cost of capital.

- <u>"Portfolio" Versus "Project-by-Project" Review of Provisional Capital</u>.

128 Avista strongly opposes AWEC Witness Mullins' proposal to depart from the "portfolio" approach to subsequently reviewing "provisional capital" during the annual review under the Rate Plan.[185] This would be a significant departure from what has worked successfully for Avista's last two provisional capital annual reviews for both 2022 and 2023 (the first two years' of experience under Avista's first approved MYRP). It is also antithetical to the very purpose and intent of the

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181 *Id.* at 10:12-21
182 Andrews, Exh. EMA-6T at 8:29 – 9:13.
183 Mullins, Exh. BGM-1T, at 9:18 – 14:10.
184 As discussed by Ms. Andrews at Exh. EMA-6T at 19:12-15, the Company has included significant RY1 and RY2 off-setting factors, reducing the Company's revenue requirement, related to increased provisional capital investment. (See also Schultz Exh. KJS-5T at 17:1-18:15 for updated off-setting factors on rebuttal.) Witness Mullins did not recognize in his adjustments to reduce rate base to EOP investment prior to rates going into effect there would be significant off-setting factors in RY1 and RY2 that would also have to be removed.
185 Mullins, Exh. BGM-1T at 9:18 – 14:10.

MYRP rate plan legislation, which was to provide a means for flexibility in incorporating new capital into rates without the need for annual base rate filings.

129 The framers of the MYRP legislation understood the need for flexibility when moving capital into rates during a Rate Plan of 2-to-4 years in duration. During that time, capital needs evolve, project scope can change, and new projects may emerge that take priority. Without that flexibility to incorporate capital into rates, the MYRP legislation would have failed of its intended purpose.

130 That is not to say, however, that the Company is given a "blank check" to build into rates projects that are not given sufficient review for prudency. The legislation anticipates that, by providing for annual prudency reviews during the Rate Plan and a <u>refund</u> of imprudent expenditures or where the "portfolio" of investments does not rise to the level of what is built into rates. (This is <u>not</u> a situation where Avista will be recovering through rates capital that is not used and useful and prudent during the Rate Plan – i.e., the overall level of prudent investment is at or above what is built into rates.)

131 Chairman Danner was quite right in asking about Staff's ability to "scrutinize" the annual capital reports, "to make sure that we're treating these provisional plant numbers correctly."[186] While Staff Witness Erdahl did acknowledge that she would like "more time and resources" to review the "provisional" capital filings, she also understood the need for "flexibility" in incorporating new capital: "[W]e support a provisional portfolio basis review; so there's some flexibility for the Company to switch gears if they need to depending on their business needs."[187]

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[186] TR at 396:23-25.
[187] TR at 398:19-23.

132 Sometimes a simple everyday illustration serves to remind us of why "flexibility" matters: As homeowners, we prudently attempt to budget for needed home repairs and improvements over the next two or three year period. This is meant to preserve and extend the value of the home, and we set aside funds for that purpose. While we may plan to repaint the exterior, a suddenly failing HVAC system may demand our immediate attention and dollars are shifted. Indeed, to not make this mid-course correction would be imprudent if it detracts from the useability or life of the asset. Much as a homeowner, we are stewards of our customers' dollars that must be spent as wisely as possible – when and where needed.

133 Staff requested an extension of the review period for provisional capital from four to six months – and the Company does not object.[188] Moreover, it is important to understand the scope and extent of this review.

134 So, for context, how big a problem are we dealing with, as new capital is incorporated, taking into account the need for flexibility as things change over a two-to-four year planning horizon?

135 Commissioner Rendahl asked Staff Witness Erdahl about the number of new Business Cases in the Company's 2023 provisional plant filing that were not already included in its 2023 GRC.[189] She replied, subject to check, that 21 were not existing business cases, but could not otherwise identify the associated dollar amounts. Staff subsequently completed its "subject to check" confirmation, and on October 8, 2024, submitted downward revisions to the tabulations for both rate year 2022 and 2023, which is excerpted below:

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188 Erdahl, Exh. BAE-1T at 8:4 – 11:1.
189 TR at 399:23 – 400:9.

