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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF AVISTA CORPORATION FOR THE AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC AND NATURAL GAS SERVICE TO ELECTRIC AND NATURAL GAS CUSTOMERS IN THE STATE OF IDAHO	)	CASE NO. AVU-E-23-01 CASE NO. AVU-G-23-01 DIRECT TESTIMONY OF KAYLENE J. SCHULTZ

FOR AVISTA CORPORATION

(ELECTRIC AND NATURAL GAS)

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I. INTRODUCTION

Q. Please state your name, present position with Avista Corporation, and business address.

A. My name is Kaylene J. Schultz. I am employed by Avista Corporation as Manager of Regulatory Affairs in the Regulatory Affairs Department. My business address is 1411 East Mission, Spokane, Washington.

Q. Would you briefly describe your educational background and professional experience?

A. Yes. I am a graduate from Gonzaga University with a Bachelor of Business Administration degree, majoring in both Accounting and Business Administration, with a concentration in Management Information Systems. After spending nearly eight years in the banking and capital markets sector, I joined Avista in September 2015 as a Natural Gas Analyst in the Company's Gas Supply Department, now Energy Supply. In January 2019, I joined the Regulatory Affairs Department as a Regulatory Affairs Analyst where I was responsible for preparing various annual filings and applications. In my current role as Manager of Regulatory Affairs, my primary areas of responsibility include preparation of general rate case filings, annual power supply-related filings, among other things.

Q. What is the scope of your testimony in this proceeding?

A. My testimony and exhibits in this proceeding will cover accounting and financial data in support of the Company's Two-Year Rate Plan for the period September 1, 2023 through August 31, 2025. I will explain pro formed operating results, including expense and rate base adjustments made to actual operating results and rate base. In addition, I incorporate the Idaho-share of the proposed adjustments of other witnesses in this case.

Q. Are you sponsoring any exhibits to be introduced in this proceeding?

A. Yes. I am sponsoring Exhibit No. 4, Schedule 1 (Electric) and Schedule 2 (Natural Gas), which were prepared under my direction. These exhibits consist of worksheets, which show actual twelve months-ended June 30, 2022 operating results, pro forma, and proposed electric and natural gas operating results and rate base for the State of Idaho for Rate Year 1 (September 1, 2023 through August 31, 2024) and Rate Year 2 (September 1, 2024 through August 31, 2025). The exhibits also show the calculation of the general revenue requirement, the derivation of the Company's overall proposed rate of return, the derivation of the net-operating-income-to-gross-revenue-conversion factor, and the specific pro forma adjustments proposed in this filing for each Rate Year 1 and Rate Year 2.

Q. Would you please summarize your direct testimony?

A. Yes. Below is a summary of the principal topics discussed in my direct testimony:

- The Company is requesting a Two-Year Rate Plan with Rate Year 1 <u>electric</u> base rate relief of $37.462 million, or 13.6% (14.7% on a billed basis), effective September 1, 2023. The Company is also requesting Rate Year 2 electric base rate relief of $13.150 million or 4.2% (4.5% on a billed basis), effective September 1, 2024.

- The Company is requesting a Two-Year Rate Plan with Rate Year 1 <u>natural gas</u> base rate relief of $2.771 million, or 6.0% (2.7% on a billed basis), effective September 1, 2023. The Company is requesting Rate Year 2 natural gas base rate relief of $120,000 or 0.3% (0.1% on a billed basis), effective September 1, 2024.

- The Company has pro formed in this case capital additions for the period July 31, 2022 through August 31, 2025. These capital additions, along with changes in power supply, are the primary drivers of the Company's request for rate relief.

- As discussed by Company witness Ms. Benjamin, on or before February 22, 2023 the Company will file electric and natural gas applications requesting Commission approval of the Company's proposed changes in depreciation rates, per the Depreciation Study sponsored by Company witness Mr. Spanos. The

> Company has included the effect of the proposed change in depreciation rates effective September 1, 2023, resulting in a reduction to its electric and natural gas revenue requirements of approximately $1.5 million for electric and $325,000 for natural gas, for net plant investment as of August 31, 2023.[1]

II. COMBINED REVENUE REQUIREMENT SUMMARY – TWO-YEAR RATE PLAN: SEPTEMBER 1, 2023 THROUGH AUGUST 31, 2025

Q. Please describe the Company's Two-Year Rate Plan proposed for the period September 1, 2023 through August 31, 2025.

A. The Company is proposing a Two-Year Rate Plan for the period September 1, 2023 through August 31, 2025. For both electric and natural gas, the Company is proposing an increase for Rate Year 1 effective September 1, 2023 (hereafter "RY1"), and Rate Year 2 effective September 1, 2024 (hereafter "RY2"). The Company is proposing a Two-Year Rate Plan to avoid annual rate cases in its Idaho jurisdiction, providing benefits to all stakeholders. It provides benefits to our customers by providing a level of rate certainty over this two-year period; relief to all stakeholders – customers, the Commission and its Staff, intervenors, and the Company - from the administrative burdens and costs of litigation of annual general rate cases; and to Avista by providing a two-year window to manage its business in order to have an opportunity to achieve a fair rate of return.[2]

Q. Please explain why it is so important to establish a reasonable and sufficient first year revenue requirement.

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[1] The Company will file Depreciation Applications/Petitions in each of Avista's Jurisdictions by service on or before February 22, 2023, as allocated depreciation rates need approval of all three Jurisdictions (Idaho, Washington and Oregon) prior to implementation in each State.

[2] The Two-Year Rate Plan would not preclude tariff filings authorized by or contemplated by the terms of the Power Cost Adjustment (PCA), Purchased Gas Adjustment (PGA), Public Purpose Rider Adjustment (DSM) or similar and customary rate adjustments. The Company is proposing that the Two-Year Rate Plan also not preclude the Company from filing for rate relief or accounting treatment for major changes in costs not reflected in this filing, such as the potential for changes in corporate tax rates, or new safety or reliability requirements imposed by regulatory agencies.

A. In any multiyear rate plan, the first-year revenue requirement approved by a commission will persist for each year of the rate plan and is the basis for additional revenue adjustments in years 2, 3 and beyond. If the revenue requirement is sufficient for the first year of the plan, and the next year is built off of that revenue requirement, the utility would have a reasonable opportunity to earn its allowed rate of return. However, if the first-year revenue requirement is insufficient, that insufficiency will persist for the length of the rate plan.

Q. Please provide a summary of the Two-Year Rate Plan results included in the Company's Idaho electric and natural gas operating pro forma studies.

A. After considering all standard Commission Basis adjustments, as well as additional pro forma and normalizing adjustments, the pro forma electric and natural gas rates of return ("ROR") for the Company's Idaho jurisdictional operations are 4.74% and 6.53%, respectively for RY1, ending August 31, 2024. After considering additional incremental pro forma adjustments for RY2, ending August 31, 2025, the pro forma electric and natural gas ROR are 3.87% and 6.51%, respectively. These return levels, especially for electric operations, are well below the Company's requested rate of return of 7.59%.[3] Table No. 1 below provides a summary of the RY1 and RY2 Rates of Return per the pro forma studies versus that proposed by the Company.

[3] Current authorized ROR for both Idaho electric and natural gas is 7.05%.

Table No. 1 – Rates of Return before Rate Relief

Two Year Rate Plan Rates of Return			
Service	**RY1 Pro Forma**	**RY2 Pro Forma**	**Proposed**
Idaho Electric	4.74%	3.87%	7.59%
Idaho Natural Gas	6.53%	6.51%	7.59%

Further, Illustration Nos. 1 and 2 below, show the ROR for Idaho electric and natural gas operations for (1) actual as of 12ME June 30, 2022; (2) restated as of 12ME June 30, 2022; (3) RY1 12ME August 31, 2024; (4) RY2 12ME August 31, 2025; and (5) requested.

Illustration No. 1: Two-Year Rate Plan – Electric Rates of Return

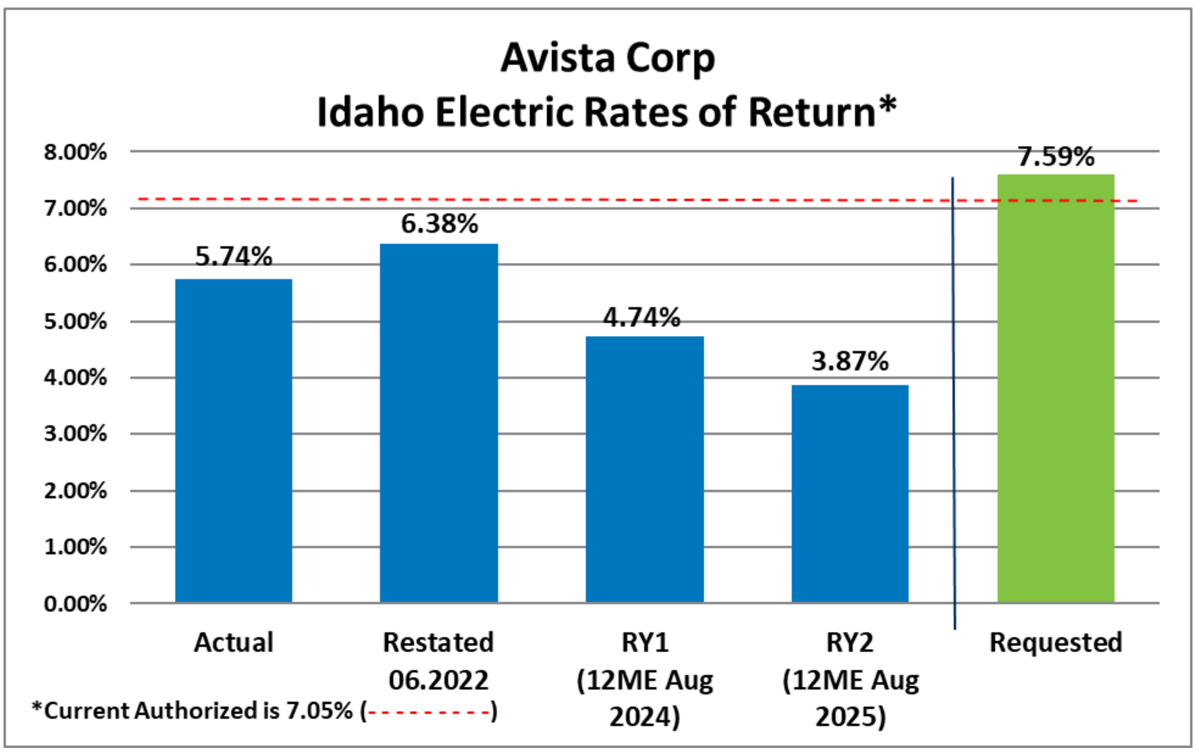
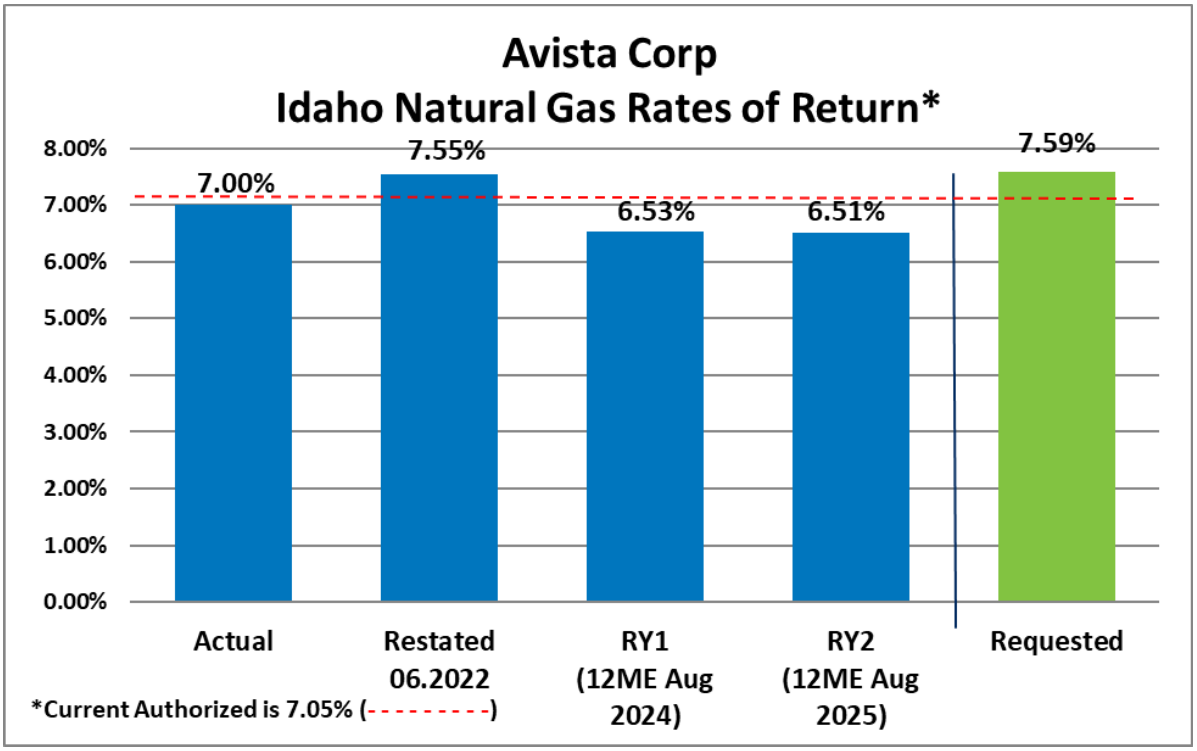


Illustration No. 2: Two-Year Rate Plan – Natural Gas Rates of Return



The incremental revenue requirement necessary to give the Company an opportunity to earn its requested ROR in RY1 is $37,462,000 or 13.6% base (14.7% billed) for its electric operations, and $2,771,000 or 6.0% base (2.7% billed) for its natural gas operations. The incremental revenue requirement necessary to give the Company an opportunity to earn its requested ROR in RY2 is $13,150,000 or 4.2% base (4.5% billed) for its electric operations, and $120,000 or 0.3% base (0.1% billed) for its natural gas operations. Table No. 2 below provides a summary of the RY1 and RY2 requested revenue requirement and percentage increases.

