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IDAHO PUBLIC
UTILITIES COMMISSION

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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION	)	CASE NO. AVU-E-25-01
OF AVISTA CORPORATION FOR THE	)	CASE NO. AVU-G-25-01
AUTHORITY TO INCREASE ITS RATES	)	
AND CHARGES FOR ELECTRIC AND	)	
NATURAL GAS SERVICE TO ELECTRIC	)	DIRECT TESTIMONY
AND NATURAL GAS CUSTOMERS IN THE	)	OF
STATE OF IDAHO	)	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, leading the Company’s natural gas general rate case filing in Oregon, 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, 2025 through August 31, 2027. 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, 2024 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, 2025 through August 31, 2026 (here after "RY1") and Rate Year 2, September 1, 2026 through August 31, 2027 (here after "RY2"). 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.

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 RY1 electric base rate relief of $42.951 million, or 14.0% (14.4% on a billed basis), effective September 1, 2025. The Company is also requesting RY2 electric base rate relief of $17.674 million or 5.0% (5.2% on a billed basis), effective September 1, 2026.

- The Company is requesting a Two-Year Rate Plan with RY1 natural gas base rate relief of $8.803 million, or 17.7% (10.3% on a billed basis), effective September 1, 2025. The Company is requesting RY2 natural gas base rate relief of $983,000 or 1.7% (1.0% on a billed basis), effective September 1, 2026.

- The Company has pro formed in this case capital additions for the period July 1, 2024 through August 31, 2027. These capital additions, along with changes in power supply, are the primary drivers of the Company's request for rate relief.

II. COMBINED REVENUE REQUIREMENT SUMMARY – TWO-YEAR RATE PLAN: SEPTEMBER 1, 2025 THROUGH AUGUST 31, 2027

Q. Please describe the Company's Two-Year Rate Plan proposed for the period September 1, 2025, through August 31, 2027.

A. The Company is proposing a Two-Year Rate Plan in Idaho from September 1, 2025, to August 31, 2027, for both electric and natural gas. This includes rate increases for RY1, effective September 1, 2025, and RY2, effective September 1, 2026. The proposed Two-Year Rate Plan aims to avoid annual rate cases in Idaho, benefiting all stakeholders by providing rate certainty for customers, reducing administrative burdens and litigation costs for all parties, and giving Avista a two-year period to manage its business to have an opportunity to achieve a fair rate of return.[1]

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

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.

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[1] 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. After considering all standard Commission basis and restating 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 4.87% and 4.76%, respectively for RY1, ending August 31, 2026. After considering additional incremental pro forma adjustments for RY2, ending August 31, 2027, the pro forma electric and natural gas ROR are 3.94% and 4.52%, respectively. These return levels are well below the Company's requested rate of return of 7.68%.[2] Table No. 1 below provides a summary of the RY1 and RY2 ROR per the pro forma studies versus that proposed by the Company.

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	4.87%	3.94%	7.68%
Idaho Natural Gas	4.76%	4.52%	7.68%

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, 2024; (2) RY1 12ME August 31, 2026; (3) RY2 12ME August 31, 2027; and (4) requested.

[2] Current authorized ROR for both Idaho electric and natural gas is 7.19%.

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

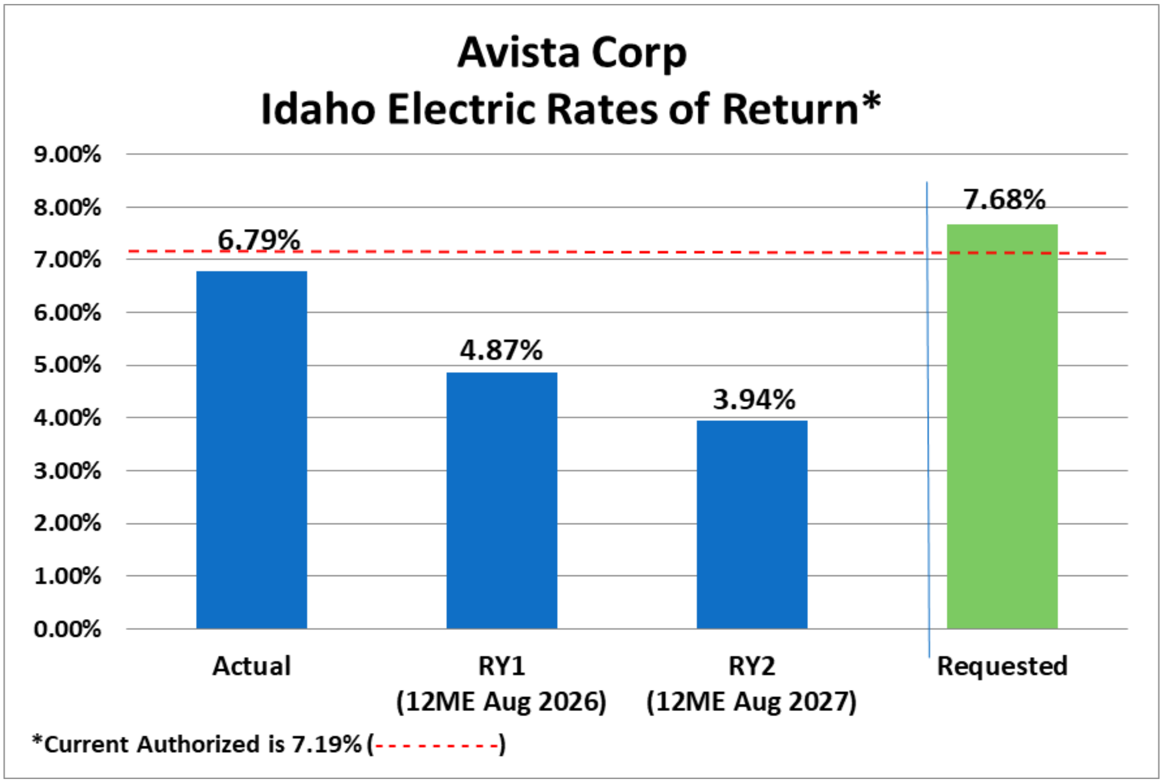
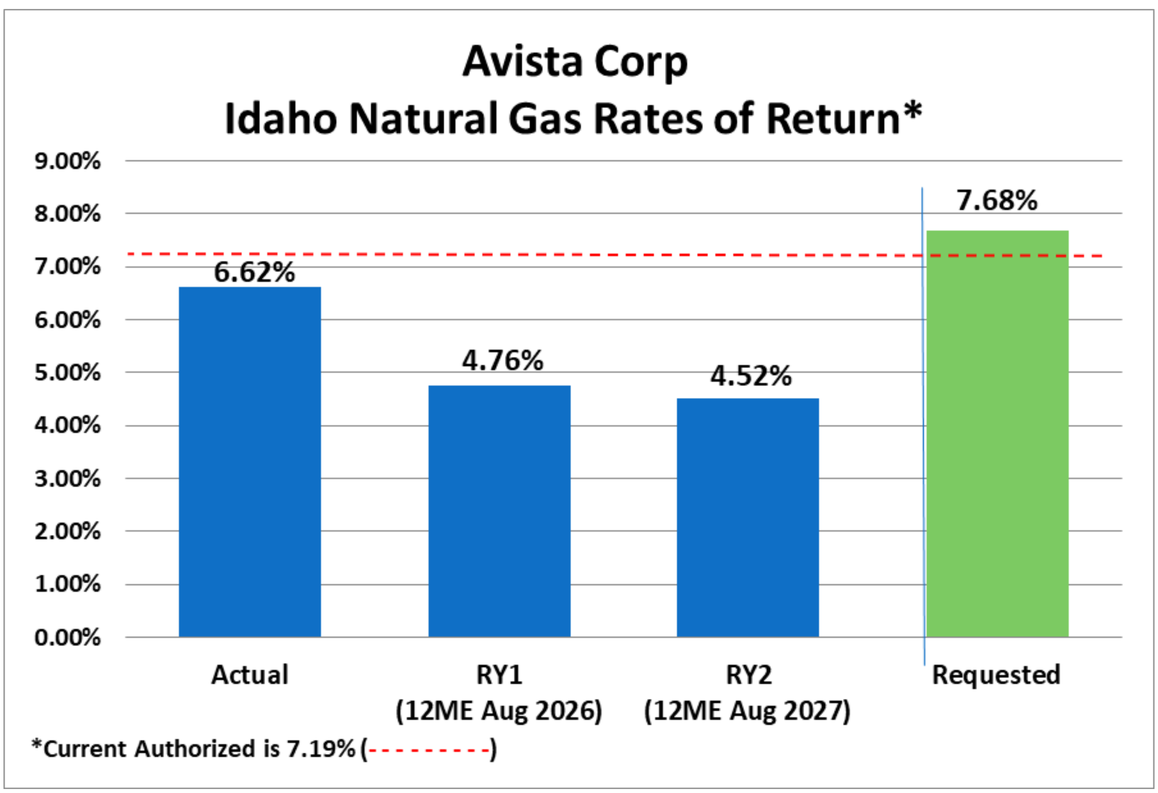


Illustration No. 2: Two-Year Rate Plan – Natural Gas Rates of Return



The incremental revenue requirement necessary to give the Company an opportunity to earn its requested ROR in RY1 is $42,951,000 or 14.0% base (14.4% billed) for its electric operations, and $8,803,000 or 17.7% base (10.3% 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 $17,674,000 or 5.0% base (5.2% billed) for its electric operations, and $983,000 or 1.7% base (1.0% billed) for its natural gas operations. Table No. 2 below provides a summary of the RY1 and RY2 requested revenue requirement and percentage increases.