Rate Year	Business Case Count	Dollar Value of New Business Cases	Reference
2022	117 total business cases 3 new business cases	Total value of new business cases: $1.5 million, system One business case was less than $200,000, system	Exh. TCB-4, Attach. A (From Docket UE-240004 and UG-240007)
2023	123 total business cases 8 new business cases	Total value of new business cases: $7.6 million, system Three of the new business cases were less than $275,000 each (totaling $729,810).	2023 WA Annual Provisional Capital Report (From Docket UE-220053 and UG-220054, filed 3/29/2024)

136 In its Bench Request 002, the parties were asked to clarify any "discrepancies" around the tabulation of new Business Cases under review.

137 As provided in Avista's response to Bench Request 002, in 2022 and 2023 the total "New" Business Cases equate to **3 (out of 117 cases) in 2022** totaling $1.5 million, and **8 (out of 123 cases) in 2023** totaling $7.6 million, on a system basis. For 2022, Washington's share of the 3 "New" Business Cases ($1.5 million) totals approximately $556,000 for Washington electric and $496,000 for Washington natural gas. For 2023, Washington's share of the 8 "New" Business Cases ($7.6 million) totals approximately $4,468,000 for Washington electric and $36,000 for Washington natural gas.[190] As also demonstrated in this Response to Bench Request #2, if one were to simply take the "Business Cases included in GRC" for 2022 and 2023 as noted in the tables above, and compare to the amount included in rates, in aggregate ($895.3 million system) to actuals ($899.5 million system), one would see a difference of only 0.47%.

[190] In 2023, Rate Year 1 of Docket UE-220053, et. al., 2023 net plant investment impacts Company results on an AMA basis. Therefore, the AMA amounts in 2023 of the 8 projects total approximately $1,409,000 for Washington electric and $8,000 for Washington natural gas. The combined total of 2022 and 2023 New Business Cases (11) in RY1 (2023) for Washington has an overall regulatory lag on rate base of $2.0 million electric and $504,000 natural gas, resulting in a revenue requirement regulatory lag of approximately $184,000 electric and $47,000 natural gas. This equates to 0.84% of "NEW" TTP versus that approved by the Commission in RY1 (2023), i.e. less than 1%. This same capital results in a Washington total rate base regulatory lag in 2024 (Rate Year 2 of Docket UE-220053 et. al.) of $5.4 million electric and $630,000 natural gas, resulting in a revenue requirement regulatory lag of approximately $504,000 electric and $59,000 natural gas on this investment.

138 Expressed differently, and as shown in the 2023 Provisional Capital Report, page 5, Table No. 1 (electric) and Table No. 2 (natural gas), the total "As-Filed Net Plant After ADFIT" approved by the Commission in Dockets UE-220053, et. al., for Rate Year 1 (2023 AMA[191]), totaled $1,984,056,000 for Washington electric and $510,148,000 for Washington natural gas (Washington total of $2,494,204,000). In comparison, Avista's "Actual Net Plant After ADFIT" for Rate Year 1 (2023 AMA) totaled $2,004,497,000 for Washington electric and $510,148,000 for Washington natural gas (Washington total of $2,514,645,000). **This reflects an incremental actual net plant investment of $20,441,000 for electric (or 1.0%) and $1,634,000 for natural gas (or 0.3%) above authorized net plant approved by the Commission for Washington investment.**[192] Combined for total Washington ($22,075,000), Avista's actual incremental net plant investment above that approved by the Commission in the prior 2022 general rate case, equates to 0.9% above authorized levels for Rate Year 1 (2023). This minimal incremental increase of overall 0.9% Washington net plant investment above that approved by the Commission represents regulatory lag experienced by Avista between general rate cases.

139 Clearly, only a very small number of new business cases are in need of review during the six-month provisional capital review process, and the overall dollars at issue are relatively modest.

140 In its Bench Request No. 002, in addition to seeking clarification around the number of new Business Cases included in "provisional" capital, the Commission requested further comment on the existing and future "provisional" plant review process. In short, that process is working as intended, for reasons explained above and as further discussed below.

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[191] 2023 Average-of-Monthly-Average balances include 2022 and 2023 net plant investment on an AMA basis for Rate Year 1.

[192] See 2023 Provisional Capital Report (See Avista Bench Request 002 Attachment B), page 5 Table No. 1 (electric) incremental of $20.441 million / $1,984.056 billion authorized = 1.0%. See page 5 Table No. 2 (natural gas) incremental $1.634 million / $510.148 million authorized = 0.3%.