<u>Table No. 2 – Revenue Requirement and Percentage Increases</u>

Two Year Rate Plan Revenue Requirement ($ 000's) & Percentage Increases				
Service	**RY1**		**RY2**	
	Revenue	**Base %**	**Revenue**	**Base %**
Idaho Electric	$ 37,462	13.6%	$ 13,150	4.2%
Idaho Natural Gas	$ 2,771	6.0%	$ 120	0.3%

Q. What are the Company's rates of return that were last authorized by this Commission for its electric and natural gas operations in Idaho?

A. As shown in Illustration Nos. 1 (electric) and 2 (natural gas), as depicted by the horizontal red dashed line, the Company's last authorized rate of return for its Idaho electric and natural gas operations was 7.05%, effective September 1, 2021, per Case Nos. AVU-E-21-01 and AVU-G-21-01.

Q. What are the primary factors driving the Company's need for electric and natural gas increases?

A. The primary factor driving the Company's electric and natural gas revenue requirements in RY1 and RY2 is an increase in net plant investment (including return on investment, depreciation and taxes, and offset by the tax benefit of interest) from that currently authorized. For RY1 and RY2, electric net power supply expenses also contribute significantly to the incremental electric revenue requirement. Other changes impacting the Company's revenue requirement requests relate to increases in distribution, operation and maintenance (O&M), and administrative and general (A&G) expenses for both electric and natural gas operations, compared to current authorized levels.

Q. What are the major components of the increased plant investment included in the Company's RY1 and RY2 electric and natural gas results?

A. Looking at the changes to "gross" plant in service for RY1, Idaho "gross" plant increases by approximately $240.6 million for electric, and approximately $45.6 million for natural gas, as compared to what is currently embedded in base retail rates.[4] For RY2, "gross" plant increases by approximately $83.5 million for electric, and approximately $11.9 million for natural gas, as compared to RY1. A breakdown of the incremental electric and natural gas gross plant additions, for each year, is shown in Table No. 3 as follows:

Table No. 3 – Gross Plant Additions

Gross Plant Additions (000s)			
	Electric		
Investment	RY1[1]	RY2[2]	Total Over 2-YR Plan
Generation/Transmission	$ 69,440	$ 26,272	$ 95,712
Distribution	$ 131,261	$ 46,325	$ 177,586
General & Intangible	$ 39,918	$ 10,859	$ 50,777
Total Electric Gross Additions	$ 240,619	$ 83,456	$ 324,075
Net Plant Additions	$ 148,250	$ 36,752	$ 185,002
	Natural Gas		
Investment	RY1[1]	RY2[2]	Total Over 2-YR Plan
Distribution	$ 41,077	$ 11,503	$ 52,580
General & underground Storage	$ 4,522	$ 353	$ 4,875
Total Natural Gas Gross Additions	$ 45,599	$ 11,856	$ 57,455
Net Plant Additions	$ 32,708	$ 4,947	$ 37,655

[1]RY1 - Effective September 1, 2023 - August 31, 2024
[2]RY2 - Effective September 1, 2024 - August 31, 2025

The specific 2022 through August 2025 pro forma capital investments undertaken by the Company to expand and replace its generation, transmission, distribution and general facilities are discussed further by Company witnesses Mr. Kinney regarding production investment (including the Company's investment in Colstrip Units 3 and 4), Mr. DiLuciano regarding transmission, distribution and general investment, Mr. Kensok regarding the costs

[4] Current embedded base retail rates include most net plant additions through December 31, 2021 for electric and natural gas base rates.

associated with Avista's IS/IT projects, Mr. Howell regarding Wildfire Plan investments, and Ms. Hydzik regarding customer technology projects.

Ms. Benjamin sponsors the restating and pro forma capital adjustments, which incorporate the effects of these capital investments in the determination of the Company's proposed revenue requirements.[5]

Q. Would you please provide additional details related to the changes in power supply costs and transmission revenues?

A. Yes. As discussed in Company witness Mr. Kalich's testimony, the level of Idaho's share of power supply expense effective with RY1 has increased by approximately $10.3 million ($29.8 million on a system basis) from the level currently included in base rates. For RY2, Idaho's share of net power supply expense has increased by approximately $4.6 million ($13.2 million on a system basis) above RY1 levels.

In addition, as discussed by Company witness Mr. Dillon, effective with RY1, the level of Idaho's share of pro forma transmission revenues increased $2.9 million ($8.4 million on a system basis) from the level currently included in base rates. Idaho pro forma transmission revenue, however, decreases by $335,000 ($880,000 on a system basis) in RY2, versus that included in RY1.[6]

Therefore, the net change in power supply expense and transmission revenues result in an overall net increase in electric costs of approximately $7.4 million in RY1 and $4.3 million in RY2.

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[5] With the exception of the Pro Forma Colstrip Unit 3 and 4 investment and regulatory amortization included in Pro Forma Adjustments 3.17 discussed and sponsored by Ms. Andrews. The Colstrip Unit 3 and 4 generation capital additions in 2022 are discussed and sponsored by Mr. Kinney.

[6] See Mr. Dillon's direct testimony, footnotes 3 and 4.

Q. Please identify the main components of the distribution, O&M and A&G expense changes included in the Company's filing.

A. Although the Company has a series of increases in expenses, for electric operations these increases are largely due, in part, to changes in costs associated with the Company's Wildfire Plan expenses and increases in insurance related to higher premiums, as a result of wildfires across the country. In addition, for both electric and natural gas operations, other increases are a result of increases in labor and benefits, as well as other operating expenses that have seen increases as a result of higher inflationary pressures experienced across the Company's operations. To recognize these cost changes, the Company has included a number of pro forma adjustments for RY1 and RY2 to capture the net increases the Company will experience from the twelve-months ending June 30, 2022 test year.

III. DERIVATION OF TWO-YEAR RATE PLAN REVENUE REQUIREMENT

Test Period for Ratemaking Purposes

Q. On what test period is the Company basing its need for additional electric and natural gas revenue?

A. The test period being used by the Company is the twelve-month period ending (12ME) June 30, 2022, presented on a 12ME August 31, 2024 and August 31, 2025 pro forma basis. Current authorized electric and natural gas rates for the existing two-year rate plan effective September 1, 2021, were based upon the 12ME December 31, 2019 test year utilized in Case Nos. AVU-E-21-01 and AVU-G-21-01, respectively, adjusted on a pro forma basis.

<u>Revenue Requirement – Rate Year 1 (RY1) & Rate Year 2 (RY2)</u>

Q. Would you please explain what is shown in Exhibit No. 4, Schedules 1 and 2?

A. Yes. Exhibit No. 4, Schedules 1 and 2, show actual and pro forma (RY1 and RY2) electric and natural gas operating results and rate base for the test period for the State of Idaho.

Column (b) of <u>page 1</u> of Exhibit No. 4, Schedules 1 and 2, show 12ME June 30, 2022 actual operating results and components of the average-of-monthly-average (AMA) rate base as recorded[7]; column (c) is the total of all adjustments to net operating income and rate base to reflect RY1 results; and column (d) is the RY1 pro forma results of operations, all under existing rates. Column (e) shows the revenue increase required which would allow the Company to earn a 7.59% rate of return for RY1. Column (f) reflects RY1 pro forma operating results with the requested increase of $37,462,000 for electric and $2,771,000 for natural gas.

<u>Page 2</u> of Exhibit No. 4, Schedules 1 and 2, show similar columns starting with RY1 (09.2023 effective) pro forma results (equal to column (d) on page 1 of Exhibit No. 4, Schedules 1 and 2), reflecting operating results and components of rate base for RY1 results, in column (b). Column (c), of page 2, is the total of all adjustments to net operating income and rate base to reflect RY2 results; and column (d) is the RY2 (09.2024 effective) pro forma results of operations, all under existing rates. Column (e) and (f) shows the revenue increases required in RY1 and RY2 to allow the Company to earn a 7.59% rate of return for

[7] Actual <u>plant</u> rate base (cost, accumulated depreciation (A/D) and accumulated deferred federal income taxes ("ADFIT") uses the 06.2022 AMA balances. Plant rate base is adjusted to 08.2024 AMA basis for RY1, and 08.2025 AMA basis for RY2, with restating and pro forma adjustments.

RY2. Column (g) reflects RY2 pro forma operating results with the requested increases of $13,150,000 for electric and $120,000 for natural gas, above that requested in RY1.

Q. Would you please explain page 3 of Exhibit No. 4, Schedules 1 and 2?

A. Yes. Page 3 of Exhibit No. 4, Schedule 1, shows the RY1 and RY2 revenue requirement calculations for electric of $37,462,000 and $13,150,000, respectively. Page 3 of Exhibit No. 4, Schedule 2, shows the RY1 and RY2 revenue requirement calculations for natural gas of $2,771,000 and $120,000, respectively.

Q. What does page 4 of Exhibit No. 4, Schedules 1 and 2 show?

A. Page 4 shows the proposed Cost of Capital and Capital Structure utilized by the Company in this case, and the weighted average cost of capital of 7.59%. Company witness Mr. Thies discusses the Company's proposed rate of return and the pro forma capital structure utilized in this case, while Company witness Mr. McKenzie provides additional testimony related to the appropriate return on equity for Avista.

Q. Please explain page 5 of Exhibit No. 4, Schedules 1 and 2.

A. Page 5 shows the derivation of the net-operating-income-to-gross-revenue-conversion factor of 0.787006. The conversion factor includes uncollectible accounts receivable, Commission fees and Idaho State income taxes.[8] Federal income taxes are reflected at 21%.

Q. Now turning to pages 6 through 11 of Exhibit No. 4, Schedules 1 and 2, please explain what those pages show.

A. Page 6 begins with actual operating results and rate base for the test period in column (1.00). Individual Commission Basis normalizing and restating adjustments that are

[8] Due to net operating loss (NOL) carryforwards, the Company anticipates it will pay the minimum state income tax in Idaho through 2025.

standard components of general rate case filings begin in column (1.01) and continue through column (2.13) on page 7 for electric, and column (2.10) on page 7 for natural gas.

For electric, Exhibit No. 4, Schedule 1, individual pro forma adjustments for RY1 begin in column (3.00P) on page 8 and go through column (3.17) on page 9, with the "RY1 09.2023 FINAL TOTAL" column on page 9 representing the total pro forma operating results and net rate base for the RY1 pro forma period (effective 09.2023). Page 10 of Exhibit No. 4, Schedule 1, includes RY2 pro forma adjustment columns (24.00P) through (24.07). Additional RY2 pro forma adjustment columns (24.08) and (24.09) are shown on page 11, along with the "RY2 09.2024 FINAL TOTAL" and "RY2 INCREMENTAL 09.2024I Above 09.2023 TOTAL" columns, representing the total pro forma operating results and net rate base for the RY2 pro forma period (effective 09.2024), and the incremental balances above the RY1 pro forma rate year.