Table No. 2 – Revenue Requirement and Percentage Increases

Two Year Rate Plan Revenue Requirement ($ 000's) & Percentage Increases						
Service	**RY1**			**RY2**		
	Revenue	**Base %**	**Billed %**	**Revenue**	**Base %**	**Billed %**
Idaho Electric	$ 42,951	14.0%	14.4%	$ 17,674	5.0%	5.2%
Idaho Natural Gas	$ 8,803	17.7%	10.3%	$ 983	1.7%	1.0%

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 7.19%, effective September 1, 2023, per Case Nos. AVU-E-23-01 and AVU-G-23-01.

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, including the removal of Colstrip effective January 1, 2026, also contribute significantly to the incremental electric revenue requirement. Other changes impacting the Company's revenue requirement requests relate to proposed regulatory amortizations, incremental increases in wildfire expense and insurance expense baselines (as discussed and sponsored by Ms. Andrews), as well as 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. Table No. 3 provides a summary-level breakdown of the revenue requirement components.

Table No. 3 – Revenue Requirement Summary

ID Electric Revenue Requirement	**RY1 Electric**	**RY2 Electric**
Capital & Other (Labor, Benefits, O&M, etc.)	$ 25,356	$ 11,081
Net Power Supply (including Transmission Revenues)	$ 7,187	$ 9,020
Updated Baselines		
Incremental Wildfire Baseline	$ 1,103	
Incremental Insurance Baseline	$ 5,547	
Regulatory Amortizations	$ 3,872	
Net Colstrip Amortization/Removal	$ (114)	$ (2,427)
Proposed Revenue Requirement	**$ 42,951**	**$ 17,674**
ID Natural Gas Revenue Requirement	**RY1 Gas**	**RY2 Gas**
Capital & Other (Labor, Benefits, O&M, etc.)	$ 5,584	$ 983
Updated Insurance Baseline	$ 386	
Regulatory Amortizations	$ 2,833	
Proposed Revenue Requirement	**$ 8,803**	**$ 983**

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 $115.0 million for electric, and approximately $33.6 million for natural gas, as compared to what is currently embedded in base retail rates.[3] For RY2, gross plant increases by approximately $72.6 million for electric, and approximately $11.1 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. 4 as follows:

Table No. 4 – Gross Plant Additions

Gross Plant Additions (000s)						
	Electric				Total Over	
Investment	**RY1[1]**		**RY2[2]**		**2-YR Plan**	
Generation/Transmission	$	284	$	21	$	305
Distribution	$	119,793	$	65,117	$	184,910
General & Intangible[4]	$	(5,096)	$	7,491	$	2,395
Total Electric Gross Additions	$	114,981	$	72,629	$	187,610
Net Plant Additions[3]	$	117,661	$	72,895	$	190,556
	Natural Gas				Total Over	
Investment	**RY1[1]**		**RY2[2]**		**2-YR Plan**	
Distribution	$	27,426	$	8,611	$	36,037
General & Underground Storage	$	6,208	$	2,442	$	8,650
Total Natural Gas Gross Additions	$	33,634	$	11,053	$	44,687
Net Plant Additions	$	21,432	$	6,443	$	27,875

[1]RY1 - Effective September 1, 2025 - August 31, 2026

[2]RY2 - Effective September 1, 2026 - August 31, 2027

[3]Total gross plant and accumulated depreciation (net plant) are lower than they otherwise would be based solely on new capital additions, due to the removal of Colstrip effective January 1, 2026, impacting both RY1 (removal of 8 months) and RY2 (removal of 4 months).

[4]General and intangible gross plant additions are impacted by the retirement of shorter lived assets.

The specific July 2024 through August 2027 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. Howell regarding generation/production and environmental investment, Mr. Kinney regarding the Company's investment in Colstrip Units 3 and 4, Mr. DiLuciano regarding transmission, distribution and

[3] Current embedded base retail rates include most net plant additions through December 31, 2024 for electric and natural gas base rates on an EOP basis.

general investment, Mr. Manuel regarding the costs associated with Avista's IS/IT projects, and Mr. Malensky regarding Wildfire Plan investments.

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.[4]

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 \$12.2 million (\$29.3 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 \$9.5 million (\$26.8 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 \$5.2 million (\$14.0 million on a system basis) from the level currently included in base rates. Idaho pro forma transmission revenue, however, increases by \$528,000 (\$1.5 million on a system basis) in RY2, versus that included in RY1.[5]

Therefore, the net change in power supply expense and transmission revenues result in an overall net increase in electric costs of approximately \$7.2 million in RY1 and \$9.0 million in RY2.

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[4] With the exception of the Pro Forma Colstrip Unit 3 and 4 investment and regulatory amortization included in Pro Forma Adjustments 3.15 discussed and sponsored by Ms. Andrews. The Colstrip Unit 3 and 4 generation capital additions in 2024 and 2025 are sponsored by Mr. Kinney.

[5] See Mr. Dillon's direct testimony, footnotes 2 and 3.

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, increases in insurance related to higher premiums, as a result of wildfires across the country, as well as increases in labor and benefits. 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, 2024 Test Year.

III. DERIVATION OF TWO-YEAR RATE PLAN REVENUE REQUIREMENT

Test Period for Ratemaking Purposes

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

A. The historical test period being used by the Company is the twelve-month period ending (12ME) June 30, 2024 (Test Period), presented on a 12ME August 31, 2026 (RY1) and August 31, 2027 (RY2) pro forma basis. Current authorized electric and natural gas rates for the existing two-year rate plan effective September 1, 2023, were based upon the 12ME June 30, 2022 test year utilized in Case Nos. AVU-E-23-01 and AVU-G-23-01, 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, 2024 actual operating results and components of the average-of-monthly-average (AMA) rate base as recorded[6]; 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 7.68% rate of return for RY1. Column (f) reflects RY1 pro forma operating results with the requested increase of $42,951,000 for electric and $8,803,000 for natural gas.

<u>Page 2</u> of Exhibit No. 4, Schedules 1 and 2, show similar columns starting with RY1 (09.2025 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 (09.2026 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 7.68% rate of return for RY2. Column (g) reflects RY2 pro forma operating results with the requested increases of $17,674,000 for electric and $983,000 for natural gas, above that requested in RY1.

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[6] Actual <u>plant</u> rate base (cost, accumulated depreciation (A/D) and accumulated deferred federal income taxes (ADFIT)) uses the 06.2024 AMA balances. Plant rate base is adjusted to 08.2026 AMA basis for RY1, and 08.2027 AMA basis for RY2, with restating and pro forma adjustments.

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 $42,951,000 and $17,674,000, respectively. Page 3 of Exhibit No. 4, Schedule 2, shows the RY1 and RY2 revenue requirement calculations for natural gas of $8,803,000 and $983,000, 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 7.68%. Company witness Mr. Christie discusses the Company's proposed rate of return and the pro forma capital structure utilized in this case, while Company witness Dr. Thompson 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 0.786572. The conversion factor includes uncollectible accounts receivable, Commission fees and Idaho State income taxes.[7] 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 historical test period in column (1.00). Individual Commission Basis normalizing and restating adjustments that are 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.

[7] Due to net operating loss (NOL) carryforwards, the Company anticipates it will pay the minimum state income tax in Idaho through 2026 with the Idaho NOL fully utilized by 2027.

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 (3.16) on page 9, with the "RY1 09.2025 FINAL TOTAL" column on page 9 representing the total pro forma operating results and net rate base for the RY1 pro forma period (effective 09.2025). Page 10 of Exhibit No. 4, Schedule 1, includes RY2 pro forma adjustment columns (26.00P) through (26.06). Additional RY2 pro forma adjustment columns (26.07) and (26.11) are shown on page 11, along with the "RY2 09.2026 FINAL TOTAL" and "RY2 INCREMENTAL 09.2026 I Above 09.2025 TOTAL" columns, representing the total pro forma operating results and net rate base for the RY2 pro forma period (effective 09.2026), 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 (3.13), with the "RY1 09.2025 FINAL TOTAL" column on page 9 representing the total pro forma operating results and net rate base for the RY1 pro forma period (effective 09.2025). Page 10 of Exhibit No. 4, Schedule 2, includes RY2 pro forma adjustment columns (26.01) through (26.06). Additional RY2 pro forma adjustment columns (26.07) and (26.08) are shown on page 11, along with the "RY2 09.2026 FINAL TOTAL" and "RY2 INCREMENTAL 09.2026 I Above 09.2025 TOTAL" columns, representing the total pro forma operating results and net rate base for the RY2 pro forma period (effective 09.2026), 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-23-01 and AVU-G-23-01), 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 in electronic format 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 an increase of $3,022,000 electric, and an increase of $589,000 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[8] is an increase of $16,000 for electric and an increase of $3,000 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 impact on NOI and rate base.