141 The "process" itself was an agreed-upon process approved by the Commission in Dkts. UE-220053 in Order 10/04 at ¶79. The March 29, 2024 Compliance Filing (for the 2023 annual Provisional Capital Report) is attached to Avista's response to Bench Request No. 002, and describes, in detail, the prescribed procedure, along with full supporting documentation. (Ultimately, no party challenged this filing and it was acknowledged by the Commission.) That agreed upon process fully describes the manner in which changes Business Cases are addressed (see Attachment C to the Report) including a full explanation of all variances.

142 Future "provisional" plant review will follow on the same course (albeit with an extended review). The Company has included provisional capital investment for the period 2024 through 2026. Parties to this proceeding will have an opportunity to review final actual capital investment through Avista's 2024, 2025 and 2026 Provisional Capital Reports, filed annually on or before March 31st, comparing actual investments to the capital investment and net plant approved by this Commission.

143 Through the annual Provisional Capital review of these investments by the parties, if it is determined the Company underspends the net plant investment as approved by the Commission, or any capital investment is deemed imprudent, the Company will defer the appropriate amount collected from customers for later return to customers. If the Company's net plant investment amount is higher than that approved by the Commission, and yet ultimately deemed a prudent investment, that investment will result in regulatory lag until included in the next general rate case.[193]

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[193] If net plan investment above that approved by the Commission is deemed prudent and material on a revenue requirement basis, the Company may seek to have the opportunity for deferred accounting treatment, if deemed necessary, allowing for the opportunity to reduce some of this regulatory lag between general rate cases.

144 In short, the "provisional" capital review process is working as intended and it is an integral part of any MYRP and should be seen as such. At the end of the day, the approved rates will recover no more than the actual level of net plant approved by the Commission in the Two-Year Rate Plan. (It is "capped" at that level.) It will receive the necessary scrutiny envisioned under the MYRP legislation.[194] Any levels of plant that exceed that level will be subject to review in the next GRC.[195]

B. Balancing Account Adjustments.

1. Wildfire Expense and Balancing Account Baseline.

145 The Commission should approve the Company's electric Wildfire Expense Adjustment 3.24, adjusting the Company's wildfire expense and Wildfire Expense Balancing Account baseline to $8.3 million over the Two-Year Rate Plan, including a carrying charge at the Company's cost of debt on the deferred balances (current and on-going), and during amortization of these deferred balances, as-filed by the Company, and supported by Staff,[196] and uncontested by the remaining parties. In addition, the Company requests the Commission allow the Wildfire Expense Balancing Account "tracker" to continue beyond this GRC, at least through 2029 (over the 10-Year Wildfire Resiliency Plan) as previously approved by this Commission in Dockets UE-200900, et. al., and does not believe the Commission should remove the Balancing Account tracker in the Company's next GRC as proposed by Staff,[197] as this tracker acts as protection for customers and the Company, if costs expected over the life of the Wildfire Plan vary from that included in base rates.[198]

2. Insurance Expense and Balancing Account Baseline.

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[194] Under no circumstances should there be a perverse incentive to only do what is specifically laid out in the Business Case (followed "to the letter") where mid-course corrections over a two-year rate plan are warranted.
[195] This is not the case where the "provisional" capital is less than what was included in rates, necessitating a refund.
[196] Erdahl, Exh. BAE-1T, at 26:12-16.
[197] *Id.* at 27:14 – 29:3.
[198] Andrews, Exh. EMA-6T at 28-32.

146 The Commission should approve the Company's electric and natural gas Insurance Expense Adjustments 3.12, updating the Company's insurance expense and its proposed Insurance Expense Balancing Account baselines, over the Two-Year Rate Plan, to $12.8 million for electric, and $2.3 million for natural gas, as filed by the Company. The Pro Forma Insurance Expense Adjustment was uncontested by Staff,[199] as well as by Public Counsel, with the exception of adjusting the current authorized D&O Insurance expense sharing of 90% Customer / 10% Company, to a 50%/50% sharing as proposed by Public Counsel and discussed above.[200] The inclusion of a carrying charge at the Company's cost of debt on the deferred balances (current and on-going), and during amortization of these deferred balances, was supported by Staff[201], and uncontested by the parties.