For natural gas, at Exhibit No. 4, Schedule 2, individual pro forma adjustments for RY1 are listed on page 8, column (3.01) through page 9, column (3.15), with the "RY1 09.2023 FINAL TOTAL" column on page 9 representing the total pro forma operating results and net rate base for the RY1 pro forma period (effective 09.2023). Page 10 of Exhibit No. 4, Schedule 2, includes RY2 pro forma adjustment columns (24.01) through (24.06). Additional RY2 pro forma adjustment columns (24.07) and (24.08) are shown on page 11, along with the "RY2 Rate Change Total 09.2024 FINAL TOTAL" and "RY2 INCREMENTAL 09.2024I Above 09.2023 TOTAL" columns, representing the total pro forma operating results and net rate base for the RY2 pro forma period (effective 09.2024), and the incremental balances above the RY1 pro forma rate year.

IV. STANDARD COMMISSION BASIS AND RESTATING ADJUSTMENTS

Q. Please explain each of the standard Commission basis and restating adjustments.

A. The following adjustments are consistent with current regulatory principles and the manner in which they have been addressed in recent cases (i.e., AVU-E-21-01 and AVU-G-21-01), unless otherwise noted. Columns following the Results of Operations column (1.00) reflect restating adjustments necessary to: restate the actual results based on prior Commission orders; reflect appropriate annualized expenses and rate base; correct for errors; or remove prior period amounts reflected in the actual results of operations. In addition to the explanation of adjustments provided herein, the Company has also provided workpapers, both in hard copy and electronic formats, outlining additional details related to each of the adjustments. A summary of each adjustment follows:

Electric Adjustment (1.01) and Natural Gas Adjustment (1.01) – **Accumulated Deferred FIT Rate Base**, adjusts the electric and natural gas accumulated deferred federal income tax (ADFIT) rate base balance included in the Results of Operations column (1.00) to the adjusted ADFIT balance reflected on an AMA basis, as shown within my workpapers provided with the Company's filing. ADFIT reflects the deferred tax balances arising from timing differences between book recognition and tax recognition of certain income and deductions. The primary deductions that have timing differences, and therefore associated ADFIT, are accelerated tax depreciation over book depreciation and the repairs deduction.

The effect of these adjustments on Idaho rate base is a reduction of $1,420,000 electric, and an increase of $785,000 natural gas. The effect on Idaho net operating income (NOI) due to the Federal Income Tax (FIT) expense on the restated level of interest on the change in rate base[9] is a reduction of $7,000 for electric and an increase of $4,000 for natural gas.

Electric Adjustment (1.02) and Natural Gas Adjustment (1.02) - **Deferred Debits and Credits**, is a consolidation of previous Commission Basis or other restating rate base adjustments and their NOI impact. The net impact on a consolidated basis of this adjustment decreases Idaho electric NOI by $71,000 and increases natural gas NOI by $79,000. No adjustment is necessary for Idaho electric or natural gas rate base.

Adjustments included in the Deferred Debits and Credits consolidated adjustment are those necessary to reflect restatements from 12ME June 30, 2022 actual results (included in column 1.00 "Per Results of Operations"), based on prior Commission orders as explained below.

- **Colstrip Common AFUDC** is also associated with the Colstrip plants in Montana, and increases rate base. Differing amounts of Colstrip common facilities were excluded from rate base by this Commission and the Washington Utilities and Transportation Commission (WUTC) until Colstrip Unit 4 was placed in service. The Company was allowed to accrue AFUDC on the Colstrip common facilities during the time that they were excluded from rate base. It is necessary to directly assign the AFUDC because of the differing amounts of common facilities excluded from rate base by this Commission and the WUTC. In September 1988, an entry was made to comply with a Federal Energy Regulatory Commission (FERC) Audit Exception, which transferred Colstrip common AFUDC from the plant accounts to Account 186. These amounts reflect a direct assignment of rate base for the appropriate average-of-monthly-averages amounts of Colstrip common AFUDC to the Idaho and Washington jurisdictions. Amortization expense associated with the Colstrip common AFUDC is charged directly to the Idaho and Washington jurisdictions through Account 406 and is a component of the actual results of operations.

- **Boulder Park Disallowance** reflects the Boulder Park plant disallowance ordered by the IPUC in Case No. AVU-E-04-1. The IPUC disallowed a rate of return on $2,600,000 million of investment in Boulder Park. The disallowed investment, and related A/D and ADFIT are removed. These amounts are a component of actual results of operations.

- **Restating Montana Riverbed Lease** reflects the costs associated with the Montana Riverbed lease settlement. In the Montana Riverbed lease settlement, the Company agreed

[9] The net effect of FIT expense on the restated level of interest expense due to a change in rate base is shown within <u>each</u> individual adjustment.

to pay the State of Montana $4.0 million annually beginning in 2007, with annual inflation adjustments, for a 10-year period for leasing the riverbed under the Noxon Rapids Project and the Montana portion of the Cabinet Gorge Project. The first two annual payments were deferred by Avista as approved in Case No. AVU-E-07-10. In Case No. AVU-E-08-01 (see Order No. 30647), the Commission approved the Company's accounting treatment of the deferred payments, including accrued interest, to be amortized over the remaining eight years of the agreement starting October 1, 2008. The 10-year amortization of the first two annual payment deferral expired on September 31, 2016, therefore there is no rate base balance. The lease continues on a year-to-year basis, with payments being paid into escrow until resolution of pending litigation. The Company has included lease expense, increased for annual inflation through 2022 as previously required, increasing expense by $56,000.

- **Weatherization and DSM Investment** includes in rate base the Sandpoint weatherization grant balance (FERC account 124.350). Beginning in July 1994, accumulation of AFUCE[10] ceased on Electric DSM and full amortization began on the balance based on the measure lives of the investment. Beginning in 1995, the amortization rates were accelerated to achieve a 14-year weighted average amortization period, which was completed in 2010. Remaining as an Idaho rate base item is the weatherization loan balance of approximately $59,000.

- **Customer Advances** decreases rate base for funds advanced by customers for line extensions, as they will be recorded as contributions-in-aid-of-construction at some future time. This adjustment is a component of the actual results of operations.

Finally, this adjustment removes non-reoccurring deferral expenses included in the 12ME June 30, 2022 test period associated with the Wildfire Resiliency Depreciation for electric of $34,000, the AFUDC Equity deferred federal income taxes (DFIT) Deferral expense for natural gas of $19,000, and the Natural Gas Depreciation Study Deferral for natural gas of $81,000. In summary, as noted above, the net impact on a consolidated basis of this adjustment decreases Idaho electric NOI by $71,000 and increases natural gas NOI by $79,000. No adjustment is necessary for Idaho electric or natural gas rate base.

Electric Adjustment (1.03) and Natural Gas Adjustment (1.03) - **Working Capital**, restates the working capital balance reflected in the Company's Results of Operations column (1.00) on a 12ME June 30, 2022 test period AMA basis, to the adjusted working

[10]Allowance for funds used to conserve energy.

capital balance. The Company uses the Investor Supplied Working Capital (ISWC) methodology to calculate the amount of working capital reflected in its actual results of operations. This method is consistent with that incorporated in the Company's last electric and natural gas general rate cases, Case Nos. AVU-E-21-01 and AVU-G-21-01, respectively, and was used for both electric and natural gas results.[11] The impact of this adjustment resulted in an increase to electric rate base of $133,000 and a decrease to natural gas rate base of $193,000. This adjustment also increases electric NOI by $1,000 and decreases natural gas NOI by $1,000, due to the impact of debt interest.

Electric Adjustment (1.04) and Natural Gas Adjustment (1.04) - **Restate Capital 06.2022 EOP,** restates the capital investment and expenses associated with adjusting the 12ME June 30, 2022 AMA plant related balances to June 30, 2022 end-of-period (EOP) balances. Ms. Benjamin sponsors and describes in detail this adjustment within her testimony. The overall net effect of Adjustment (1.04) on Idaho rate base is an increase of $36,690,000 for electric and $4,001,000 for natural gas. The effect on Idaho NOI are increases of $190,000 for electric and $21,000 for natural gas related to the federal income tax effect of debt interest.

Electric Adjustment (2.01) and Natural Gas Adjustment (2.01) - **Eliminate B & O Taxes**, eliminates the revenues and expenses associated with local business and occupation

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[11] Minor modifications were made in the Company's electric Case No. AVU-E-19-04 and the methodology has been consistent since. As discussed in electric Case No. AVU-E-19-04, as a result of the Company's Washington general rate case (Dockets UE-170485 and UG-170486), the Company agreed to two changes that better reflect the level of working capital for Avista as follows: 1) reclassified certain interest-bearing accounts to investments and 2) changed the methodology for allocating certain working capital to non-utility operations. Prior to 2018, the investment in non-utility property was used to determine the allocation. Beginning in 2018, the updated method uses all non-rate base investments to determine the allocation. Reflecting these same changes consistently between Idaho and Washington allows for administrative efficiencies when recording working capital within the Company's jurisdictional results of operations. This method is consistent with that utilized in Case Nos. AVU-E-19-04, AVU-E-21-01, and AVU-G-21-01.

(B & O) taxes, which the Company passes through to its Idaho customers. The effect of this adjustment increases electric NOI by $4,000 and natural gas NOI by $1,000.

Electric Adjustment (2.02) and Natural Gas Adjustment (2.02) - **Uncollectible Expense**, restates the accrued expense to the actual level of net write-offs for the test period. The effect of this adjustment increases electric and natural gas NOI by $124,000 and $33,000, respectively.

Electric Adjustment (2.03) and Natural Gas Adjustment (2.03) - **Regulatory Expense**, restates recorded test period regulatory expense to reflect the IPUC assessment rates applied to expected revenues for the test period and the actual levels of FERC fees paid during the test period. The effect of this adjustment reduces electric and natural gas NOI by $80,000 and $31,000, respectively.

Electric Adjustment (2.04) and Natural Gas Adjustment (2.04) - **Injuries and Damages**, is a restating adjustment that replaces the accrual with the six-year rolling average of actual injuries and damages payments not covered by insurance. This methodology was accepted by the Idaho Commission in Case No. WWP-E-98-11 and has been used since that time. The effect of this adjustment increases electric NOI by $130,000 and natural gas NOI by $16,000.

Electric Adjustment (2.05) **FIT/DFIT/ITC Expense**, and Natural Gas Adjustment (2.05) **FIT/DFIT Expense**, require no change from test period results. Test period results for FIT uses taxable income (jurisdictional results adjusted for Schedule M adjustments) calculated at the 21% federal income tax rate. DFIT expenses include federal taxes for normalized and flow-through federal tax adjustments. In addition, for electric, the income tax expense reflects the appropriate level of investment tax credits on qualified electric generation.

Electric Adjustment (2.06) and Natural Gas Adjustment (2.06) - **SIT/SITC Expense**, adjusts Idaho State Income Tax (SIT) expense and Idaho State Investment Tax Credits (SITC) applicable to Idaho electric and natural gas operations as recorded. This approach is consistent with that approved in the Company's last electric and natural general rate cases, Case Nos. AVU-E-21-01 and AVU-G-21-01. This adjustment removes prior period tax settlements and leaves SIT expense and SITC expense at the test period level. Because the Company has net operating loss carryforwards, the Company expects to incur no SIT expense through 2025. Therefore, the Company has zeroed out the SIT level in the conversion factor. The effect on Idaho NOI is a reduction of $58,000 for electric and $10,000 for natural gas.

Electric Adjustment (2.07) and Natural Gas Adjustment (2.07) - **Revenue Normalization**, is an adjustment accounting for known and measurable changes that include 1) revenue normalization which reprices customer usage using the current authorized base rates, 2) weather normalization, 3) an unbilled revenue calculation, and 4) eliminating the deferred revenue associated with the Fixed Cost Adjustment (FCA) mechanism during the test year recorded in results. For the electric adjustment, adder schedules, such as, Schedule 59 Residential Exchange, Schedule 75 Fixed Cost Adjustment, Schedule 76 Tax Customer Credit, Schedule 91 Public Purpose Tariff Rider, and Schedule 95 Optional Renewable Power, are excluded from pro forma revenues, and the related amortization expense is eliminated as well. For the natural gas adjustment, all revenues and expenses associated with the Purchased Gas Cost Adjustment Schedule 150 have been removed from the Company's filing. In addition, revenues such as those associated with the temporary Gas Rate Adjustment Schedule 155, Schedule 176 Tax Customer Credit, Schedule 178 Deferred Credits, Schedule 175 Fixed Cost Adjustment, and Schedule 191 Public Purpose Tariff

Rider are excluded from pro forma revenues, and the related amortization expenses are eliminated as well. Company witnesses Mr. Garbarino (electric) and Mr. Anderson (natural gas) sponsor these two adjustments. The effect of this adjustment increases electric and natural gas NOI by $10,761,000 and $1,226,000, respectively.