Adjustments included in the Deferred Debits and Credits consolidated adjustment are those necessary to reflect restatements from 12ME June 30, 2024 actual results (included in column 1.00 "Per Results of Operations"), based on prior Commission orders as explained below.

- **Boulder Park Disallowance (electric)** 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 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. To reflect the actual electric AMA balance as of 12ME June 30, 2024 for the disallowance amount remaining of $206,970, an adjustment to increase rate base is necessary of approximately $7,000. The normalized expense for the test period, however, is accurate as recorded within results of operations.

- **Restating Montana Riverbed Lease (electric)** reflects the costs associated with the Montana Riverbed lease settlement. In the Montana Riverbed lease settlement, the Company agreed 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 (pro rated for RY1) as previously required, increasing expense by $165,000.

- **Weatherization and DSM Investment (electric)** includes in rate base the Sandpoint weatherization grant (loan) balance (FERC account 124.350) remaining as of the 12ME June 30, 2024 test period on an AMA basis of approximately $7,000. The balance as of June 30,

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

2023 of $59,000 was written off, per Stipulation and Settlement Agreement in Case No. AVU-E-23-01, in the second half of 2023, leaving this small portion ($7,000) within the 12ME June 30, 2024 test period on an AMA basis. To remove this balance, a rate base adjustment of $7,000 is necessary.

- **<u>Customer Advances (electric)</u>** increases 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. To reflect the proper balances for Customer Advances for the 12ME June 30, 2024 test period, rate base is increased by approximately $3,000.

Finally, this adjustment removes electric and natural gas non-reoccurring deferred expenses or expiring regulatory amortizations included in the 12ME June 30, 2024 test period. Items being removed, increasing regulatory amortization expense, are as follows: the Tax Reform Amortization for electric of $55,000, the COVID-19 Deferral Amortization for electric of $228,000 and for natural gas of $25,000, and the Williams Pipeline Outage deferral expense for natural gas of $2,677,000. Items being removed, decreasing regulatory amortization expense, are as follows: Energy Imbalance Market (EIM) Amortization for electric of $291,000, FISERVE Amortization for electric of $97,000 and for natural gas of $158,000, the Depreciation Study Deferral for electric of $313,000 and natural gas of $103,000, and the AFUDC Equity deferred federal income taxes (DFIT) Deferral expense for natural gas of $25,000.[9]

In summary, the net impact on a consolidated basis of this adjustment, for Idaho electric, decreases NOI by $470,000 and increases rate base by $3,000, and for natural gas, decreases NOI by $1,909,000. No adjustment is necessary for Idaho natural gas rate base.

Electric Adjustment (1.03) and Natural Gas Adjustment (1.03) - **Working Capital**,

[9] The Depreciation Study and Williams Pipeline Outage deferrals are included as proposed two-year regulatory amortizations in this case. See Adj. 3.11 – Pro Forma Regulatory Amortizations discussed later in my testimony for more information.

restates the working capital balance reflected in the Company's Results of Operations column (1.00) on a 12ME June 30, 2024 test period AMA basis, to the adjusted working 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-23-01 and AVU-G-23-01, respectively, and was used for both electric and natural gas results.[10] The impact of this adjustment resulted in a decrease to electric rate base of $923,000 and a decrease to natural gas rate base of $205,000. This adjustment also decreases electric NOI by $5,000 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 06.2024 EOP,** restates the capital investment and expenses associated with adjusting the 12ME June 30, 2024 AMA plant related balances to June 30, 2024 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 $27,730,000 for electric and $4,973,000 for natural gas. The effect on Idaho NOI are increases of $144,000 for electric and $26,000 for natural gas related to the federal income tax effect of debt interest.

[10] 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 the Company's last Idaho electric and natural gas general rate cases, Case Nos. AVU-E-23-01, and AVU-G-23-01.

Electric Adjustment (2.01) and Natural Gas Adjustment (2.01) - **Eliminate B & O Taxes**, require no change from test period results. Test period results for B & O taxes eliminates the revenues and expenses associated with local business and occupation (B & O) taxes, which the Company passes through to its Idaho customers. This adjustment has no impact on electric and natural gas NOI.

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 $149,000 and $91,000, 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 $82,000 and $27,000, 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 $139,000 and natural gas NOI by $10,000.

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.[11]

Electric Adjustment (2.06) and Natural Gas Adjustment (2.06) - **SIT/SITC Expense**, requires no change from test period results. Test period results reflect the appropriate 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-23-01 and AVU-G-23-01. 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 (NOL) carryforwards, the Company expects to incur no SIT expense through 2026 with the Idaho NOL fully utilized by 2027. To be conservative, the Company has excluded SIT tax within the conversion factor for the Two-Year Rate Plan.

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 66 Power Cost Adjustment, Schedule 75 Fixed Cost Adjustment, Schedule 76 Tax Customer Credit, Schedule 91 Public Purpose Tariff Rider, and

[11] After completion of the Company's revenue requirement, it was discovered that the expected level of RY1 investment tax credit (ITC) amortization would be higher than the historical test period ITC amortization, resulting in lower income tax expense of approximately $41,000 for Idaho electric. The Company has provided the correct workpapers in its filed case, but will reduce the Idaho electric revenue requirement by $52,000 for this update during the pendency of this case.

Schedule 95 Optional Renewable Power, are excluded from pro forma revenues, and the related amortization expense is eliminated as well. In addition, the revenues and expenses associated with the Clearwater Purchase and Sale Agreement and the amortization of the earnings test deferral amortization approved in the 2023 General Rate Case are 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 $7,605,000 and $1,196,000, 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. This adjustment also normalizes historical test year pole rental revenue for one-time invoices assessed for back rent recorded in the fourth quarter of 2023 related to unauthorized attachments that were found during the Company's 2023 system-wide pole audit. Additionally, this adjustment removes historical test year O&M expenses associated with the Williams Northwest Pipeline Emergency Operations Plan (EOP) dig-in event, a one-time, non-reoccurring event discussed later in my testimony under electric and natural gas Pro Forma Adjustments 3.11 – Regulatory Amortizations. The net effect of this adjustment decreases electric NOI by $736,000 and increases natural gas NOI by $1,514,000.

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, 2024 test period to reflect a six-year average (2018-2023) of actual payout amounts.

Incentive compensation is comprised of two plans, 1) the Senior Leader Plan[12], which includes executives, directors and senior legal counsel participating in the Long-Term Incentive Plan (LTIP) and 2) the Employee Plan, composed of all other eligible employees not included in the Senior Leader Plan. The six-year average of incentive compensation expense payout is $4.9 million (system) for the Employee Plan (<u>non-senior leader employees)</u> based on 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 $0.85 million (system) in operating expenses.[13] 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-senior leader and senior leader expense, decreases Idaho NOI by approximately $377,000 for electric and $100,000 for natural gas.

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

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[12] Prior to January 1, 2024, Directors and Senior Legal Counsel were included in the Employee Incentive Plan. As of January 1, 2024, the Executive Plan was expanded to the Senior Leader Plan as discussed further below.
[13] With the change to the Senior Leader Plan effective January 1, 2024, the six-year average (2018-2023) for Executives/Senior Leaders is based on the Executive Plan, prior to incorporating Senior Leaders. Expense associated with Senior Leaders for January through June 2024 of the 12 ME 06.2024 test year on an Idaho electric and natural gas basis is approximately $38,000 and $10,000, respectively.

A. In accordance with the Company's overall compensation design to align elements of incentive plans among all Company employees including senior leaders, the Employee STIP plan has essentially the same stated goals as the Short-Term Incentive Plan for senior leaders (Senior Leader 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 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 Senior Leader STIP.

A. The Senior Leader STIP is designed to align the interests of senior leaders with both customer and shareholder interests in order to achieve overall positive operating and financial performance for the Company. The Senior Leader STIP includes all executive officers ("officers") hired prior to October 1st and actively employed on the last day of the plan year and all directors and senior legal counsel employees ("non-officers") currently participating in the company's Long-Term Incentive plan.