147 AWEC witness Mullins, however, opposes the continuation of the Insurance Expense Balancing Account,[202] a position the Commission should reject, as it has been made evident, as recognized by Order 10/04 in Dockets UE-220053, et. al., that the volatility experienced by Avista, and the utility industry, is extraordinary and outside the Company's control. Commission-approved "tracking mechanisms" were created for this very reason, to protect the Company and customers from "extraordinary" circumstances and volatility in certain expenses.[203]

VI. DISTRIBUTION PLANNING / CAPITAL INVESTMENTS

A. Capital Investment & Recovery.

199 Erdahl, Exh. BAE-1T, at 32:3-8.
200 M. Garrett, Exh. MEG-1T, at 34:4-12.
201 *Id.* at 32:18 – 33:3.
202 Mullins, Exh. BGM-1T, at 64:17-65:14.
203 Andrews, Exh. EMA-6T at 33-38.

148 The Company disagrees with Staff witness Sofya Shafran Atitsogbe Golo's (Atitsogbe) portrayal of the prudency of the Company's electric distribution system investments. Staff Witness Atitsogbe argues that:

> Avista has failed to present sufficient evidence to establish the prudency of its electric distribution system investments because the Company has not complied with many of the planning requirements relevant to its distribution system and has not offered sufficient evidence supporting the specific distribution investments included in this rate case.[204]

149 The Company has demonstrated in its original testimony and exhibits, and again in its rebuttal testimony and exhibits, that it has a robust planning standard that (1) evaluates the need for projects it undertakes, (2) reviews alternatives, including in its Business Cases, and (3) provides adequate documentation.[205]

150 The distribution planning process includes consideration of the need for a Distribution Resource Plan, integration with the existing IRP processes and includes interested parties' involvement in the selection of the most prudent action plans. Improvements to forecast methodologies for both customer demand and growth of DERs are also part of this approach.[206]

151 Avista has a ten-year plan for distribution system investments and an analysis of alternatives for major transmission and distribution investments. Avista also bi-annually produces a system assessment to achieve two primary outcomes: (1) documentation of technical analysis results demonstrating system performance and (2) development of conceptual solutions to mitigate operational issues to maintain expected performance. The most recent system assessment, the

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204 Atitsogbe, Exh. SSAG-1T at 2:15-19.

205 The Board approves the level of capital Avista invests on behalf of its customers and approval of the capital budget and is otherwise kept apprised, through the Finance Committee, of ongoing investment throughout the year. (DiLuciano, Exh. JDD-3T at 4:17-20)

206 *Id.* at 20-24.

2023-2024 System Assessment Version 0, dated November 17, 2023 was provided as Exhibit JDD-4.[207]

152 Avista also provides for the engagement of interested parties in the planning process. The Distribution Planning Advisory Group (DPAG) was formed in 2023 to meet the requirement of Condition 13 of Avista's 2021 CEIP. All existing advisory groups[208] were invited to participate in the DPAG.[209] Avista's planning documents also include an assessment of DERs.

153 Avista has also complied with RCW 19.280.100 regarding DER planning. Both prior to and following Washington House Bill 1126 becoming effective on July 28, 2019, Avista has been making progress on meeting the policy outlined in RCW 19.280.100. As summarized by Witness DiLuciano, Exh. JDD-3T at 19:17-29:

> (1) Avista has provided sufficient DER assessments as discussed. The DER Potential Assessment, deployment of smart devices with grid monitoring capability, advancements in utilizing Advanced Metering Infrastructure data, and continued publication of a ten-year plan are examples of Avista engaging in the process to prepare for the distributed energy future. Additionally, Chapter 5 of Avista's 2023 Electric IRP[210] contains information related to DERs and data specific to Avista's service territory.
>
> (2) Avista has completed a DER potential study – see Exh. JDD-10.
>
> (3) Avista has provided evidence that it is engaging in the planning process contemplated by the Legislature in RCW 19.280.100.