Electric Adjustment (2.08) and Natural Gas Adjustment (2.08) - **Miscellaneous Restating** removes a number of non-operating or non-utility expenses associated with advertising, dues and donations, etc., included in error, and removes or restates other expenses incorrectly charged between service and or jurisdiction. The net effect of this adjustment increases electric NOI by $5,000 and natural gas NOI by $8,000.

Electric Adjustment (2.09) and Natural Gas Adjustment (2.09) - **Restate Incentives,** restates actual O&M incentive compensation included in the Company's 12ME June 30, 2022 test period to reflect a six-year average (2016-2021) of actual payout amounts.

For <u>non-executive employees,</u> the six-year average of incentive compensation expense payout is $5.8 million (system) for O&M metrics designed to drive cost-control, and delivery of safe, reliable service with a high level of customer satisfaction. For <u>executive officers</u>, the six-year average expense payout of O&M metrics related to efficiencies in cost management (O&M cost-per-customer), customer service and reliability have averaged approximately $1.03 million (system) in operating expenses. Incentive compensation related to financial metrics are excluded from the Company's filing with expenses borne by shareholders. The net effect of this adjustment, including both non-executive and executive changes, increases Idaho NOI by approximately $390,000 for electric and $92,000 for natural gas.

Q. Please provide an overview of the Company's non-executive employee short-term incentive plan ("Non-Executive Employee STIP").

A. In accordance with the Company’s overall compensation design to align elements of incentive plans among all Company employees including executives, the Non-Executive Employee STIP plan has essentially the same stated goals as the Short-Term Incentive Plan for executives (Executive STIP). Both plans provide incentives and focus employees on stated goals, while recognizing and rewarding employees for their contributions toward achieving those goals. The components of the Non-Executive Employee STIP are all operational in nature, including cost containment on a per-customer basis. The weighting of each component is as follows: 50% O&M Cost-Per-Customer, 20% Customer Satisfaction, 20% Reliability Index and 10% Response Time.

This pay-at-risk component of compensation is part of the overall compensation for employees that is designed to be comparable with that of other similar utilities. If this pay-at-risk compensation were to be reduced or eliminated, then base pay would need to be increased in order for overall compensation to remain competitive.

Q. Please briefly describe the Executive STIP.

A. The Executive STIP is designed to align the interests of executives with both customer and shareholder interests in order to achieve overall positive operating and financial performance for the Company. The Executive STIP has four operational components, plus an earnings per share (EPS) components. The total amount associated with utility operational components is 40% and is broken down as follows: 20% O&M Cost-Per-Customer, 8% Customer Satisfaction, 8% Reliability, and 4% Response Time. The Consolidated Diluted EPS components accounts for 55% of the total opportunity and 5% Non-Regulated Activity. Only the operational components (40%) are proposed to be included in retail rates. Customers benefit from these metrics that are designed to drive cost-control, and delivery of safe, reliable service with a high level of customer satisfaction. The remaining 60% of the Executive STIP related to EPS and Non-Regulated Activity targets is borne by shareholders.

Q. What portion of the Short-Term Incentive Plans have been included in this case?

A. The Company has included 100% of the Non-Executive Employee STIP and 40% of the Executive STIP (excluding those metrics related to EPS and Non-Regulated Activity targets) in this case. All incentive compensation included in this case directly benefits customers either in cost containment and efficiencies, operationally via the reliability index and response time metrics, or customer satisfaction as measured via the Voice of the Customer Survey. By focusing employees on effective management of O&M costs, we are able to maintain or reduce charges to customers in future rate cases. The Company has excluded all incentive pay related to the EPS and Non-Regulated Activity portion of Executive STIP. In addition, a proportionate share of incentive pay for employees (in the same percentage as employee labor) related to non-utility operations has also been excluded from this case. Therefore, the appropriate portion of incentives related to Idaho utility operations has been included in this case.

Q. Please describe the Long-Term Incentive Plan (LTIP).

A. The Long-Term Incentive Plan (LTIP) is comprised of two components, which serve two different purposes.[12] Performance Shares account for 75% of the plan with metrics related to Cumulative Earnings-Per-Share (CEPS) and Total Shareholder Return (TSR). The purpose for this portion of the plan is to provide a direct link to the long-term

[12] As with all other components of the executive compensation, the Compensation Committee determines all material aspects of the long-term incentive – who receives the award, the amount of the award, the timing of the award, as well as any other aspects of the award that may be deemed material.

interests of shareholders by assuring that performance shares will be paid only if the Company attains specified financial performance levels. This portion of the plan was modified in 2014 to include both Cumulative Earnings-Per-Share (CEPS) and Total Shareholder Return (TSR). In previous years, vesting of performance-based equity awards were 100% contingent on the Company's Total Shareholder Return (TSR) relative to our peer group over a three-year period. Under the new design, two-thirds of the awards are contingent on TSR relative to our peers, and one-third is measured by our CEPS over a three-year period. The Company has <u>excluded</u> the costs associated with the Performance Share portion of the LTIP from the revenue requirement in this case.

Restricted Stock Unit (RSU) awards account for 25% of the LTIP and vesting is based on a continuation of service by the employee. The purpose for this portion of the plan is to provide an incentive for employees to remain with the Company. The long-term nature of large-scale utility projects spanning multiple years are completed more efficiently with experienced, consistent leadership. In addition, it is the Company's policy to promote from within when possible, preserving the values inherent in our culture that drive customer satisfaction, reliability of service, etc. Employees with a long tenure of employment with the Company are well versed in the Company's culture and tend to continue to cultivate the values embedded within Avista. The Company has included Idaho's share of total Company LTIP test period expense in this filing of approximately $554,000 for electric and $131,000 for natural gas.

Q. Please continue explaining the remaining restating adjustments in Exhibit 4, Schedules 1 and 2.

A. The next adjustment is Electric Adjustment (2.10) - **Idaho PCA,** which removes the effects of the financial accounting for the Power Cost Adjustment (PCA).

Under the PCA certain differences in actual power supply costs, compared to those included in base retail rates are deferred and then surcharged or rebated to customers in a future period. Revenue adjustments due to the PCA and the power cost deferrals affect actual results of operations and need to be eliminated to produce normalized results. Actual revenues and power supply costs are normalized in adjustments (2.07) Revenue Normalization and (3.01P) Power Supply, respectively. The effect of this adjustment reduces Idaho NOI by $3,111,000.

Electric Adjustment (2.11) - **Nez Perce Settlement Adjustment**, reflects a decrease in production operating expenses. An agreement was entered into between the Company and the Nez Perce Tribe to settle certain issues regarding earlier owned and operated hydroelectric generating facilities of the Company. This adjustment directly assigns the Nez Perce Settlement expenses to the Idaho and Washington jurisdictions. This is necessary due to differing regulatory treatment in Idaho Case No. WWP-E-98-11 and Washington Docket No. UE-991606. The effect of this adjustment increases Idaho electric NOI by $27,000.

Electric Adjustment (2.12) – **Colstrip/CS2 Maintenance**. As approved in Order 32371 on September 30, 2011 (in Case No. AVU-E-11-01 and AVU-G-11-01), the Company deferred the non-fuel O&M costs associated with the Company's Colstrip and Coyote Springs 2 (“CS2”) thermal generating plants. The deferral amount is the difference between actual costs and the authorized “Base O&M” costs for each respective year. Included in the historical test period level are deferrals from years 2018-2021, and RY1 includes deferrals from years 2020-2021 and estimated for 2022-2023, on a pro rata basis. In addition, the Company received insurance proceeds related to the CS2 insurance claim received in 2022[13], which were netted together with the estimated 2022 deferral.

For calendar years 2013 through 2015, the authorized system "Base O&M" expense level (established in 2013 in AVU-E-12-08) was $14.4 million. Each year deferred costs were amortized over a three-year period. For 2016, in Case No. AVU-E-15-05, the system "Base O&M" cost was adjusted upward from $14.4 million to $20.4 million, to better reflect O&M expenses in the future based on a five-year average for the period 2012-2016, and will remain at this level going forward unless adjusted. Each prior year deferred costs are amortized over a three-year period. Adjusting expense to a pro rata share of years 2023 and 2024, which include one-third of each amount deferred (actual or estimated) for calendar years 2020 through 2022 and 2021 through 2023, respectively, decreases Idaho electric expense by approximately $130,000, and increases NOI by $103,000.[14]

Electric Adjustment (2.13) and Natural Gas Adjustment (2.10) - **Restate Debt Interest**, restates debt interest using the Company's pro forma weighted average cost of debt on the Results of Operations level of rate base shown in column (1.00) only. The weighted average cost of debt is as provided in the testimony and exhibits of Mr. Thies. This adjustment results in a revised level of tax-deductible interest expense on actual test period rate base. The Federal income tax effect of the restated level of interest for the test period decreases electric NOI by $188,000 and natural gas NOI by $39,000.

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[13] In 2022, the Company received $2.5 million in insurance proceeds related to the insurance claim filed in 2018 due to the failure of equipment at the CS2 natural gas generating facility in 2018. Approximately $1.3 million of the insurance proceeds were recorded as an offset to net capital CS2 investment, with the remaining balance of approximately $1.2 million related to O&M expenses, deferred for return to Idaho and Washington customers. Idaho's share of the O&M expense amount deferred was approximately $413,000.

[14] See Pro Forma Adjustment 24.09, which adjusts Colstrip/CS2 maintenance amounts reflected in RY1, to reflect the pro rata share of years 2024 and 2025, which include one-third of each amount deferred (actual or estimated) for calendar years 2021 through 2023 and 2022 through 2024, respectively, to reflect Colstrip/CS2 maintenance amounts expected in RY2.

As noted above, the Federal income tax effect of the restated level of interest on all other rate base adjustments are included in each individual rate base adjustment described elsewhere in this testimony.

Finally, the "Restated Total" column on page 7 of Exhibit No. 4 Schedule 1, and Schedule 2, represents the results of the previous adjustments columns (1.01) through (2.13) Schedule 1 and (1.01) through (2.10) Schedule 2.

V. RY1 & RY2 - PRO FORMA ADJUSTMENTS

Q. Please explain the significance of the adjustments beginning at page 8 for Schedule 1 (electric) and Schedule 2 (natural gas) of Exhibit No. 4.

A. The adjustments on pages 8 and 9 of Exhibit No. 4, Schedule 1, and Schedule 2, are pro forma adjustments that will impact the RY1 pro forma operating period. Included on pages 10 and 11, Schedule 1 and Schedule 2 of Exhibit No. 4, are additional pro forma adjustments that will impact the RY2 pro forma operating period. These pro forma adjustments in RY1 and RY2 encompass revenue and expense items, as well as additional capital projects, bringing the operating results and rate base to the final pro forma levels for the RY1 and RY2 rate years.

In the discussion that follows, an explanation of each RY1 and RY2 pro forma adjustment is provided. The Company has also provided workpapers, both in hard copy and electronic formats, outlining additional details related to each of the adjustments. As described below and provided in accompanying workpapers, these adjustments are consistent with current regulatory principles and the treatment reflected in the last rate case, with a few proposed changes by the Company discussed below.

<u>RY1 (09.2023 – 08.2024) – Summary of Adjustments</u>

Q. Please explain each of the RY1 Pro Forma adjustments included in Exhibit No. 4, starting on page 8 of Schedule 1 and Schedule 2.

A. The first adjustment, starting on Exhibit No. 4, page 8, of Schedule 1 is Electric Adjustment (3.00P) - **Pro Forma Power Supply.** This adjustment was made under the direction of Mr. Kalich and is explained in detail in his testimony. This adjustment includes pro forma power supply related revenues and expenses to reflect the twelve-month period September 1, 2023 through August 31, 2024 using weather normalized historical loads. Mr. Kalich's testimony outlines the system level of pro forma power supply revenues and expenses that are included in this adjustment. The adjustment in column (3.00P) represents the Idaho jurisdictional share of those amounts. The net effect of this adjustment increases electric NOI by $270,000.[15 / 16]

Electric Adjustment (3.00T) - **Pro Forma Transmission Revenue/Expense,** was made under the direction of Mr. Dillon and is explained in detail in his testimony. This adjustment includes pro forma transmission-related revenues and expenses to reflect the twelve-month period September 1, 2023 through August 31, 2024. The net effect of this adjustment increases electric NOI by $1,416,000.[17]

Q. The next three electric and natural gas adjustments (3.01) through (3.03) relate to pro forma labor and benefit adjustments. Prior to addressing each of the

[15] See Pro Forma Adjustment 24.00P, which adjusts pro forma power supply amounts reflected in RY1, to reflect pro forma power supply amounts expected in RY2.
[16] As discussed by Mr. Kalich, the 2022 rates from Grant County PUD were provided to the Company after the preparation of this rate case and therefore, weren't incorporated into the modeling of this case. These updates will be incorporated when the Company updates costs prior to rates going into effect.
[17] See Pro Forma Adjustment 24.00T, which adjusts pro forma transmission-related revenues and expenses to reflect pro forma transmission-related revenue/expense amounts expected in RY2.

adjustments, please provide an overview of the Company's total compensation philosophy.