The Senior Leader STIP for officers has five operational components, plus an earnings per share (EPS) component. The total amount associated with utility operational components is 45% and is broken down as follows: 20% O&M Cost-Per-Customer, 8% Customer Satisfaction, 8% Reliability, 4% Response Time, and 5% Equity, Inclusion, and Diversity

Scorecard. The Consolidated Diluted Utility EPS components accounts for 55% of the total opportunity. Only the operational components (45%) 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 55% of the Senior Leader officer STIP related to Utility EPS and targets is borne by shareholders.

The Senior Leader STIP for non-officers has five operational components, plus an earnings per share (EPS) component. The total amount associated with utility operational components is 80%, broken down as follows: 55% O&M Cost-Per-Customer, 8% Customer Satisfaction, 8% Reliability, 4% Response Time, and 5% Equity, Inclusion, and Diversity Scorecard. The Consolidated Diluted Utility EPS components accounts for 20% of the total opportunity. Only the operational components (80%) 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 20% of the Senior Leader non-officer STIP related to Utility EPS 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 Employee STIP, 45% of the Senior Leader STIP for officers (excluding metrics related to EPS targets), and 80% of the Senior Leader STIP for non-officers (excluding metrics related to EPS 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, and customer and community impact as measured by the Senior Leader STIP Equity, Inclusion, and Diversity Scorecard. 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 Utility EPS portion of Senior Leader 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 LTIP is comprised of two components, which serve two different purposes.[14] Performance Shares account for 70% 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 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, one quarter of the performance awards are contingent on TSR relative to our peers, and three-quarters is measured by our CEPS over a three-year period. The Company has excluded the costs associated with the Performance Share portion of the LTIP from the

[14] As with all other components of the executive compensation, the Compensation Committee of Avista's Board of Directors 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.

revenue requirement in this case.

Restricted Stock Unit (RSU) awards account for 30% 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 $762,000 for electric and $211,000 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 (3.00P) Power Supply, respectively. The effect of this adjustment increases Idaho electric NOI by $6,043,000.

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 $20,000.

Electric Adjustment (2.12) – **Colstrip/CS2 Maintenance**, as discussed and sponsored by Ms. Andrews, reflects the accounting treatment for deferred non-fuel O&M expenses for Colstrip and Coyote Springs 2 ("CS2") as approved in Order 32371 on September 30, 2011 (in Case No. AVU-E-11-01 and AVU-G-11-01). Per Order 32371, the Company deferred the non-fuel O&M costs associated with the Company's Colstrip and CS2 thermal generating plants representing the difference between actual O&M costs and the authorized "Base O&M" costs (currently $20.4 million on a system basis) for each respective year. Included in the 12ME 06.30.2024 historical test period level are the three-year amortizations of the Idaho deferrals from years 2020-2023 totaling approximately $890,000.[15] Calculated RY1 amounts include the three-year amortizations of the Idaho deferrals from years 2022-2023 and estimated for 2024-2025, on a pro rata basis, totaling approximately $2.0 million.

[15] In addition, in 2022 the Company received $2.5 million in insurance proceeds related to a CS2 insurance claim filed in 2018 due to the failure of equipment at the CS2 natural gas generating facility. 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, which were netted together with the estimated 2022 deferral, impacting deferral years 2022-2024.

Adjusting expense in RY1 to the pro rata share of years 2025 and 2026 (including one-third of each amount deferred (actual or estimated) for calendar years 2022 through 2023 and 2024 through 2025, respectively), increases Idaho regulatory amortization expense $1,083,000, and decreases NOI by $856,000.[16]

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. Christie. 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 $964,000 and natural gas NOI by $196,000.

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.

[16] See Pro Forma Adjustment 26.09, which adjusts Colstrip/CS2 maintenance amounts reflected in RY1, to reflect the pro rata share of years 2026 and 2027, which include one-third of each amount deferred (actual or estimated) for calendar years 2023 through 2025 and 2024 through 2026, respectively, to reflect Colstrip/CS2 maintenance amounts expected in RY2.

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, in electronic format, 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 (09.2025 – 08.2026) – 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, 2025 through August 31, 2026 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 decreases electric NOI by $10,539,000.[17]

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, 2025 through August 31, 2026. The net effect of this adjustment increases electric NOI by $47,000.[18]

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 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;

[17] See Pro Forma Adjustment 26.00P, which adjusts pro forma power supply amounts reflected in RY1, to reflect pro forma power supply amounts expected in RY2.
[18] See Pro Forma Adjustment 26.00T, which adjusts pro forma transmission-related revenues and expenses to reflect pro forma transmission-related revenue/expense amounts expected in RY2.

- 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, 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[19] 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, overall salary increase recommendations are presented to the independent Compensation Committee of the Board of Directors (Board) for their consideration and approval. The Board 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 bargaining and non-bargaining wages and salaries, excluding executive salaries, which are handled separately in Pro Forma Adjustment (3.02). For non-bargaining employees, the adjustment annualizes the impact of the actual increase effective March of 2024 (5%) and the Board approved increase effective March of 2025. In addition, the Company has applied an expected prorated March 2026 increase through August 31, 2026, for total labor expense levels in RY1.[20] / [21]

Bargaining Unit employee increases are made in accordance with contract terms. In the Pro Forma Labor Non-Exec Adjustment (3.01), the Company annualizes the impact of

[19] "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/

[20] See CONFIDENTIAL 3.01 & 26.04 Non-Executive Labor Adjustment workpaper, Pro-Forma Increases tab for annualized Bargaining and Non-Bargaining labor increases by year.

[21] In Q1 2025, the Board approved a minimum increase for 2026.

the 2024 increase of 5.00%, effective March 26, 2024[22], and reflects the 2025 increase of 5.00% contractually agreed to, effective January 1, 2025 through March 25, 2026. The current contract with the IBEW Local 77 Bargaining Unit (Local 77) (Idaho/Washington) expires on March 25, 2025. Although the contract will expire and the Company will enter into negotiations with the Local 77 in 2025, the agreed to labor increases will remain effective through March 25, 2026. The Company has included estimated merits for 2026 and 2027 consistent with non-bargaining employees. In total, this adjustment represents an increase in Idaho expense in RY1, effective September 1, 2025 ending August 31, 2026, of $3.19 million electric and $0.90 million natural gas. The effect of this adjustment decreases Idaho NOI by $2,518,000 for electric and $711,000 for natural gas.[23]

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 2024, 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, 2024 levels actual percentages (95% utility /5% non-utility). This adjustment also reflects changes (retirements and additions) in officer placements and their impact on salary expense from the test period to the rate-effective period. The impact of this adjustment decreases Idaho expense by $68,000 for electric and $18,000 for natural gas.

The Compensation Committee of the Board of Directors (Board) determined and

[22] As of August 2024, the Company and Local 77 ratified an agreement retroactively paying the Bargaining Unit's 2024 5% merit increase effective March 26, 2024 and setting the 2025 increase of 5% effective January 1, 2025 through March 25, 2026. The Company is annualizing the general wage increase (GWI), as none was included in the Company's historical test period (12ME 06.2024) due to timing.
[23] See Pro Forma Adjustment 26.04, which adjusts pro forma non-executive labor amounts reflected in RY1, to reflect incremental pro forma non-executive labor amounts expected in RY2.

approved the executive officer level of base salary effective March 2024, 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 increases Idaho NOI by $54,000 for electric and $14,000 for natural gas.

Electric Adjustment (3.03) and Natural Gas Adjustment (3.03) – **Pro Forma Employee Benefits**, adjusts the 12ME June 30, 2024 Retirement Plans (401(k) and Pension), and medical insurance for active employees and those retired (post-retirement medical) to the expected amount for RY1, effective September 1, 2025 through August 31, 2026. Annually, the Company works with independent consultants 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. 5 below:[24]

Table No. 5: Benefit Adjustment for RY1

Benefit Adjustment	RY1		
	System O&M	ID Electric	ID Natural Gas
Medical	$ 3,641,755	$ 814,609	$ 217,115
Retirement	$ 1,818,200	$ 406,706	$ 108,398
Total	$ 5,459,955	$ 1,221,315	$ 325,513

The Company offers a comprehensive benefit plan for employees. Employees have

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

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 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, 2024 test period to reflect what will be in effect during RY1, resulting in an overall <u>system expense</u> increase of $1.8 million.[25] 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 changes in pension expense are related to changes in asset value due to the actual return on assets, changes in the discount rate and the expected long-term return on assets for the year 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 2024.[26] We anticipate

[25] See Pro Forma Employee Benefits Adjustment 26.07, which adjusts pro forma employee benefit amounts reflected in RY1, to reflect pro forma employee benefit amounts expected in RY2. The incremental overall <u>system expense</u> in RY2 for the Company's retirement portion is an increase of approximately $519,000.
[26] The estimate for 2023 was used as the basis for the rate effective period.

updates for 2025 through 2026 to be available from our actuary sometime in the first quarter of 2025, and the Company will adjust pension expense at that time to reflect a prorated amount for RY1, 12ME August 31, 2026.