154 Staff also proposes an extensive list of documentation for the Company to provide for five preceding years of distribution system investments.[211] The Company already provides thousands of pages of documentation to support capital investments when filing a general rate case and then

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[207] *Id.* at 8:1-8.
[208] Avista Energy Efficiency Advisory Group, Energy Assistance Advisory Group, and Equity Advisory Group.
[209] *Id.* at 9:3-18.
[210] Kinney, SJK-2 at 106-127.
[211] These include providing financial data regarding Avista's distribution system investments by categories, "data on and a discussion of Avista's distribution system operation and maintenance expenses," and a "five-year long-range forecast of distribution system capital investments and operational and maintenance expenses." (Atitsogbe, SSAG-1T at 27:21 – 29:14)

provides hundreds of pages of additional documentation as part of the subsequent provisional review proceeding, showing the investments as used and useful. A Business Case justification narrative (e.g., 123 Business Cases in this case for 2023) is also filed as part of a general rate case for every capital investment the Company includes on a pro forma or provisional basis. To request the Company to provide the additional level of detail that Staff recommends for <u>all</u> distribution capital investment would be an additional and unnecessary burden on the Company, given the information already available. There has been no showing that more documentation is needed or the impacts of this burden on Staff to review.

155 Staff would also require the 2025 IRP to include additional analysis that is not even possible to include, given the current schedule of the 2025 IRP and this proceeding. This analysis would include extensive information on "DERs in Avista's distribution system" and "grid development scenarios."[212] The draft of the 2025 IRP was filed with the Commission on September 2, 2024, the rate effective date in this case is December 21, 2024, and the final draft of the IRP is due on January 2, 2025. As such, if the Commission approves of Staff's proposal, it is simply not possible to include the requested analysis in the 2025 IRP. And requiring an update to the 2025 IRP on June 1, 2025, would require a refiling of the 2025 IRP, after work has already been started on the 2027 IRP.[213]

156 Nor would Avista otherwise agree with this condition if it was to be included in its two-year IRP update or 2027 IRP. First, the IRP is not the appropriate place to provide <u>distribution</u> level data and to address all system delivery planning challenges. Mr. DiLuciano concludes: "In

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212 *Ibid.*

213 Although an IRP is due every four years in Washington, the Company must prepare a two-year update for Washington and full IRP for the State of Idaho every two years.

short, the IRP should not morph into a combined delivery and power plan, that detracts from its essential focus on resource planning."[214]

B. Consideration of Non-Pipe Alternatives (NPAs)

157 Sierra Club claims that Avista has not performed any NPA analyses as required by its 2022 rate case settlement.[215] The rate case settlement, however, did not require that any NPA analyses be performed; rather, the settlement required that the consideration of NPAs be incorporated into gas planning.[216]/[217] Avista's gas distribution planning process <u>does</u> otherwise include an evaluation of NPAs when considering reinforcement alternatives not related to safety, compliance, or road moves that exceed $500,000. Nevertheless, Avista does support the following:[218]

> Upon the rate-effective date, NPA analysis will be performed for supply-side resources and for distribution system reinforcements and expansion projects not related to safety, compliance, or road moves, that exceed a threshold of $500,000 for individual projects or groups of geographically related projects.
>
> If a NPA is not selected, Avista will include the NPA analysis as part of the justification when it seeks recovery of the resource addition or distribution system reinforcement or expansion in a rate case. Mr. DiLucino provides further specifics in support of this effort in Exh. JDD-3T at 29:1-30:24.[219]

C. Consideration of Equity in Business Processes.

Staff Witness Erdahl[220] and NWEC Witness Thompson[221] both provided generally

[214] DiLuciano, Exh. JDD-3T at 23:20-21.
[215] Dennison, Exh. JAD-1T at 24:14-19.
[216] *Id*. at 26:1-21.
[217] Sierra Club is correct that no NPA analyses have been performed in Washington since approval of the settlement from the 2022 rate case, however, this is because the Company <u>has not had any projects that have met its criteria or threshold for an NPA to be considered</u>. If and when such a project arises, the Company will consider NPAs. (Bonfield, Exh. SJB-5T at 45-56.)
[218] *Id*.
[219] Finally, Avista disagrees with the proposed recommendation to perform an NPA analysis on five projects in the next IRP. (Dennison, Exh. JAD-1T at 30:10-19) First, the Company may not have five projects to perform such an analysis on. Second, the 2025 IRP is due on April 1, 2025, with a draft to be published in Q1 2025, thereby leaving little to no time to complete such an analysis, even if directed to do so by the Commission. Third, performing an NPA analysis on projects that do not meet the $500,000 threshold is not the best use of Avista's time and resources, which are ultimately paid for by customers. (Bonfield, Exh. SJB-5T at 30:21-27)
[220] Erdahl, Exh. BAE-1T at 16-20.
[221] Thompson, Exh. CT-1T at 6

supportive testimony on the interpretation of equity (energy equity) in this case.[222]/[223] The Company also appreciates the recognition offered by NWEC Witness Thompson regarding ways in which it has advanced energy equity. NWEC has been a valuable member of the Company's many advisory groups, where those groups have collaborated to advance energy equity. Regarding the additional perspectives to advance energy equity offered by Witness Thompson, Company witness Mr. Bonfield provides a response to each of the individual elements offered at Exh. SJB-1T at 19.[224]