A. Avista is committed to providing total compensation to employees that will attract, motivate, and retain qualified people required to meet the needs and expectations of all utility stakeholders, including but not limited to, customers, shareholders and regulators. To that end, the Company provides employees with cash compensation (base pay and variable pay in the form of pay-at-risk incentive compensation) and a comprehensive benefit package including medical and retirement. The overall package is designed to meet the following goals:

- Clearly identify the specific measures of Company performance that are likely to create long-term value for the Company's customers and shareholders;
- Keep employees focused on cost control, customer satisfaction, reliability and operational efficiencies by awarding variable pay for meeting pre-determined metrics;
- Promote a culture of safety;
- Pay competitively compared to others within our market;
- Reward outstanding performance; and
- Align elements of the incentive plans among all Company employees, including executive officers.

Each component is carefully considered within the overall package in order to provide total compensation which will be cost-effective for the Company, as well as attract, motivate, and retain employees. Compensation components within the overall package may be adjusted over time to achieve the goal of recruiting and retaining qualified employees. The Company generally targets overall compensation levels within the range that is 15% above or below the median of Avista's peer group.

Q. Please continue with your explanation of electric and natural gas Pro Forma Adjustments (3.01) through (3.03).

A. Electric Adjustment (3.01) and Natural Gas Adjustment (3.01) – **Pro Forma Labor Non-Exec,** reflects changes in base pay, which together with pay-at-risk (Short Term Incentive Compensation described in Restate Incentive Adjustment (2.09) above) is designed to provide competitive compensation in the marketplace. The level of base pay is determined based on position qualifications such as level of education, professional designations or certifications, experience, roles and responsibilities, and within the market where we compete for talent.

Avista participates in numerous confidential salary surveys provided by third-party consulting firms, which compare Avista's pay programs and structure to other organizations in the utility industry, as well as other industries, regionally and nationally. Salary surveys are part of the input in the determination of salary increases and salary range updates (minimum, mid-point and maximum), as well as benchmarking jobs to market data. Avista benchmarks many jobs within the Company and reviews market data to determine if the salary range midpoints still accommodate the new estimated values established by the benchmarking process. The Company uses external peer group data provided by multiple surveys, and centralized in a tool named MarketPay[18] to benchmark against, and must react to external influences as they occur to remain competitive in the market and retain a qualified, high performing workforce. MarketPay enables our compensation team to quickly gather market information for similar positions in the areas we compete for talent. Based on the information provided in these surveys, salary recommendations are presented to the independent Compensation Committee of the Board of Directors for their consideration and

[18] "Payscale MarketPay is intended for global companies with large workforces, dedicated compensation teams, mature pay structures, and lots of survey data to manage. As our most advanced compensation platform, it streamlines survey management and enables native integration with Tableau." https://www.payscale.com/products/software/marketpay/

approval. The Compensation Committee can choose to grant higher or lower salary adjustments, based on the available market data.

The specific electric and natural gas adjustments reflect changes to test period union and non-union wages and salaries, excluding executive salaries, which are handled separately in Pro Forma Adjustment (3.02). For non-union employees, the adjustment annualizes the impact of the actual increase effective March of 2022 (4%) and includes the expected March 2023 increase. As of the Company's filing, the Board of Directors has approved a preliminary minimum salary increase based on salary planning surveys for 2023, with a final increase for non-union employees for 2023 to be approved early in the first quarter of 2023. The Company will update the adjustment should the actual approval be less than the minimum when approved at the Board meeting. In addition, the Company has applied an estimated prorated March 2024 increase through August 31, 2024, for total labor expense levels in RY1.[19]

Union employee increases are made in accordance with contract terms to annualize the impact of the 4% increase in 2022 and reflect the 3.5% contractually agreed increase for 2023. The current contract with the IBEW Union 77 (Idaho/Washington) expires on March 25, 2025, with the merit increase open for negotiation beyond 2023. The Company has included estimated merits for 2024 and 2025 in order to be consistent with non-union employees. The Company will update the contract agreement increase during the process of the case once it is available. In total, this adjustment represents an increase in Idaho expense in RY1, effective September 1, 2023 ending August 31, 2024, of $2.83 million electric and $0.63 million natural gas. The effect of this adjustment decreases Idaho NOI by $2,234,000

[19] See CONFIDENTIAL 3.01 & 24.04 Non-Executive Labor Adjustment workpaper, Pro-Forma Increases tab for annualized Union and Non-Union labor increases by year.

for electric and $499,000 for natural gas.[20]

Electric Adjustment (3.02) and Natural Gas Adjustment (3.02) - **Pro Forma Labor-Executive**, reflects actual salary levels approved by the Board of Directors that are in effect as of June 2022, adjusted to the expected amount for the rate-effective period. This salary level is allocated between Utility and Non-Utility based on 12ME June 30, 2022 levels actual percentages[21] (90% utility /10% non-utility). This adjustment also reflects the changes (retirements and additions) in officers and their impact on salary expense from the test period to the rate-effective period. The impact of this adjustment increases Idaho expense by $173,000 for electric and $41,000 for natural gas.

The Compensation Committee of the Board of Directors (Board) determined and approved the executive officer level of base salary effective March 2022, as with all components of executive officer compensation. The Board considers several internal factors such as individual and Company performance goals, succession planning, job complexity, experience, and breadth of knowledge in the determination of base pay. Similar to non-executive compensation, the Board also utilized external peer group data to benchmark its executives against a group of companies with similar business profiles, similar revenue size and market capitalization. These companies were reasonably assumed to be the companies with which we compete for talent. The effect of this adjustment decreases Idaho NOI by $137,000 for electric and $32,000 for natural gas.

Electric Adjustment (3.03) and Natural Gas Adjustment (3.03) - **Pro Forma Employee Benefits**, adjusts the 12ME June 30, 2022 Retirement Plans (401(k) and

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[20] See Pro Forma Adjustment 24.04, which adjusts pro forma non-executive labor amounts reflected in RY1, to reflect incremental pro forma non-executive labor amounts expected in RY2.

[21] For Executives who were new in 2022, the utility/non-utility percentages are estimated based on the previous Executives' actual allocation.

Pension), and medical insurance for active employees and for those retired (post-retirement medical) to the expected amount for RY1, effective September 1, 2023 through August 31, 2024. Annually, the Company works with independent consultants in order to determine the appropriate level of expense for both the Retirement Plans (Willis Towers Watson) and the Medical Plans (Mercer). The impact of these changes is summarized in Table No. 4 below:[22]

Table No. 4: Benefit Adjustment for RY1

Benefit Adjustment	RY1		
	System O&M	ID Electric	ID Natural Gas
Medical	$ (521,924)	$ (123,603)	$ (29,174)
Retirement	$ (30,492)	$ (7,221)	$ (1,704)
Total	$ (552,416)	$ (130,824)	$ (30,878)

The Company offers a comprehensive benefit plan for employees. Employees have several choices to elect benefits, such as medical and life insurance, so they can determine the best fit for their circumstances. The plans are designed to be competitive with the overall market practices and are in place to attract and retain qualified employees. Periodically, to aid in benchmarking, Avista participates in a comprehensive benefit evaluation study (BENEVAL) performed by an independent actuarial company, Willis Towers Watson. Similar to cash compensation, the Company generally targets the level of benefits it offers to be within +/- 15% of the market median.

Q. Please describe the Retirement portion of the Benefit Adjustment included in Adjustment 3.03 and Idaho's share of this expense.

A. The Company's Retirement portion of the calculation adjusts the 401(k) expense and Pension Plan from the 12ME June 30, 2022 test period to reflect what will be in

[22] Benefits associated with capital labor are embedded within the Company's Capital Adjustment.

effect during RY1, resulting in an overall system expense reduction of $30,000.[23] Estimates for Pension Plan expense is determined annually by Willis Towers Watson based on the expected return on assets, discount rates and asset value. The primary contributor to this decrease in expense is related to changes in asset value due to the actual return on assets for 2022, partially offset by changes in the discount rate and the expected long-term return on assets for 2023 prorated for the rate-effective period. Assumptions utilized in the calculation are presented to and approved by the Board of Directors annually.

In addition, these calculations and assumptions are reviewed by the Company's outside accounting firm annually for reasonableness and comparability to other Companies. The Company has included in this case the most recent estimates for 2023.[24] We anticipate updates for 2023 through 2025 to be available from our actuary sometime in the first quarter of 2023, and the Company will adjust pension expense at that time to reflect a prorated amount for RY1, 12ME August 31, 2024.

Further, the Company has made changes to the overall retirement plan, discussed below. The Company has proposed an increase consistent with proposed labor increases prorated for the rate effective period[25], as discussed in Pro Forma Labor Non-Exec Adjustment (3.01), resulting in an increase in 401(k) expense on a system basis of $733,000 for RY1.[26] Over the long term, we anticipate a decrease in pension expense will reduce overall retirement net expense.

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[23] See Pro Forma Employee Benefits Adjustment 24.08, which adjusts pro forma employee benefit amounts reflected in RY1, to reflect pro forma employee benefit amounts expected in RY2. The incremental overall system expense in RY2 for the Company's retirement portion is an increase of approximately $280,000.
[24] The estimate for 2023 was used as the basis for the rate effective period.
[25] See CONFIDENTIAL 3.01 & 24.04 Non-Executive Labor Adjustment workpaper, Pro-Forma Increases tab for detailed, annualized Union and Non-Union labor increases by year.
[26] See Pro Forma Employee Benefits Adjustment 24.08, which adjusts pro forma employee benefit amounts reflected in RY1, to reflect pro forma employee benefit amounts expected in RY2. The incremental increase in 401(k) expense on a system basis in RY2 is approximately $308,000.

Q. Please summarize changes to the Company's retirement plan in recent years.

A. In October 2013, the Company revised the defined benefit pension plan such that, as of January 1, 2014, the plan is closed to all non-union employees hired or rehired on or after January 1, 2014.[27] All actively employed non-union employees that were hired prior to January 1, 2014, and were covered under the defined benefit pension plan at that time, will continue accruing benefits as originally specified in the plan. In the 2022 Local 77 collective bargaining agreement, the Company and Local 77 bargaining unit have agreed to close the defined benefit pension plan to all Local 77 employees hired on or after January 1, 2024.[28] A defined contribution 401(k) plan replaced the defined benefit pension plan for all non-union and Local 659 bargaining unit employees hired or rehired on or after January 1, 2014 and Local 77 bargaining unit employees hired on or after January 1, 2024. Under the defined contribution plan, the Company will provide a non-elective contribution as a percentage of each employee's pay based on the age of the employee. This defined contribution is in addition to the existing 401(k) contribution where Avista matches a portion of the pay deferred by each participant. In addition to the above changes, the Company also revised our lump sum calculation for non-union retirees under the defined benefit pension plan to provide non-union participants who retire on or after January 1, 2014 with a lump sum amount equivalent to the present value of the annuity based upon applicable discount rates. Beginning January 1, 2024, this will also apply to Local 77. Likewise, those who were covered under the defined benefit pension plan previously, will

[27] Changes were applicable to Local Union 659 (Oregon operations) effective April 1, 2014.
[28] Changes were applicable to the Local 77B (DO/GC) bargaining unit (Distribution Operations and Gas Controllers) with their contract placement in 2017.

continue to accrue benefits as originally specified in the plan.

Q. Please now provide an overview of how medical expenses are determined by the Company.

A. Avista sponsors a self-funded medical plan that provides various levels of coverage for medical, dental and vision as a portion of employee benefits. Annually, medical premiums[29] for the Company are estimated by an independent consultant, Mercer,[30] based on medical trend, which is a combination of utilization (the pattern of use or intensity of services used for a particular timeframe), and the estimated increase in the costs (such as medical services, office visits, medical equipment, etc.) to treat patients from one year to the next. The following factors are taken into consideration in the development of premiums:

- Population Profile – the number and composition of participating employees (such as single person, family, age, etc.).
- Estimated Medical and Prescription Costs – the increase in unit cost for a given medical service or treatments, the mix and intensity of differing types of service, and new treatments/therapy/technology.
- Laws and Regulation – changes and associated costs, such as those required as part of the Affordable Care Act.