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[27], as discussed in Pro Forma Labor Non-Exec Adjustment (3.01), resulting in an increase in 401(k) and pension expense on a system basis of $1.8 million for RY1.[28] Over the long term, we anticipate a decrease in pension expense will reduce overall retirement net expense.

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-bargaining employees hired or rehired on or after January 1, 2014.[29] All actively employed non-bargaining 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,

[27] See CONFIDENTIAL 3.01 & 26.04 Non-Executive Labor Adjustment workpaper, Pro-Forma Increases tab for detailed, annualized Bargaining and Non-Bargaining labor increases by year.

[28] See Pro Forma Employee Benefits Adjustment 26.07, 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) and pension expense on a system basis in RY2 is approximately $519,000.

[29] Changes were applicable to Local 659 effective April 1, 2014.

2024.[30] A defined contribution 401(k) plan replaced the defined benefit pension plan for all non-bargaining and IBEW Local 659 Bargaining Unit (Local 659) (Oregon) 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-bargaining retirees under the defined benefit pension plan to provide non-bargaining 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 also applies to Local 77. Additionally, starting January 1, 2024, newly hired Local 77 bargaining unit employees also receive a 5% enhanced Company contribution based on their base wage in place of the short-term incentive.[31] Those who were covered under the defined benefit pension plan previously, will 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

[30] Changes were applicable to the Local 77B (DO/GC) bargaining unit (Distribution Operations and Gas Controllers) with their contract placement in 2017.
[31] In alignment with contract ratification, in 2024 the Company offered all employees the opportunity to vacate the Pension Plan for the enhanced 401(k) option. Under the contract agreement, bargaining unit employees who opted for the enhanced 401(k) are no longer eligible for the short-term incentive as well.

premiums[32] for the Company are estimated by an independent consultant, Mercer,[33] 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 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

[32] In this context, "premium" is defined as total medical costs including both the Company and employee contribution.
[33] Mercer is currently the world's largest human resources consulting firm, with more than 20,500 employees, based in more than 40 countries.

In this case, the primary contributor to the change in expense is related to a change in cost trend assumptions. We anticipate updates for 2025 to be available sometime in the first quarter of 2025, 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 an increase in RY1 system expense of approximately $3.6 million.[34]

As shown in Table No. 5 above, the overall net impact of changes in retirement and medical expense on a system basis for RY1 is an increase of $5.5 million, or $1.2 million Idaho electric and $326,000 Idaho natural gas.[35] Therefore, the Pro Forma Employee Benefits Adjustment (3.03) decreases Idaho NOI by $965,000 for electric and $258,000 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 2025.

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, 2024 test year to reflect expected expense increases in the twelve-month period September 1, 2025 through August 31, 2026. IS/IT and Security increases in expense have been pro formed first, using a narrowed scope of incremental expenses to known and measurable items that will be in place over the

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[34] See Pro Forma Employee Benefits Adjustment 26.07, 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 system basis in RY2 is approximately $906,000.

[35] See Pro Forma Employee Benefits Adjustment 26.07, which adjusts pro forma employee benefit amounts reflected in RY1, to reflect pro forma employee benefit amounts expected in RY2. Refer to Table No. 6 for the overall net impact of changes in pension and medical expense on a system basis for RY2.

Two-Year Rate Plan beginning in September 2025, reflecting an increase of approximately $1.03 million system. These increased expenses represent non-labor impacts of annual and multiyear contractual agreements for products and services, licensing, and maintenance fees for a range of centralized information services. These incremental expenditures are necessary to support the Company's cyber and general security, emergency operations readiness, electric and natural gas facilities and operations support, and customer services. This increase in IS/IT expense represents an overall 4.9% increase in known and measurable IS/IT expenses in RY1 above the 12ME June 30, 2024 test year levels.

In addition, the Company has also included incremental expected increases in IS/IT expenses, mainly associated with general business systems, totaling approximately $399,000 system in RY1, as discussed by Mr. Manuel. This incremental increase reflects an expected increase in IS/IT expense above test year levels of approximately 1.9% annually over the Two-Year Rate Plan. Mr. Manuel sponsors this adjustment and provides more information within his testimony. The effect of this adjustment decreases NOI by $201,000 for electric and by $43,000 for natural gas.[36]

Electric Adjustment (3.05) and Natural Gas Adjustment (3.05) – **Pro Forma Property Tax**, restates the 12ME June 30, 2024 test period accrued levels of property taxes to the RY1 property tax expense levels, based on prorated property values as of December 31, 2024 (2025) and December 31, 2025 (2026) for the rate effective period (September 1, 2025 – August 31, 2026). The property tax balances include estimates for 2024-2026 and the

[36] See Pro Forma Adjustment 26.08, which adjusts Pro Forma IS/IT Adjustment 3.04 amounts reflected in RY1, to include incremental IS/IT expenses planned in RY2 above RY1 levels.

Company will update with more current estimates through the process of the case. The net effect of this adjustment decreases NOI by $562,000 electric and $668,000 natural gas.[37]

Electric Adjustment (3.06) and Natural Gas Adjustment (3.06) – **Pro Forma Insurance Expense,** as discussed and sponsored by Ms. Andrews, reflects increases from 12ME June 30, 2024 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 2024 for the Company's general and property insurance premiums, and estimated March 2025 for D&O and other insurance premiums were used to further estimate the planned insurance expense levels over the Two-Year Rate Plan. The Company will update any 2024/2025 estimated amounts, as well as updated insurance expense levels expected over the Two-Year Rate Plan included in this case, as soon as the remaining actual invoices in 2024/2025 are available. The effect of the electric and natural gas insurance adjustments (PF 3.06) increases insurance expense by $4,065,000 for electric and $282,000 for natural gas, above test period levels. This results in pro formed electric and natural gas insurance expense levels of approximately $9,556,000 and $1,100,000, respectively.[38]

This adjustment also removes non-recurring test period deferred regulatory credit expense from the test period (removes FERC Account 407 balances), related to deferring insurance expenses during the period July 1, 2023 through June 30, 2024, increasing

[37] See Pro Forma Adjustment 26.03, which adjusts Pro Forma Property Tax Adjustment 3.05 amounts reflected in RY1, to include incremental 2026 and 2027 Property Tax expenses, on a pro rata basis, planned in RY2 above RY1 levels.

[38] As discussed by Ms. Andrews, the pro formed level of electric and natural gas insurance expense proposed in this case also reflects the Company's proposed Insurance Expense Balancing Account baselines for Idaho electric and natural gas of $9,556,000 and $1,100,000, respectively over the Two-Year Rate Plan.

administrative and general (A&G) Regulatory Amortization expense by $1,874,000 for electric and $78,000 for natural gas. The net of these adjustments increases related insurance expense by $5,939,000 for electric and $360,000 above test period levels and decreases NOI by $4,692,000 for electric and $234,000 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, 2024 test period to reflect the level of EDIT amortization expense expected for the rate effective period. 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).[39] Consistent with that incorporated in the Company's last electric and natural gas general rate cases, Case Nos. AVU-E-23-01 and AVU-G-23-01, respectively, the Company's filed revenue requirement in this case utilizes the RSGM for both rate years. The effect of this adjustment decreases electric NOI by $357,000 and natural gas NOI by $20,000.[40]

Electric Adjustment (3.08) and Natural Gas Adjustment (3.08) – **Pro Forma Capital Additions 08.2025 EOP**, as discussed and sponsored by Ms. Benjamin, reflects July 1, 2024

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[39] The Company discussed the change in method of amortizing EDIT from Average Rate Assumption Method (ARAM) to the Reverse South Georgia Method (RSGM) in its 2023 electric and natural gas general rate cases, Case Nos. AVU-E-23-01 and AVU-G-23-01, respectively.

[40] See Pro Forma Electric Adjustment 26.11, which adjusts pro formed EDIT amortization expense in RY2, from RY1 levels, for the removal of remaining Colstrip balances in RY2.

through August 31, 2025 capital additions[41] together with the associated A/D and ADFIT at an August 31, 2025 EOP basis. This adjustment also includes associated depreciation expense for these additions, as well as, incremental annualized depreciation expense on plant-in-service at June 30, 2024. In addition, the plant-in-service at June 30, 2024 EOP was adjusted to an August 31, 2025 EOP basis. Finally, retirements for the fourteen months-ended August 31, 2025 on plant-in-service at June 30, 2024 were pro formed reducing depreciation expense, which was included in the overall impact of this adjustment. The effect of this adjustment increases Idaho electric and natural gas rate base by $51,511,000 and $6,589,000, respectively. The effect of this adjustment on Idaho NOI is a decrease of $1,512,000 electric and $91,000 natural gas.