VII. MISCELLANEOUS CUSTOMER SPECIFIC PROPOSALS

158 The testimony of Company Witness Bonfield provides Avista's response to the testimony of Staff, The Energy Project (TEP), NWEC, and Sierra Club, regarding the affordability of Avista's bills, disconnection policies, a Low Income Needs Assessment (LINA) & Energy Burden Assessment (EBA), customer demographic data, language access, Performance Measures pursuant to RCW 80.28.425(7), Performance Based Ratemaking (PBR) metrics, recurring reporting obligations, natural gas energy efficiency, a decarbonization plan, and electrification.[225] He conveniently summarized his primary points on rebuttal, which are reproduced below:

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222 Staff Witness Erdahl explained how (1) Avista is incorporating equity into its business planning processes; (2) the requirement from Avista's 2022 GRC for Avista to develop methods and standards for distributional equity analysis (DEA); (3) Staff's perspective of how well Avista addressed equity in this case; (4) Staff's review of the formalization of equity-related duties for the Senior Vice President, Chief Strategy, and Clean Energy Officer, and Equitable Business Planning charter; (5) Avista's launch of its equitable business planning process; and (6) Staff's equity concerns with Avista's approach to incorporating the cost of carbon allowance compliance instruments in power supply forecast and dispatch decisions. (Exh. BAE-1T at 16-20)

223 NWEC Witness Thompson highlighted four ways in which she believes Avista is:

> … making meaningful effort and progress in advancing energy equity, including: (1) progress on its 2022 GRC settlement commitments; (2) progress on its 2021 CEIP commitments; (3) facilitation of its energy assistance advisory group; and (4) participation in the Commission docket on equity (A-230217). (Exh. CT-1T)

Moreover, the Company agrees with Staff's plan to plan to offer a more detailed analysis of its equitable business planning process in Avista's next rate case, which is after the Company is able to gain more experience with its equity efforts. (Erdahl, Exh. BAE-1T at 20:5-10)

224 Bonfield, Exh. SJB-1T at 19.

225 *See* Bonfield, Exh. SJB-5T.

- Affordability of Avista's bills – Avista is focused on addressing the affordability of its bills, the Commission should continue to consider affordability in its decision making, and Avista's bills with the proposed increases in this case will remain affordable.[226]
- Disconnection Policies – Avista disagrees with TEP that its disconnection policies are inequitable and should be changed.[227]
- Low Income Needs Assessment & Energy Burden Assessment – Avista does not believe a new LINA or EBA are necessary at this time. Rather, the Company's existing reporting obligations – or, for some reports, an expansion of the existing metrics or information – provide much of the information that TEP and NWEC suggest providing. The Company is committed to continue discussions with its Energy Assistance Advisory Group (EAAG) on future reporting needs.[228]
- Customer Demographic Data – Avista does not currently have the systems or resources required to request demographic information for all current and future distributed energy resource (DER) programs, as it does for its Low Income Rate Assistance Program (LIRAP), but is open to continued conversations with its advisory groups regarding programs for which this may be appropriate and relevant enough to warrant the time and expense involved in such a request.[229]
- Language Access – Avista is actively pursuing language access changes and opportunities and does not believe a separate language access plan is necessary.[230]
- Performance Measures Pursuant to RCW 80.28.425(7) – Avista proposes two minor modifications to the reporting of the Commission directed performance measures and continues to believe performance incentive mechanisms are not necessary in this case, which no other party objects to.[231]
- Performance Based Ratemaking Metrics – Avista proposes that the Commission adopt the Initial Reported Performance Metrics for the MYRP approved in this case from its Policy Statement Addressing Initial Reported Performance Metrics issued on August 2, 2024, in Docket U-210590.[232]
- Recurring Reporting Obligations – Avista proposes a number of changes to its recurring reporting obligations. However, based on the recommendations of other parties in this case, Avista agrees to maintain its annual Disconnection Reduction Report and COVID-19 arrearage reporting but does not agree with Staff that it should maintain its Critical Infrastructure Report.[233]
- Natural Gas Energy Efficiency – Avista does not agree with Sierra Club that it should, or can, eliminate incentives for natural gas equipment.[234]