Actual medical expense will vary from premium cost estimates based on variations in plan utilization and actual components in the medical trend. For the past several years, actual expense had been lower than our premium cost estimates, resulting in lower costs for the Company and our customers. Some reasons include the effects of the Company's wellness programs, the severity of flu season in a given year, the level of acute or chronic illness, or for a variety of other reasons. However, due primarily to increased utilization

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[29] In this context, "premium" is defined as total medical costs including both the Company and employee contribution.

[30] Mercer is currently the world's largest human resources consulting firm, with more than 20,500 employees, based in more than 40 countries.

rates, price increases and our population profile, medical expenses have been trending upward.

As with the Pension Plan, estimates for the Post-Retirement Medical piece of the Medical adjustment are based on the expected return on assets, discount rates and asset value. In this case, the primary contributor to the change in expense is related to a change in cost trend assumptions. We anticipate updates for 2023 to be available sometime in the first quarter of 2023, and the Company will adjust expected medical expense, in this case, at that time. The net effect of the changes in medical costs on O&M expense described above, reflect a decrease in RY1 <u>system</u> expense of approximately $522,000.[31]

As shown in Table No. 4 above, the overall net impact of changes in pension and medical expense on a system basis for RY1 is a decrease of $552,000, or $131,000 Idaho electric and $31,000 Idaho natural gas.[32] Therefore, the Pro Forma Employee Benefits Adjustment (3.03) increases Idaho NOI by $103,000 for electric and $24,000 for natural gas. Again, the Company will update the level of expense as soon as possible during the process of the case, after receiving updated consultant information expected in early 2023.

Q. Please continue with your discussion of the RY1 pro forma adjustments.

A. The next adjustment is Electric Adjustment (3.04) and Natural Gas Adjustment (3.04) – **Pro Forma Information Services/Information Technology Costs**, which adjusts the actual level of IS/IT expense included in the 12ME June 30, 2022 test year to reflect expected expense increases in the twelve-month period September 1, 2023 through

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[31] See Pro Forma Employee Benefits Adjustment 24.08, which adjusts pro forma employee benefit amounts reflected in RY1, to reflect pro forma employee benefit amounts expected in RY2. The incremental increase in medical expense on a <u>system basis</u> in RY2 is approximately $856,000.

[32] See Pro Forma Employee Benefits Adjustment 24.08, which adjusts pro forma employee benefit amounts reflected in RY1, to reflect pro forma employee benefit amounts expected in RY2. Refer to Table No. 5 for the overall net impact of changes in pension and medical expense on a system basis for RY2.

August 31, 2024. This adjustment includes the incremental costs primarily associated with contractual agreements in place, pre-paid costs, or are the continuation of costs for products and services that have increased beyond the 12ME June 30, 2022 historical test period, associated with products and services, licensing and maintenance fees, and other costs for a range of information services programs. These incremental expenditures are necessary to support Company cyber and general security, emergency operations readiness, electric and natural gas facilities and operations support, and customer service. Mr. Kensok sponsors this adjustment and provides more information within his testimony. The effect of this adjustment decreases NOI by $322,000 for electric and by $73,000 for natural gas.

Electric Adjustment (3.05) and Natural Gas Adjustment (3.05) – **Pro Forma Property Tax**, restates the 12ME June 30, 2022 test period accrued levels of property taxes to the RY1 property tax expense levels, based on prorated property values as of December 31, 2022 (2023) and December 31, 2023 (2024) for the rate effective period (September 1, 2023 – August 31, 2024). The property tax balances include estimates for 2022-2024 and the Company will update with more current estimates through the process of the case. The net effect of this adjustment decreases NOI by $179,000 electric and $611,000 natural gas.[33]

Electric Adjustment (3.06) and Natural Gas Adjustment (3.06) – **Pro Forma Insurance Expense,** reflects increases from 12ME June 30, 2022 test period insurance expense for general liability, directors and officers ("D&O") liability, property and other (cyber, Colstrip and Worker's Comp) insurance to the level of insurance expense the Company is expecting during the Two-Year Rate Plan. Expected invoices for December

[33] See Pro Forma adjustment 24.03, which adjusts Pro Forma Property Tax Adjustment 3.05 amounts reflected in RY1, to include incremental 2024 and 2025 Property Tax expenses, on a pro rata basis, planned in RY2 above RY1 levels.

2022 for the Company's general and property insurance premiums, and estimated March 2023 for D&O insurance premiums were used to further estimate the planned insurance expense levels over the Two-Year Rate Plan. Company witness Ms. Andrews describes this adjustment, along with the Company's proposal of an insurance expense balancing account, in detail in her testimony. The Company will update any 2022 estimated amounts, as well as updated insurance expense levels expected over the Two-Year Rate Plan included in this case as soon as any actual invoices in 2022/2023 are available. The effect of this adjustment decreases NOI by $972,000 for electric and by $112,000 for natural gas.

Electric Adjustment (3.07) and Natural Gas Adjustment (3.07) – **Pro Forma EDIT (RSGM),** adjusts the electric and natural gas excess deferred income taxes (EDIT) amortization expense included in the 12ME June 30, 2022 test period to reflect the level of EDIT amortization expense expected for the rate effective period. As discussed by Ms. Andrews, in 2017, the Tax Cuts and Jobs Act (TCJA) was enacted changing the corporate tax rate from 35% to 21%. As a result of the TCJA, the Company remeasured its deferred tax assets and liabilities to the new tax rate, resulting in the creation of EDIT on the 14% rate differential. The Company started to reverse the plant EDIT balance using the Average Rate Assumption Method (ARAM) through December 31, 2021. Beginning January 1, 2022, the Company switched its method of amortizing EDIT from ARAM to the Reverse South Georgia Method (RSGM). The Company's filed revenue requirement in this case utilizes the RSGM for both rate years. Ms. Andrews sponsors this adjustment and discusses the change from ARAM to RSGM in her testimony. The effect of this adjustment decreases electric NOI by $200,000 and natural gas NOI by $43,000.

Electric Adjustment (3.08) and Natural Gas Adjustment (3.08) – **Pro Forma Capital Additions 12.2022 EOP**, which reflects July 1, 2022 through December 31, 2022 capital additions[34] together with the associated A/D and ADFIT at a December 31, 2022 EOP basis. This adjustment also includes associated depreciation expense for these additions, as well as, incremental depreciation expense on plant-in-service at June 30, 2022. In addition, the plant-in-service at June 30, 2022 EOP was adjusted to a December 31, 2022 EOP basis. Finally, retirements for the six months ended December 31, 2022 on plant-in-service at June 30, 2022 were pro formed reducing depreciation expense, which was included in the overall impact of this adjustment. Ms. Benjamin sponsors and describes this adjustment in detail within her testimony. The effect of this adjustment increases Idaho rate base $38,139,000 electric and $5,123,000 natural gas. The effect of this adjustment on Idaho NOI is a decrease of $1,092,000 electric and $135,000 natural gas.

Electric Adjustment (3.09) and Natural Gas Adjustment (3.09) – **Pro Forma Capital Additions 08.2023 EOP**, reflects January 1, 2023 through August 31, 2023 capital additions together with the associated A/D and ADFIT at an August 31, 2023 EOP basis. This adjustment also includes associated depreciation expense for these additions, as well as, incremental annualized depreciation expense on plant-in-service at December 31, 2022. In addition, the plant-in-service at December 31, 2022 EOP was adjusted to an August 31, 2023 EOP basis. Finally, retirements for the eight months-ended August 31, 2023 on plant-in-service at December 31, 2022 were pro formed reducing depreciation expense, which was included in the overall impact of this adjustment. Ms. Benjamin sponsors and describes this adjustment in detail within her testimony. The effect of this adjustment increases Idaho rate

[34] For the period July 1, 2022 through August 31, 2025, capital additions associated with connecting new customers to the Company's system (New Revenue – Growth Business Case) were included. An increase in revenues from growth in the number of customers from the historical test year to the RY1 and RY2 rate periods are included, therefore, the growth in plant investment associated with customer growth was also included.

base $7,859,000 electric and $1,818,000 natural gas. The effect of this adjustment on Idaho NOI is a decrease of $2,494,000 electric and $163,000 natural gas.

Q. Please now turn to page 9 of Schedule 1 (electric) and Schedule 2 (natural gas) of Exhibit No. 4, and discuss the pro forma adjustments shown.

A. Beginning on page 9 of Schedule 1 (electric) and Schedule 2 (natural gas) of Exhibit No. 4 are Electric Adjustment (3.10) and Natural Gas Adjustment (3.10) – **Depreciation Study**. Periodically the Company completes a depreciation study and requests modifications to its depreciation rates. As discussed by Ms. Benjamin, the Company will file on or before February 22, 2023 applications with the Commission requesting authority to revise its Idaho electric and natural gas book depreciation rates for both common/allocated plant and direct Idaho plant, effective September 1, 2023. The Company will file similar applications in Washington and Oregon at this time as well. This adjustment captures the effect of updating Idaho electric and natural gas depreciation rates effective September 1, 2023 on plant-in-service at August 31, 2023 on an AMA basis. The impact of changing depreciation rates for plant-in-service at August 31, 2023 on an EOP basis and all additions after September 1, 2023 are built into the other capital adjustments (3.11, 24.01-24.02). Ms. Benjamin discusses this adjustment in detail within her testimony and Mr. Spanos sponsors the Depreciation Study in his testimony. The effect of this adjustment decreases depreciation expense by $1,524,000 for electric and $324,000 for natural gas, resulting in an increase to Idaho electric and natural gas NOI of $1,204,000 and $256,000, respectively.

Electric Adjustment (3.11) and Natural Gas Adjustment (3.11) – **Pro Forma Capital Additions 08.2024 AMA**, reflects September 1, 2023 through August 31, 2024 capital additions together with the associated A/D and ADFIT at an August 31, 2024 AMA basis. This adjustment also includes associated depreciation expense for these additions. In addition, the plant-in-service at August 31, 2023 EOP was adjusted to an August 31, 2024 AMA basis. Finally, retirements for the twelve months-ended August 31, 2024 on an AMA basis on plant-in-service at August 31, 2023, were pro formed reducing depreciation expense, which was included in the overall impact of this adjustment. Ms. Benjamin sponsors and describes this adjustment in detail within her testimony. The effect of this adjustment increases Idaho rate base $17,554,000 electric and $2,978,000 natural gas. The effect of this adjustment on Idaho NOI is a decrease of $2,586,000 electric and $434,000 natural gas.[35]

Electric Adjustment (3.12) and Natural Gas Adjustment (3.12) – **Pro Forma Revenue and Operation & Maintenance (O&M) Offsets,** includes pro formed offsetting revenue associated with growth capital and O&M offsets related to specific plant additions, which were reviewed for any net O&M offsets that are expected in RY1. Specific savings identified were included as a reduction to O&M expenses and were discussed in the direct testimonies of Company witnesses Mr. DiLuciano, Mr. Kinney, and Mr. Kensok, with the capital asset with which the net offset relates. The net effect of this adjustment increases NOI for electric by $2,751,000 and for natural gas by $1,201,000. As noted above, additional reductions in expense were reflected in Pro Forma Adjustments (3.08) through (3.11) (as well as pro forma adjustments (24.01) and (24.02)) with the inclusion of retirements in each electric and natural gas pro forma capital adjustment.

Electric Adjustment (3.13) and Natural Gas Adjustment (3.13) – **Pro Forma Fee-Free Amortization,** adjusts the electric and natural gas test period "fee-free" expense and

[35] For pro forma capital additions included beyond RY1, refer to Pro Forma Capital Additions Adjustments (24.01) and (24.02) described below.

amortization expense, to reflect the appropriate RY1 approved expense levels.[36] In Case No. AVU-E-21-01, the Commission approved a three-year amortization period, beginning September 1, 2021, for the remaining deferred electric balance of $291,000 ($97,000 annually). Therefore, for electric, this adjustment reflects an annual Fee-Free expense of $510,000 and deferred amortization expense of $97,000 as approved by the Commission. The deferred balance will be fully amortized by August 31, 2024, and is therefore removed in RY2 (see RY2 electric Adjustment 24.05 – Pro Forma Fee Free Amortization).

For natural gas, in Case No. AVU-G-21-01, the Commission approved a three-year amortization period, beginning September 1, 2021, for the deferred natural gas balance of $475,000 (approximately $158,000 annually). Therefore, for natural gas, this adjustment reflects an annual Fee-Free expense of $335,000 and deferred amortization expense of $158,000 as approved by the Commission. The deferred balance will be fully amortized by August 31, 2024. Thus, the amortization expense of approximately $158,000 is removed in RY2 (see RY2 natural gas Adjustment 24.05 – Pro Forma Fee Free Amortization). The net effect of adjusting test period expense to RY1 levels as described above, decreases electric NOI by $3,000 and natural gas NOI by $35,000.