Electric Adjustment (3.09) and Natural Gas Adjustment (3.09) – **Pro Forma Capital Additions 08.2026 AMA**, as discussed and sponsored by Ms. Benjamin, reflects September 1, 2025 through August 31, 2026 capital additions together with the associated A/D and ADFIT at an August 31, 2026 AMA basis. This adjustment also includes associated depreciation expense for these additions. In addition, the plant-in-service at August 31, 2025 EOP was adjusted to an August 31, 2026 AMA basis. Finally, retirements for the twelve months-ended August 31, 2026 on an AMA basis on plant-in-service at August 31, 2025, were pro formed reducing depreciation expense, which was included in the overall impact of this adjustment. The effect of this adjustment increases Idaho electric and natural gas rate base

[41] For the period July 1, 2024 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 also included as revenue offsets within Pro Forma Adjustments 3.10 (RY1) and 26.05 (RY2) "Pro Forma Revenue & O&M Offsets."

$34,156,000 and $4,178,000, respectively. The effect of this adjustment on Idaho NOI is a decrease of $1,239,000 electric and $60,000 natural gas.[42]

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) – **Pro Forma Revenue and Operation & Maintenance (O&M) Offsets**. This adjustment 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. Howell, and Mr. Manuel, with the capital asset with which the net offset relates. The net effect of this adjustment increases NOI for electric by $2,974,000 and for natural gas by $1,186,000. As noted above, additional reductions in expense were reflected in Pro Forma Adjustments (3.08) and (3.09) (as well as pro forma adjustments (26.01) and (26.02)) with the inclusion of retirements in each electric and natural gas pro forma capital adjustment.

Electric Adjustment (3.11) and Natural Gas Adjustment (3.11) – **Pro Forma Regulatory Amortizations** reflects the proposal of amortizing several existing regulatory assets and liabilities – amounts either deferred and not yet amortized, or residual balances of previous amortizations, over a two-year period beginning September 1, 2025. A brief description of the regulatory assets and liabilities included in this adjustment are as follows:

[42] For pro forma capital additions included beyond RY1, refer to Pro Forma Capital Additions Adjustments (26.01) and (26.02) described below.

Avista Case No. AVU-E-23-06 (Order No. 35921 dated September 13, 2023) allowed the Company to defer, without a carrying charge, Idaho's Share of the interest expenses associated with the Montana Riverbed Lease Agreement in FERC Account No. 182.3. This adjustment proposes the approximately $573,000 of Idaho electric deferred costs, as of September 30, 2024, recorded in FERC Account 182377 – Regulatory Asset MT Riverbed Escrow Interest, be included in base rates and amortized for recovery over two years beginning September 1, 2025.

As a part of the Settlement Stipulation approved by the Commission in the Company's 2023 general rate case, Case No. AVU-E-23-01 (Order No. 35909 dated August 31, 2023), the Settling Parties agreed and the Commission approved to amortize the Company's two Wildfire Regulatory Deferred Asset balances (1) Wildfire Resiliency Plan Expense Deferral[43] and 2) Wildfire Expense Balancing Account deferral[44] (resulting from the deferral period July 1, 2020 through September 30, 2022 of $8.2 million), over four years beginning September 1, 2023. This adjustment proposes the incremental Idaho Wildfire deferred electric costs as of September 30, 2024, totaling approximately $6.5 million,[45] be included in base rates and amortized for recovery over two years beginning September 1, 2025. The deferred balance

[43] 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.

[44] In the Company's 2021 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. 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.

[45] The net Idaho electric proposed amortization of $6.5 million is comprised of approximately $10.6 million recorded in FERC Account 182353 – Regulatory Asset – Wildfire Balancing, less the expected remaining 2023 general rate case amortization through August 31, 2027 of $4.1 million.

will continue to accrue additional wildfire expense deferrals over time.[46]

Per the Company's last general rate case, Case Nos. AVU-E-23-01 and AVU-G-23-01 (Order No. 35909 dated August 31, 2023), as part of the Settlement Stipulation, the Commission approved a two-way Insurance Expense Balancing Account to defer the difference in actual insurance expense, up or down, from the authorized "base" level of insurance expense included of $4.009 million for electric and $714,000 for natural gas, effective September 1, 2023. This adjustment proposes the Idaho deferred costs, of approximately $2,748,000 for electric and the approximately $122,000 for natural gas, as of September 30, 2024, recorded in FERC Account 182359 – Regulatory Asset Insurance Balancing be included in base rates and amortized for recovery over two years beginning September 1, 2025. The deferred balance will continue to accrue additional insurance expense deferrals over time.[47]

As a part of the Company's 2023 Depreciation Study, Case Nos. AVU-E-23-02 and AVU-G-23-02 (Order No. 36020 dated December 8, 2023), the Company was ordered to defer the difference in Idaho electric and natural gas depreciation expense reflected in base rates beginning September 1, 2023, versus actual depreciation expense recorded on the Company's books of record, as a result of the approved change in depreciation rates becoming effective January 1, 2024, until a change in base rates occurs reflecting the overall revised depreciation

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[46] As discussed by Ms. Andrews, given the large wildfire expense deferral balances it has been experiencing over the last few years, and the higher carrying costs experienced by the Company to cover all its operating costs, as well as the delayed recovery of wildfire costs, the Company is requesting the Commission approve a carrying charge, effective September 1, 2025, on any existing deferred Wildfire balance and any new deferred balances going forward, at the Company's rate of return (ROR), and the Company's actual cost of debt, updated semi-annually (January 1 and July 1), while these balances are being amortized.

[47] As discussed by Ms. Andrews, given the large insurance expense deferral balances it has been experiencing over the last few years, and the higher carrying costs experienced by the Company to cover all its operating costs, as well as the delayed recovery of insurance costs, the Company is requesting the Commission approve a carrying charge, effective September 1, 2025, on any existing deferred insurance balance and any new deferred balances going forward, at the Company's rate of return (ROR), and the Company's actual cost of debt, updated semi-annually (January 1 and July 1), while these balances are being amortized.

rates in the Company's next general rate case. This adjustment proposes the Idaho deferred costs, of approximately $2,033,000 for electric and the approximately $550,000 for natural gas, as of September 30, 2024, recorded in FERC Account 254227 – Regulatory Liability Depreciation Expense be included in base rates and amortized for rebate over two years beginning September 1, 2025.

On November 8, 2023, Avista filed for deferred accounting treatment in Case No. AVU-G-23-08 related to a "dig in" event causing the Williams Northwest Pipeline (Williams) to shut down on the afternoon of November 8, 2023. As detailed in the Company's request, which was approved by the Commission in Order 36059 dated January 12, 2024, on November 8, 2023, Avista was notified that Williams, an interstate pipeline operator who transports natural gas from supply basins to the Company's distribution system gate stations, experienced a "dig in" by a third party. That dig in caused Williams to shut down its 12-inch pipeline, thereby ceasing delivery of natural gas to Avista's distribution system in the Pullman/Moscow and Lewiston/Clarkston general vicinities. This critical service was severely disrupted by the incident, which resulted in one of the largest natural gas outages in United States' history, affecting approximately 35,500 customers and causing significant financial harm to Avista due to our emergency response. Idaho accounted for 20,519 of the affected customers. The total costs of the outage to Avista were approximately $9.2 million, with 57.7 percent of that cost applied to Idaho (based on actual customers affected).

This adjustment proposes the Idaho natural gas deferred costs expected as of August 31, 2025, including deferred interest at the Company's cost of debt (as approved by the Commission), totaling approximately $5.8 million, recorded in FERC Account 186353 – Regulatory Asset – Williams Outage, be included in base rates and amortized for recovery over two years beginning September 1, 2025. The Company committed previously, and does so again here, to continue to seek any and all legal avenues to recover costs from the party who damaged the pipeline and cause the costs incurred. Any recovery down the road would be deferred and returned to customers at that time, should the Company prevail in its efforts.

For additional detail on the proposed amortizations included, please refer to my workpapers related to the Pro Forma Regulatory Amortizations Adjustment (3.11). The net effect of this adjustment is an increase in expense of $3,872,000 for electric and $2,851,000 for natural gas, annually over the Two-Year Rate Plan, resulting in a decrease in NOI of $3,059,000 for electric and $2,252,000 for natural gas.[48]

Electric Adjustment (3.12) and Natural Gas Adjustment (3.12) – **Pro Forma Misc. O&M Expense**, as discussed and sponsored by Ms. Andrews, reflects escalated increases in certain (or subset of) Company O&M and A&G expenses, from the 12ME June 30, 2024 test year through RY1, effective September 1, 2025, through August 31, 2026, not otherwise pro formed within the Company's electric or natural gas Pro Forma Studies. An annual escalation rate of 5.28% 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, 2024, through August 31, 2026 (or 2.17 years). All 12ME June 30, 2024 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, 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

[48] After completion of the Company's revenue requirement, the Company discovered it inadvertently included $2.851 million total natural gas regulatory amortization expense within its Natural Gas Pro Forma Model in error, rather than $2.833 million as shown in my workpapers. The effect of this inadvertent error overstates regulatory amortization expense by $18,000. The Company will correct this error during the process of the case.

charges); 9) locates expense; and 10) other expenses removed through restating adjustments (i.e., miscellaneous restating, eliminate adder schedule balances, gas supply costs, and revenue-related expenses). This adjustment, therefore, increases RY1 Idaho O&M expense by $3,384,000 for electric and $705,000 for natural gas, and decreases Idaho NOI by $2,673,000 for electric and $557,000 for natural gas.