226 *Id* at 3-10.
227 *Id*. at 10-19.
228 *Id*. at 19-28.
229 *Id*. at 28-30.
230 *Id*. at 30-34.
231 *Id*. at 34-35. Specifically, Avista proposes that the reporting of the affordability and energy burden metrics align with Commissions Policy Statement Addressing Reported Performance Metrics issued on August 2, 2024, in Docket U-210590.
232 *Id*. at 35-40.
233 *Id*. at 40-45.
234 *Id*. at 45-49.

- Decarbonization Plan & Targeted Electrification Pilot – Avista does not agree with Sierra Club that a decarbonization plan, separate from its natural gas IRP, is necessary, nor does the Company support Sierra Club's proposal that the Commission require Avista to perform a targeted electrification pilot.[235]

VIII. RATE SPREAD / RATE DESIGN

159 AWEC was the only party to take issue with the Company's filed electric cost of service study in this proceeding.[236] While AWEC took issue with certain aspects of the electric study, both the Company and AWEC study produced similar results and should be considered directionally accurate for setting rates. [237]/[238]

160 Because the results of AWEC's study largely align with the results of the Company's study, in the Company's view, the Commission does not need to "approve" either study. Both studies should be considered directionally accurate for setting rates.[239]

A. Electric Rate Spread.

161 Both the Company and AWEC acknowledge that certain rate schedules are drastically over (Schedules 11/12, 21/22 and 25) or under paying (Schedule 1) on a relative cost of service basis. To mitigate this inequity between rate schedules, the Company is supportive of making substantive movement, as proposed by AWEC, given the lower revenue requirement upon rebuttal.[240] The Company also supports AWEC's rate spread for RY2, and does not oppose a uniform percentage of revenue basis for RY2.

162 The Company does take issue, however, with other revenue spread allocations as proposed by AWEC.[241] Electric Vehicle Schedules 13 and 23 were approved in Docket UE-210182 with an

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235 *Id*. at 49-56.
236 Kaufman, Exh. LDK-1T at 3:10 – 10:14.
237 Miller, Exh. JDM-8T at Table No. 2, p. 7.
238 *Id.* at 2:23-26.
239 *Id*. at 3:2-5.
240 *Id*. at 5:14-18.
241 *Id*. at 7:13-25.

effective date of April 26, 2021. The Company expects these schedules to mature over time as EV technology continues to evolve and customers usage becomes more consistent, which the Company believes may yield more meaningful cost of service study results in future cost of service studies. The Company, therefore, proposes an equal percentage of base revenue increase to both Schedules 13 and 23, consistent with its original filing.[242]

163 Moreover, Colstrip Schedule 99 should not be factored into the rate spread allocation as proposed by AWEC.[243] Colstrip Schedule 99 is a separate and distinct tariff, which the parties previously agreed to a rate spread allocation for the term of the tariff. The Company does not believe that the revenue allocation for Schedule 99 that was agreed to in the prior settlement was otherwise meant to impact base rates in perpetuity once Colstrip costs were removed from base rates.[244]

B. Natural Gas Rate Spread.

164 Both the Company and AWEC have come to the same conclusion that certain natural gas rate schedules are grossly overpaying on a relative cost of service basis (Schedules 111/112 and 131/132) and others are grossly underpaying (Schedule 146).[245]/[246] To mitigate this inequity between rate schedules, the Company is supportive of the prescriptive movement, as proposed by AWEC.[247]

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[242] Miller, Exh. JDM-8T at 7:13-25. At the Company's rebuttal RY1 revenue requirement of $42.9 million, rate Schedule 13 would be allocated $4 thousand dollars and Schedule 23 would be allocated $5 thousand dollars.

[243] Kaufman, Exh. LDK-1T at 2:11-12.

[244] The new level of revenue related to Colstrip Schedule 99 that will be in effect beginning January 1, 2025, will not be known or approved until close to the effective date, and therefore not able to be incorporated into the rate spread from this general rate case that will go into effect on December 21, 2024. (Miller, Exh. JDM-8T at 8:1-18)

[245] The Company provided its proposed natural gas rate spread for both rate changes in Exh. JDM-1T, pp. 25-27. More detailed information is provided in Exh. JDM-7.