Electric Adjustment (3.14) and Natural Gas Adjustment (3.14) – **Pro Forma Regulatory Amortizations** reflects the proposal of amortizing several existing regulatory

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[36] On April 1, 2016 the Commission issued Order No. 33494 in Case No. AVU-E-16-01 and AVU-G-16-01 approving Avista's application for an order authorizing accounting and ratemaking treatment of fees for credit and debit card payments made by residential customers (residential fee-free payment program). The Commission ordered the amortization period was to be determined in the Company's next general rate case. The fee-free payment program was then successfully launched February 19, 2017.
As of November 30, 2019, for electric, and January 31, 2020, for natural gas, $678,000 and $475,000, respectively, of Idaho customer transactions through the fee-free payment program were deferred, for an Idaho total of $1,153,000. With the conclusion of the electric general rate case (Docket AVU-E-19-04), the Company received approval to begin amortizing the electric deferred balance over three years beginning January 1, 2020.

assets and liabilities – amounts either deferred and not yet amortized, or residual balances of previous amortizations, over a two-year period beginning September 1, 2023. A brief description of the regulatory assets and liabilities included in this adjustment are as follows:

Avista Case No. AVU-E-20-01 (Order No. 34606 dated March 23, 2020) allowed the Company to defer, with no carrying charge, its Idaho jurisdictional incremental O&M costs associated with joining the California Independent System Operator's (CAISO) Western Energy Imbalance Market (EIM) until the go-live date. This adjustment proposes the approximately $699,000 of Idaho electric deferred costs, as of June 30, 2022, recorded in FERC Account 182334 – Regulatory Asset EIM be included in base rates and amortized for recovery over two years beginning September 1, 2023.

In Case No. AVU-E-20-05, Avista was authorized in Order No. 34883, dated December 31, 2020, to defer incremental O&M expenses and monthly depreciation expense associated with the Wildfire Plan investment into FERC Account 182.3 (Other Regulatory Assets) and that no carrying charge apply. This adjustment proposes the Idaho electric deferred costs as of June 30, 2022 (for the period July 1, 2020 through August 31, 2021), totaling approximately $2.5 million, recorded in FERC Account 182344 – Regulatory Asset – Wildfire Resiliency, be included in base rates and amortized for recovery over two years beginning September 1, 2023.

In the Company's last general rate case, Case No. AVU-E-21-01, the Commission approved in Order No. 35156 a two-way Wildfire O&M Expense Balancing Account to defer the difference in actual O&M Wildfire expenses, up or down, from the authorized "base" level.[37] This adjustment proposes the Idaho <u>electric</u> deferred costs from September 1, 2021 through September 30, 2022, totaling approximately $5.7 million, recorded in FERC Account 182353 – Regulatory Asset – Wildfire Balancing, be included in base rates and amortized for <u>recovery</u> over two years beginning September 1, 2023. The deferred balance will continue to accrue additional wildfire expense deferrals over time.

Per Case No. GNR-U-20-03 (including consolidated Case Nos. AVU-E-20-03; AVU-G-20-03; FLS-W-20-02; GSW-W-20-01; IPC-E-20-19; and PAC-E-20-04), the Commission granted Avista authority in Order No. 34718, dated July 8, 2020, to account for unanticipated, emergency-related expenses due to the COVID-19 public health emergency as regulatory assets for possible recovery through future rates. The Commission further ordered that the utilities must analyze the CARES Act NOL provision and apply any benefit to offsetting the deferral account created for emergency-related expenses. Additional benefits, such as reduced employee travel and training, etc. were to also be accounted for, reducing COVID-19 related expense. This adjustment proposes the Idaho <u>net</u> deferred costs in FERC Account 182347 – Regulatory Asset COVID-19 ($551,000 electric, $238,000 natural gas) and FERC Account 254347 – Regulatory Liability – COVID-19 Deferral ($2,632,000 electric, $266,000 natural gas), as of June 30, 2022, totaling a net liability owed customers, of approximately $2.1 million for <u>electric</u> and $28,000 for <u>natural gas</u>, be included in base rates and amortized for <u>rebate</u> to customers over two years beginning September 1, 2023.

As a part of the Settlement Stipulation approved by the Commission in the

[37] Per Order No. 35156, p. 5, the authorized "base" level approved in Rate Year 1, beginning September 1, 2021 through August 31, 2022, was $1.471 million and in Rate Year 2, beginning September 1, 2022 through August 31, 2023, was $1.836 million.

Company's 2015 general rate case, Case No. AVU-E-15-05 (Order No. 33437 dated December 18, 2015), the Company was ordered to rebate $5.6 million in 2014 electric revenue sharing to customers through electric Schedule 97, or approximately $2.8 million annually through December 31, 2017. This rebate was first approved in the Company's 2012 general rate case, Case No. AVU-E-12-08 (Order No. 32769 dated March 17, 2013)[38] and was extended through December 31, 2015 as part of Case No. AVU-E-14-05.[39] This adjustment proposes to refund the residual Idaho electric balance in FERC Account 254229 – Idaho Earnings Test Deferral remaining of approximately $687,000 as of June 30, 2022, be included in rates and amortized for rebate to customers over two years beginning September 1, 2023.

In Case No. AVU-E-18-03, Avista was authorized in Order No. 34276, dated March 19, 2019, beginning April 1, 2019 to use Tariff Schedule 74 to return to customers $5.766 million in temporary tax benefits the Company received under the federal Tax Cuts and Jobs Act of 2017 (TCJA) from January 1 – May 1, 2018. This adjustment proposes to return the residual Idaho electric balance in FERC Account 254230 – Tax Reform Amortization, estimated to be approximately $130,000 (including interest) through August 31, 2023, to be included in rates and amortized for rebate to customers over two years beginning September 1, 2023. Refer to my workpapers related to the Pro Forma Regulatory Amortizations Adjustment (3.14) for more information, including a schedule of interest accrued and the estimated balance at August 31, 2023.[40]

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[38] In the Company's 2012 general rate case, Case No. AVU-E-12-08 (Order No. 32769 dated March 17, 2013), the Commission ordered Avista to refund to customers one-half of any earnings above the 9.8% return on equity for each of the years 2013 and 2014.

[39] Stipulation and Settlement – AVU-E-15-05 & AVU-G-15-01, p. 14, paragraph 16. Electric Rebate Extension.

[40] See workpaper tab Acct 254230.

As part of Case No. AVU-G-21-03 (Order No. 35150 dated August 30, 2021), the Commission authorized the Company to refund to customers through Schedule 178 deferred credit balances associated with Allowance for Funds Used During Construction (AFUDC)[41], as well as depreciation expense and the CARES Act benefits, effective September 1, 2021. This adjustment proposes the residual over-amortized Idaho natural gas balance in FERC Account 254319 – Regulatory Liability AFUDC Equity Tax Deferral, of approximately $60,000 as of September 30, 2022, be included in rates and amortized for recovery from customers over two years beginning September 1, 2023.

For additional detail on the proposed amortizations included, please refer to my workpapers related to the Pro Forma Regulatory Amortizations Adjustment (3.14). The net effect of this adjustment is an increase in expense of $3.0 million for electric and $16,000 for natural gas, annually over the Two-Year Rate Plan, resulting in a decrease in NOI of $2,376,000 for electric and $13,000 for natural gas.

Electric Adjustment (3.15) and Natural Gas Adjustment (3.15) – **Pro Forma Misc. O&M Expense**, as discussed and sponsored by Ms. Andrews, reflects escalated increases in certain Company O&M and A&G expenses, from the 12ME June 30, 2022 test year through RY1, effective September 1, 2023, through August 31, 2024, not otherwise pro formed within the Company's electric or natural gas Pro Forma Studies. An annual escalation rate of 7.22% for electric and natural gas operations was applied by FERC account to certain O&M and A&G annual test period balances as of June 30, 2022, through August 31, 2024 (or 2.17 years). All 12ME June 30, 2022 test period expenses restated or pro formed within the electric or natural gas Pro Forma Studies, are excluded prior to the use of the escalation,

[41] In a prior Avista case, Case No. AVU-G-19-01 (Order No. 34326 dated May 2, 2019), the Commission approved the Company's application for accounting and ratemaking treatment related to its AFUDC.

including the following expenses: 1) all labor and benefits, including, salaries, incentives, pension and medical costs; 2) insurance expenses and amortizations; 3) IS/IT expenses; 4) power supply costs; 5) Montana riverbed lease expenses; 6) Colstrip and CS2 major maintenance expenses; 7) wildfire-related expenses, 8) administrative expenses (office space charges); and 9) other expenses removed through restating adjustments (i.e., miscellaneous restating, eliminate adder schedule balances, gas supply costs, and revenue-related expenses). The effect of this adjustment decreases RY1 Idaho electric NOI by $3,353,000 and natural gas NOI by $672,000.

Electric Adjustment (3.16) – **Pro Forma Wildfire Plan Expenses** reflects the net increase in expenses associated with the Company's Wildfire Resiliency Plan ("Wildfire Plan"), as supported by Mr. Howell.[42] This pro forma adjustment reduces 12ME June 30, 2022 test period distribution and transmission operating expenses by $1,858,000 to reflect Idaho's share of annual wildfire operating expenses expected during the Two-Year Rate Plan of $4,637,000. This adjustment also removes non-recurring test period deferred regulatory credit expense from the test period (removes FERC Account 407 balances), related to deferring wildfire expenses during the period July 1, 2021 through June 30, 2022, increasing A&G Regulatory Amortization expense by $5,272,000. The net of this adjustment increases related wildfire expense by $3,414,000 above test period levels, prior to the impact of the amortization of the Deferred Wildfire balances, or depreciation expense

[42] Wildfire Plan capital additions, together with associated A/D, ADFIT, and depreciation expense, from July 1, 2022 through August 31, 2025 over the Two-Year Rate Plan are included in Pro Forma Capital Additions Adjustments 3.08 through 3.11 in RY1, and Pro Forma Capital Additions Adjustments 24.01 and 24.02 in RY2, sponsored by Ms. Benjamin. Mr. Howell discusses the need for these additions in his direct filed testimony.

related to pro formed Wildfire Plan capital additions.[43] Ms. Andrews discusses this adjustment, as well as the Wildfire Recovery and Balancing Account, in detail within her testimony. The effect of this adjustment decreases Idaho electric NOI by $2,697,000.

The final RY1 adjustment is Electric Adjustment (3.17) – **Pro Forma Colstrip Capital Add & Amortization**, as discussed and sponsored by Ms. Andrews, reflects the approved treatment by the IPUC to recover Avista's investment in the Colstrip Units 3 and 4 generating facilities after reflecting an accelerated depreciation rate of 2027.[44] This adjustment also reflects the Company's proposal to include the Colstrip capital additions between July 1, 2022 through December 31, 2022 in the Colstrip Regulatory Asset for recovery over its authorized amortization period. Mr. Kinney sponsors the Colstrip capital additions testimony, describing the capital that has been included in this general rate case, including capital additions between July 1, 2022, and December 31, 2022, for prudency review in this proceeding. The effect of this adjustment decreases Idaho regulatory amortization expense by $155,000, increases electric NOI by $135,000 and increases Idaho electric rate base by $2,450,000.[45]

RY2 (09.2024 – 08.2025) – Summary of Adjustments

Q. Please now explain each of the RY2 Pro Forma adjustments included in Exhibit No. 4, starting on page 10 of Schedule 1 and Schedule 2.

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[43] See Adjustment 3.14 – Pro Forma Regulatory Amortizations, which includes the proposed two-year amortization of Wildfire related deferred Regulatory Assets: 1) "Regulatory Credit - Wild Fire Resiliency" balance of $2.54 million, resulting from wildfire expenses deferred from July 1, 2021 – August 31, 2021, and 2) "Regulatory Credit - Wildfire Balancing Account O&M" balance of $5.67 million, resulting from wildfire expenses deferred from September 1, 2021 – September 30, 2022. The annual amortization of these two balances over the Two-Year Rate Plan total $4.12 million.

[44] Avista owns a 15% share of two coal-fired generation facilities located in Colstrip, Montana, known as Colstrip Units 3 and 4, which have a combined capacity of about 1,480 MW. These two facilities were placed in service in 1984 and 1986.