The next electric and last natural gas RY1 adjustment is Electric Adjustment (3.13) and Natural Gas Adjustment (3.13) – **Pro Forma Locates Expense.** Avista utilizes One Call Locators, Ltd. (OCL), Vendor ID# 23737, to respond to 811 calls for locating services. With locate call-in data becoming more readily available and the recent growth in costs related to this vendor, the Company identified a need to reevaluate its methodology surrounding this vendor.

Historically, the Company has used a 50% capital and 50% operating (O&M) split to determine an OCL invoice's report category allocation. To determine an appropriate capital/O&M split, the Company obtained a list of locates tickets that were fulfilled by OCL and billed to Avista. This list was downloaded and compiled from the different 811 Call Centers by the Company's Damage Prevention group. Specifically, the analysts reviewed locate tickets from December 1, 2022 to November 30, 2023. After an initial review, management determined a need for a capital/O&M split percentage by state (WA, ID, and OR). To calculate this percentage, the Financial Planning & Analysis team assigned each locate ticket to O&M or capital. The list of tickets was split between "Avista Crew or Avista Contractor" and "3rd Party Contractor/Homeowner". The Company analysts assigned all locate tickets performed for "3rd Party Contractor/Homeowner" to O&M. <u>These locates are not related to work performed by the Company and, therefore, cannot be capitalized</u>. Further, the Company reviewed the remaining "Avista Crew or Avista Contractor" locate tickets.

Tickets with a description too vague to make a determination were separated for the capital/O&M population and split equally between capital and O&M.

In the end, it was clear the 50/50 traditional split no longer made sense, and a larger proportion of locate costs should be assigned to O&M. In total, this adjustment represents an increase in Idaho expense in RY1 beginning September 1, 2025, above test period levels, of $299,000 for Idaho electric and $322,000 for Idaho natural gas. The effect of this adjustment decreases Idaho NOI by $236,000 for Idaho electric and $254,000 for Idaho natural gas.

Electric Adjustment (3.14) – **Pro Forma Wildfire Plan Expenses**, as discussed and sponsored by Ms. Andrews, reflects the net increase in expenses associated with the Company's Wildfire Resiliency Plan ("Wildfire Plan"), as supported by Mr. Malensky.[49] Specifically, this pro forma adjustment increases 12ME 06.30.2024 test period distribution and transmission operating expenses by $585,000 to reflect Idaho's share of annual wildfire operating expenses expected during the Two-Year Rate Plan of $5,740,000.[50] 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, 2023 through June 30, 2024, increasing administrative and general (A&G) Regulatory Amortization expense by $1,189,000. The net of this adjustment increases related wildfire expense by $1,774,000 above test period levels, and decreases Idaho electric NOI by $1,401,000.

[49] Wildfire Plan capital additions, together with associated accumulated depreciation (A/D), accumulated deferred federal income taxes (ADFIT), and depreciation expense, from July 1, 2024, through August 31, 2027, over the Two-Year Rate Plan are included in Pro Forma Capital Additions Adjustments 3.08 and 3.09 in RY1, and Pro Forma Capital Additions Adjustments 26.01 and 26.02 in RY2, sponsored by Ms. Benjamin. Mr. Malensky discusses the need for these additions in his direct testimony.

[50] As discussed by Ms. Andrews, the pro formed level of Idaho electric wildfire expense proposed in this case also reflects the Company's proposed Wildfire Expense Balancing Account baseline of $5,740,000 over the Two-Year Rate Plan.

Electric Adjustment (3.15) – **Pro Forma Colstrip Regulatory Asset Additions and 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. This adjustment also reflects the Company's proposal to include the pro forma Colstrip capital additions for 2024 and 2025, and include this investment in the Colstrip Regulatory Asset for recovery over its authorized remaining amortization period (approximately 28 years). Mr. Kinney sponsors the Colstrip capital additions within his testimony and exhibits, which include descriptions of 2024 – 2025 capital additions ($6.45 million) that have been included in this general rate case, for prudency review in this proceeding (see Mr. Kinney's direct Testimony and Exhibit No. 6, Schedule 7C). The effect of this adjustment increases Idaho regulatory amortization expense by $221,000, increases Colstrip net plant by $4,793,000, above test period levels, and decreases electric NOI by $150,000.

The final RY1 adjustment is Electric Adjustment (3.16) – **Pro Forma Colstrip Assets and Depreciation Removal (effective 01/01/2026),** as discussed and sponsored by Ms. Andrews, reflects the impact of removing the net Colstrip investment (gross plant, offset by A/D) and depreciation expense <u>effective January 1, 2026</u>[51] from net plant in RY1 due to the transfer of the Colstrip plant to NorthWestern Energy as discussed by Mr. Kinney at the end of 2025, and recording (moving) the unrecovered net plant balance for Colstrip assets expected at December 31, 2025, to the Colstrip Regulatory Asset, for amortization over the remaining life of the Colstrip Regulatory Asset (approximately 28 years). This adjustment, therefore, reduces (credits) gross plant $84,447,000, reduces (debits) A/D $72,033,000, and

[51] This has the effect of removing 8 months in RY1, i.e., January 2026 – August 2026, of the September 2025 – August 2026 rate period.

increases the Colstrip Regulatory Asset $12,414,000 (net of gross plant and A/D). In addition, this adjustment removes from RY1, Colstrip depreciation expense included in current rates on existing pre-2018 investment, effective January 1, 2026 (or 8 months in RY1), reducing depreciation expense in RY1 by $1,963,000.

With the transfer of ownership, this results in unrecovered net plant (plant investment through December 31, 2017) as of December 31, 2025, of $5.9 million. Rather than recover this amount through depreciation expense January 1, 2026 through December 3, 2027, this unrecovered net plant investment is a portion of the amount moved to the Colstrip Regulatory Asset ($12.4 million) effective January 1, 2026, and amortized over the remaining 28 year amortization period, increasing amortization expense by $141,000 in RY1 (and an incremental amount of $70,000 in RY2, see Pro Forma Adjustment 26.10 below). The net effect, therefore, of this adjustment in RY1 to Idaho electric operations, results in an increase to regulatory amortization expense of $141,000, a reduction to depreciation expense of $1,963,000, and an increase to NOI of $1,439,000. This adjustment also decreases net plant by $12.4 million, offset by an increase to Deferred Debits (Colstrip Regulatory Asset) of $12.4 million, resulting in no ($0.0) impact to net rate base.

RY2 (09.2026 – 08.2027) – 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.

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, 2027 on an AMA basis and 3) property taxes on investment through 2026; 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; 7) IS/IT expense; and 8) miscellaneous O&M expense. The Company has also included the impact of 9) removing the remainder of Colstrip assets and depreciation expense, including adjusting EDIT for the removal of Colstrip, in RY2,[52] and 10) 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 (26.00P) – **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, 2026 through August 31, 2027, 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 (26.00P) represents the Idaho jurisdictional share of those amounts. The net effect of this adjustment decreases electric NOI by $7,512,000.[53]

Electric Adjustment (26.00T) – **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

[52] The removal of Colstrip effective January 1, 2026, has the effect of removing Colstrip balances for the period January – August 2026 in RY1 (8 months), and the remaining Colstrip balances, September – December 2026, in RY2 (4 months).

[53] See Pro Forma Adjustment 3.00P, which adjusts pro forma power supply amounts reflected in the 12ME June 30, 2024 test period, to reflect pro forma power supply amounts expected in RY1.

twelve-month period September 1, 2026 through August 31, 2027. The net effect of this adjustment increases electric NOI by $417,000.[54]

Electric Adjustment (26.01) and Natural Gas Adjustment (26.01) – **Pro Forma Capital Additions 08.2026 EOP**, as discussed and sponsored by Ms. Benjamin, reflects September 1, 2025 through August 31, 2026 capital additions[55] together with the associated A/D and ADFIT at an August 31, 2026 EOP basis. In addition, the plant-in-service at August 31, 2026 AMA was adjusted to an August 31, 2026 EOP basis. Since this adjustment is only pro forming the change from August 31, 2026 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. 3.09 – Pro Forma Capital Additions 08.2026 AMA. The impact of changing from AMA to EOP for depreciation expense on additions and retirements for the 12ME August 31, 2026 is picked up in the subsequent adjustment, Adj. 26.02 – Capital Additions 08.2027 AMA, described below. The net impact of this adjustment is an increase in total rate base of $26,122,000 electric and $630,000 natural gas. The net effect of this adjustment on NOI is an increase of $136,000 electric and $3,000 natural gas.