[246] Kaufman, Exh. LDK-1T at 12:3-4.

[247] AWEC applied a prescriptive methodology for allocating the revenue increase which does not fully allocate the entire revenue requirement to the rate schedules. The Company proposes that any un-allocated revenue requirement be applied to Schedules 111/112 and 131/132 proportionally in order to ensure the full revenue

C. Rate Design.

165 Staff recommends an increase of $1.00 to the residential basic charges under Schedule 1 for electric service and Schedule 101 for natural gas service.[248] These increases would bring the residential basic charge for electric service up to $10.00 and up to $10.50 for natural gas service.[249] The Company is willing to modify its original proposal of basic charge levels of $15.00 in RY1 and $20.00 in RY2 and reduce the increase down to the levels proposed by Commission Staff.

166 The Company supports AWEC's proposal related to the Schedule 25 demand charges, but at a lower level. [250] The Company proposes that the RY1 demand charges increase by 25% (not 50%), in alignment with the RY2 change proposed by AWEC. A 25% increase in both RY1 and RY2 will provide substantial movement towards full-cost recovery, while minimizing the variability of rate changes to individual customers on Schedule 25.[251]

167 Finally, the Company supports AWEC's proposed increase to the greater than 115 kV primary voltage discount (PVD) from $1.93 to $4.39 for Schedule 25.[252]

D. Colstrip Schedule 99 Rate Spread.

168 NWEC proposes that the Commission disregard the prior approved Full Multiparty Settlement Stipulation agreement which stated that "The costs removed from base rates will be allocated to the rate schedules through separate Tariff Schedule 99 using a proportional allocation of the RY1 base revenue spread"[253] in favor of a generation allocation that it claims better matches

requirement is allocated to the Schedules. Table No. 4 at Exh. JDM-8T at 12, summarizes the rate spread allocation to the rate schedules at the revenue requirement levels proposed by the Company.

248 Hillstead, Exh. KMH-1T at 27:14-15.

249 *Id*. at 12:10-18.

250 Kaufman, Exh. LDK-1T at 17:13-16.

251 Miller, Exh. JDM-8T at 15:3-11.

252 Miller, Exh. JDM-8T at 16:5-8.

253 Docket Nos. UE-220053 UG-220054 and UE210854 (consolidated), P. 14, Subsection. C.

cost of service principals. NWEC was a party to the Full Multiparty Settlement Stipulation, which should be honored.[254]/[255]

E. Line Extension Allowance.

169 The Company does not oppose NWEC's proposal related to the line extension allowances for non-residential customers in this proceeding.[256] Sierra Club promotes a concept that would not allow for an electric line extension allowance for customers installing natural gas or propane.[257] This unreasonable policy shift should be rejected in this case.[258] Consideration of such a broad policy matter (which would have far-reaching implications on fuel choice for customers) should be addressed elsewhere.

IX. CONCLUSION

170 Avista appreciates the opportunity to present several important issues in need of resolution, including a recognition of the changed power supply landscape, necessary changes to the ERM and the need to preserve the intended objectives of the MYRP by rejecting a call for a one-year only plan and any departure from the "portfolio" approach to provisional capital recovery.

RESPECTFULLY SUBMITTED this 28th day of October, 2024.

AVISTA CORPORATION

By:____________________________
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Avista Corporation

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254 Miller, Exh. JDM-8T at 17:15-18.

255 As part of that testimony, the Joint Parties stated "As discussed in the Settlement at page 6, subsection a), these costs would be allocated to the rate schedules in Tariff Schedule 99 using a proportional allocation of the Rate Year 1 base revenue spread. <u>This allocation will be used for the life of the rate schedule.</u>" (Dockets UE-220053, UG-220054 and UE-210854 (Consolidated), Supplemental Joint Testimony, pg. 9, lines 27-29, emphasis added)

256 Miller, Exh. JDM-8T at 17:15-18. NWEC proposes to discontinue line extension allowances for Schedules 131, 132, and 146 effective January 1, 2025. (Gehrke, Exh. WG-1T at 10:14-15) In addition, NWEC recommends that the Company no longer offer service under tariff Schedule 154. (*Id.* at 10:14-15)

257 Dennison, Exh. JAD-1T, at 13:16-18.

258 Miller, Exh. JDM-8T at 18:7-17.