[45] As discussed by Ms. Andrews, the Company inadvertently did not add the pro forma capital addition into the amortization. This understated the amortization expense by $80,770. This will be adjusted during the process of the case.

A. For RY2, the Company has included the incremental expenses above RY1 level expenses for the following major cost categories: 1) power supply and transmission revenues/expenses, 2) new plant investment, including depreciation, through August 31, 2025 on an AMA basis[46] and 3) property taxes on investment through 2024; as well as updates to certain O&M and A&G expenses, such as: 4) non-executive labor increases; 5) Colstrip/CS2 maintenance amortization expense; 6) employee benefits; and 7) miscellaneous O&M expense. The Company has also included the impact of 8) eliminating the fee free amortization in RY2, and 9) offsetting revenue associated with growth capital and O&M offsets related to specific plant additions. The Company has provided workpapers, in electronic format, outlining additional details related to each of the RY2 pro forma adjustments. A summary of each adjustment follows:

The first adjustment, starting on Exhibit No. 4, page 10 of Schedule 1 and Schedule 2, is Electric Adjustment (24.00P) – **Pro Forma Power Supply**. Similar to Electric Adjustment (3.00P) - **Pro Forma Power Supply** discussed previously in my testimony, this adjustment was made under the direction of Mr. Kalich and is explained in detail in his testimony. This adjustment includes pro forma power supply-related revenues and expenses to reflect the twelve-month period September 1, 2024 through August 31, 2025, using weather-normalized historical loads. Mr. Kalich's testimony outlines the system level of pro forma power supply revenues and expenses that are included in this adjustment. The adjustment in column (24.00P) represents the Idaho jurisdictional share of those amounts. The net effect of this adjustment decreases electric NOI by $3,596,000.[47]

[46] The Company has not included Colstrip Unit 3 and 4 additions beyond 2022 investments and the effect on regulatory amortization in RY2 in this case.
[47] See Pro Forma Adjustment 3.00P, which adjusts pro forma power supply amounts reflected in the 12ME June 30, 2022 test period, to reflect pro forma power supply amounts expected in RY1.

Electric Adjustment (24.00T) – **Pro Forma Transmission Revenue/Expense**, was made under the direction of Mr. Dillon and is explained in detail in his testimony. This adjustment includes pro forma transmission-related revenues and expenses to reflect the twelve-month period September 1, 2024 through August 31, 2025. The net effect of this adjustment decreases electric NOI by $265,000.[48]

Electric Adjustment (24.01) and Natural Gas Adjustment (24.01) - **Pro Forma Capital Additions 08.2024 EOP**, reflects September 1, 2023 through August 31, 2024 capital additions[49] together with the associated A/D and ADFIT at an August 31, 2024 EOP basis. In addition, the plant-in-service at August 31, 2024 AMA was adjusted to an August 31, 2024 EOP basis. Since this adjustment is only pro forming the change from August 31, 2024 from an AMA to EOP basis, there is no impact to depreciation expense for the capital additions and retirements because the impact was recorded in Adj. 3.11 – Planned Capital Additions 08.2024 AMA. The impact of changing from AMA to EOP of depreciation expense on additions and retirements for the 12ME August 31, 2024 is picked up in the subsequent adjustment, Adj. 24.02 – Capital Additions 08.2025 AMA, described below. Ms. Benjamin sponsors and describes this adjustment in detail within her testimony. The net impact of this adjustment is an increase in total rate base of $9,876,000 electric and $1,627,000 natural gas. The net effect of this adjustment on NOI is an increase of $51,000 electric and $8,000 natural gas.

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[48] See Pro Forma Adjustment 3.00T, which adjusts pro forma transmission-related revenues and expenses reflected in the 12ME June 30, 2022 test period, to reflect pro forma transmission-related revenue/expense amounts expected in RY1.

[49] As noted previously, for the period July 1, 2022 through August 31, 2025, capital additions associated with connecting new customers to the Company’s system (New Revenue – Growth Business Case) were included. An increase in revenues from growth in the number of customers from the historical test year to the RY1 and RY2 rate periods are included, therefore, the growth in plant investment associated with customer growth was also included.

Electric Adjustment (24.02) and Natural Gas Adjustment (24.02) **Capital Additions 08.2025 AMA** reflects September 1, 2024 through August 31, 2025 capital additions[50] together with the associated A/D and ADFIT at an August 31, 2025 AMA basis. This adjustment also includes associated depreciation expense for these additions. In addition, the plant-in-service at August 31, 2024 EOP was adjusted to an August 31, 2025 AMA basis. Finally, retirements for the twelve months-ended August 31, 2025 on an AMA basis on plant-in-service at August 31, 2024, were pro formed reducing depreciation expense, which was included in the overall impact of this adjustment. Ms. Benjamin sponsors and describes this adjustment in detail within her testimony. The net impact of this adjustment is an increase in total rate base of $24,983,000 for electric and $2,977,000 for natural gas. The net effect of this adjustment on NOI is a decrease of $2,124,000 for electric and an increase of $33,000 for natural gas.

Electric Adjustment (24.03) and Natural Gas Adjustment (24.03) – **Pro Forma Property Tax**, which reflects incremental property tax expense from RY1 levels (included in Pro Forma Property Tax adjustment (3.05) to RY2 levels, based on prorated property values as of December 31, 2023 (2024) and December 31, 2024 (2025) for the rate effective period (September 1, 2024 – August 31, 2025). The property tax balances include estimates for 2022-2024 and the Company will update with more current estimates through the process of the case. The net effect of this adjustment decreases electric NOI by $556,000 and increases natural gas NOI by $14,000.

Electric Adjustment (24.04) and Natural Gas Adjustment (24.04) – **Pro Forma Labor Non-Exec**, reflects incremental union and non-union wages and salaries from RY1 (included in Pro Forma Labor Non-Exec adjustment (3.01)) to RY2 (excludes executive

[50] *Ibid.*

salaries). For <u>non-union</u> and <u>union</u> employees, wages and salaries were adjusted to annualize (add 4 months) the estimated increase for 2024 effective March 1, 2024, for non-union employees, and March 26, 2024, for union employees, and a prorated amount (6 months non-union, 5 months union) of the estimated increase for 2025 effective March 1, 2025, for non-union employees, and March 26, 2025, for union employees.[51] The net effect of this adjustment on NOI is a decrease of $865,000 electric and $193,000 natural gas.

Electric Adjustment (24.05) and Natural Gas Adjustment (24.05) – **Pro Forma Fee Free Amortization**, leaves the annual electric and natural gas expense associated with the "fee-free" payment expense at the level expected during RY1 and removes the amortization expense of the "fee free" payments approved for deferral, as the deferred balance is fully amortized as of August 31, 2024, as described in Pro Forma Fee-Free Amortization Adjustment (3.13). Thus, the amortization expense of $97,000 for electric, and approximately $158,000 for natural gas are eliminated in this adjustment. The net effect of this adjustment increases RY2 Idaho NOI by $77,000 for electric and $125,000 for natural gas.

Electric Adjustment (24.06) and Natural Gas Adjustment (24.06) – **Pro Forma Revenue and O&M Offsets**, includes incremental pro formed offsetting revenue associated with growth capital in RY2, and O&M offsets related to specific plant additions, which were reviewed for any net O&M offsets that are expected in RY2, beyond RY1 levels. Specific incremental savings identified were included as a reduction to O&M costs and were discussed in the direct testimonies of witnesses Mr. DiLuciano, Mr. Kinney, and Mr. Kensok, with the capital asset with which the net offset relates. The net effect of this

[51] See CONFIDENTIAL 3.01 & 24.04 Non-Executive Labor Adjustment, Pro-Forma Increases tab for detailed, annualized Union and Non-Union labor increases by year.

adjustment increases RY2 Idaho NOI by $1,526,000 for electric and by $628,000 for natural gas.

Electric Adjustment (24.07) and Natural Gas Adjustment (24.07) – **Pro Forma Miscellaneous O&M Expense**, as discussed and sponsored by Ms. Andrews, reflects escalated increases in certain Company O&M and A&G expenses, to reflect <u>incremental</u> expenses in RY2, beyond RY1 levels, effective September 1, 2024, through August 31, 2025, not otherwise pro formed within the Company's electric or natural gas Pro Forma Studies. The same escalation growth rate used in RY1, applied by FERC account to certain O&M and A&G annual balances as of RY1, is used to escalate RY2 above RY1 levels, of 7.22% for electric and natural gas operations. This adjustment decreases RY2 Idaho NOI by $1,545,000 for electric and $310,000 for natural gas.

Q. Please continue with your explanation of the remaining RY2 pro forma adjustments included on page 11 of Schedule 1 and Schedule 2 of Exhibit No. 4.

A. The next adjustments on page 11 of Schedule 1 and Schedule 2 of Exhibit No. 4 include Electric Adjustment (24.08) and final RY2 Natural Gas Adjustment (24.08) – **Pro Forma Employee Benefits**, adjusts Retirement Plans (401(k) and Pension), and medical insurance for active employees and for those retired (post-retirement medical) to reflect <u>incremental</u> expenses in RY2, beyond RY1 levels (see Pro Forma Employee Benefits Adjustment (3.03)), effective September 1, 2024, through August 31, 2025. Annually, the Company works with independent consultants in order to determine the appropriate level of expense for both the Retirement Plans (Willis Towers Watson) and the Medical Plans (Mercer). The impact of these changes to RY2 are summarized in Table No. 5 below:[52]

[52] Benefits associated with capital labor are embedded within the Company's Capital Adjustment.

<u>Table No. 5: Benefit Adjustment for RY2</u>

Benefit Adjustment			RY2			
		System O&M		**ID Electric**		**ID Natural Gas**
Medical	$	856,379	$	202,809	$	47,868
Retirement		279,609		66,217		15,629
Total	$	1,135,988	$	269,026	$	63,497

The net effect of this adjustment decreases RY2 Idaho NOI by $213,000 for electric and $50,000 for natural gas.

The final RY2 electric adjustment, Electric Adjustment (24.09) – **Pro Forma Colstrip/CS2 Maintenance,** adjusts the Colstrip/CS2 Maintenance expense level included in RY1 (see restating Colstrip/CS2 Maintenance Adjustment (2.12)) to reflect the revised expense for RY2. This adjustment adjusts expense to a pro rata share of years 2024 and 2025, which include one-third of each amount deferred (actual or estimated) for calendar years 2021 through 2023 and 2022 through 2024, respectively, increasing Idaho electric expense by approximately $246,000, and decreasing NOI by $194,000. [53]

<u>RY1 and RY2 Final Summary</u>

Q. How much additional net operating income would be required for the State of Idaho electric operations to allow the Company an opportunity to earn its proposed 7.59% rate of return on a pro forma basis for the Two-Year Rate Plan?

A. For electric, the net operating income deficiency amounts to $29,483,000 for RY1 and $10,350,000 (incremental) for RY2, as shown on line 5, page 3 of Exhibit No. 4,

[53] See Restating Colstrip/CS2 Maintenance Adjustment 2.12, which adjusts Colstrip/CS2 maintenance amounts reflected in 12ME June 30, 2022 test year, to reflect the pro rata share of years 2023 and 2024, which include one-third of each amount deferred (actual or estimated) for calendar years 2020 through 2022 and 2021 through 2023, respectively, to reflect Colstrip/CS2 maintenance amounts expected in RY1.

Schedule 1. The resulting revenue requirement is shown on line 7 and amounts to $37,462,000 for RY1, or a base increase of 13.6% (14.7% billed), and $13,150,000 (incremental) for RY2, or a base increase of 4.2% (4.5% billed).

Q. How much additional net operating income would be required for the State of Idaho natural gas operations to allow the Company an opportunity to earn its proposed 7.59% rate of return on a pro forma basis for the Two-Year Rate Plan?

A. For natural gas, the net operating income deficiency amounts to $2,180,000 for RY1 and $93,000 (incremental) for RY2, as shown on line 5, page 3 of Exhibit No. 4, Schedule 2. The resulting revenue requirement is shown on line 7 and amounts to $2,771,000 for RY1, or a base increase of 6.0% (2.7% billed), and $120,000 (incremental) for RY2, or a base increase of 0.3% (0.1% billed).

VI. ALLOCATION PROCEDURES

Q. Have there been any changes to the Company's system and jurisdictional procedures since the Company's last general electric and natural gas cases, Case Nos. AVU-E-21-01 and AVU-G-21-01, respectively?

A. No. For ratemaking purposes, the Company allocates revenues, expenses and rate base between electric and natural gas services and between Idaho, Washington and Oregon jurisdictions where electric and/or natural gas service is provided. The annually updated allocation factors used in this case have been provided with my workpapers.

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

A. Yes, it does.