Electric Adjustment (26.02) and Natural Gas Adjustment (26.02) **Capital Additions 08.2027 AMA**, as discussed and sponsored by Ms. Benjamin, reflects September 1, 2026 through August 31, 2027 capital additions[56] together with the associated A/D and ADFIT at an August 31, 2027 AMA basis. This adjustment also includes associated depreciation

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[54] See Pro Forma Adjustment 3.00T, which adjusts pro forma transmission-related revenues and expenses reflected in the 12ME June 30, 2024 test period, to reflect pro forma transmission-related revenue/expense amounts expected in RY1.

[55] As noted previously, for the period July 1, 2024 through August 31, 2027, 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 also included as revenue offsets within Pro Forma Adjustments 3.10 (RY1) and 26.05 (RY2) "Pro Forma Revenue & O&M Offsets."

[56] *Ibid.*

expense for these additions. In addition, the plant-in-service at August 31, 2026 EOP was adjusted to an August 31, 2027 AMA basis. Finally, retirements for the twelve months-ended August 31, 2027 on an AMA basis on plant-in-service at August 31, 2026, were pro formed reducing depreciation expense, which was included in the overall impact of this adjustment. The net impact of this adjustment is an increase in total rate base of $47,450,000 for electric and $5,958,000 for natural gas. The net effect of this adjustment on NOI is a decrease of $1,729,000 for electric and $168,000 for natural gas.

Electric Adjustment (26.03) and Natural Gas Adjustment (26.03) – **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, 2025 (2026) and December 31, 2026 (2027) for the rate effective period (September 1, 2026 – August 31, 2027). The property tax balances include estimates for 2024-2026 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 $218,000 and natural gas NOI by $66,000.

Electric Adjustment (26.04) and Natural Gas Adjustment (26.04) – **Pro Forma Labor Non-Exec**, reflects incremental bargaining and non-bargaining wages and salaries from RY1 (included in Pro Forma Labor Non-Exec adjustment (3.01)) to RY2 (excludes executive salaries). For <u>non-bargaining</u> and <u>bargaining</u> employees, wages and salaries were adjusted to annualize (add 4 months) the estimated increase for 2026 effective March 1, 2026, for non-bargaining employees, and March 26, 2026, for bargaining employees, and a prorated amount (6 months non-bargaining, 5 months bargaining) of the estimated increase for 2027 effective March 1, 2027, for non-bargaining employees, and March 26, 2027, for bargaining employees.[57] The net effect of this adjustment on NOI is a decrease of $1,007,000 electric and $283,000 natural gas.

Electric Adjustment (26.05) and Natural Gas Adjustment (26.05) – **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. Howell, and Mr. Manuel, with the capital asset with which the net offset relates. The net effect of this adjustment increases Idaho NOI in RY2 by $1,429,000 for electric and by $590,000 for natural gas.

Electric Adjustment (26.06) and Natural Gas Adjustment (26.06) – **Pro Forma Miscellaneous O&M Expense**, as discussed and sponsored by Ms. Andrews, reflects escalated increases in certain (or subset of) Company O&M and A&G expenses, to reflect incremental expenses in RY2, beyond RY1 levels, effective September 1, 2026, through August 31, 2027, not otherwise pro formed within the Company's electric or natural gas Pro Forma Studies. The same escalation growth rate of 5.28% for electric and natural gas operations 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. This adjustment increases RY2 Idaho O&M expense by $1,560,000 for electric and $325,000 for natural gas and decreases Idaho NOI in RY2 by $1,232,000 for electric and $257,000 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.

[57] See CONFIDENTIAL 3.01 & 26.04 Non-Executive Labor Adjustment, Pro-Forma Increases tab for detailed, annualized Bargaining and Non-Bargaining labor increases by year.

A. The next adjustments on page 11 of Schedule 1 and Schedule 2 of Exhibit No. 4 include Electric Adjustment (26.07) and Natural Gas Adjustment (26.07) – **Pro Forma Employee Benefits.** This adjustment 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, 2026, through August 31, 2027. 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. 6 below:[58]

<u>Table No. 6: Benefit Adjustment for RY2</u>

Benefit Adjustment	RY2					
	System O&M		ID Electric		ID Natural Gas	
Medical	$	905,595	$	202,569	$	53,990
Retirement		518,539		115,990		30,914
Total	$	1,424,134	$	318,559	$	84,904

The net effect of this adjustment decreases RY2 Idaho NOI by $252,000 for electric and $67,000 for natural gas.

The next electric and last natural gas RY2 adjustment is Electric Adjustment (26.08) and Natural Gas Adjustment (26.08) – **Pro Forma IS/IT Expense**, as discussed and sponsored by Mr. Manuel. This adjustment adjusts the IS/IT expense level included in RY1 (included in Pro Forma IS/IT Costs adjustment (3.04)) to reflect incremental expected expense increases, mainly associated with general business systems, in the twelve-month period September 1, 2026 through August 31, 2027, above RY1 levels. This incremental increase reflects an expected increase in IS/IT expense above RY1 levels of approximately 1.9%

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

annually over the Two-Year Rate Plan. The effect of this adjustment decreases NOI by $72,000 for electric and by $21,000 for natural gas.[59]

Electric Adjustment (26.09) – **Pro Forma Colstrip/CS2 Maintenance,** as discussed and sponsored by Ms. Andrews, adjusts the Colstrip/CS2 Maintenance expense level included in RY1 (see Colstrip/CS2 Maintenance Adjustment (2.12)) to reflect the revised amortization expense for RY2. This adjustment adjusts RY1 amortization expense to a pro rata share of years 2026 and 2027 for RY2, which include one-third of each amount deferred (actual or estimated) for calendar years 2023 through 2025 and 2024 through 2026, respectively, increasing Idaho electric regulatory amortization expense by approximately $391,000.[60]

<u>In addition, in RY2</u>, Ms. Andrews also explains that in order to reflect the reduction in overall Colstrip and CS2 maintenance expense expected beginning in January 2027, mainly due to the transfer of plant ownership of Colstrip Units 3 and 4 to NorthWestern Energy at the end of 2025 as discussed by Mr. Kinney, the Company is including a reduction to O&M (maintenance) expense of approximately $1.9 million. <u>This adjustment reflects the Company's proposal to reduce the system authorized "Base O&M" expense level (for CS2 only) from $20,352,021 to $12,350,250, effective January 1, 2027</u>.[61 / 62] Therefore, the overall effect in RY2 of this adjustment (26.09) reduces net production O&M expense by $1,504,000

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[59] See Pro Forma Adjustment 3.04, which adjusts pro forma IS/IT expense amounts reflected in the 12ME June 30, 2024 test period, to reflect pro forma IS/IT expense amounts expected in RY1.

[60] See Restating Colstrip/CS2 Maintenance Adjustment 2.12, which adjusts Colstrip/CS2 maintenance amounts reflected in 12ME June 30, 2024 test year, to reflect the pro rata share of years 2022-2023 and estimated for 2024-2025, on a pro rata basis, including one-third of each amount deferred (actual or estimated) for calendar years 2022-2023, and 2024-2025, respectively, to reflect Colstrip/CS2 maintenance amounts expected in RY1.

[61] This has the effect of a split "O&M Baseline" of $15.08 million in RY2, reflecting 4 months (09.2026 – 12.2026) of authorized O&M Baseline of $20.4, plus 8 months (01.2027-8.2027) of the proposed O&M Baseline of $12.35 million. Idaho's share of this overall reduction is approximately $2.8 million beginning January 2027, or $1.9 million on a pro rata basis during RY2 (09.2026-8.2027).

[62] Although Colstrip Units 3 and 4 transfer ownership after 12.31.2025, reducing Colstrip maintenance expense, CS2 is expected to have its major overhaul in 2026, dependent on plant run-hours. Therefore, while the overall system O&M expense in 2025 (Colstrip & CS2) is expected at $22.8 million, the system O&M expense in 2026 (CS2 only) is expected at $28.1 million, and in 2027 (CS2 only), overall O&M finally drops to $12.35 million. Therefore, the Company proposes to revise the "O&M Baseline" effective January 1, 2027.

and increases NOI by $1,188,000.

Electric Adjustment (26.10) – **Pro Forma Colstrip Assets and Depreciation Removal (effective 01/01/2026),** as discussed and sponsored by Ms. Andrews, reflects the impact of removing the remaining net Colstrip investment (gross plant, offset by A/D) and depreciation expense (effective January 1, 2026)[63] from RY2 net plant, and recording (moving) the remaining unrecovered net plant balance for Colstrip assets at December 31, 2025, to the Colstrip Regulatory Asset, for amortization over the remaining life of the Colstrip Regulatory Asset (approximately 28 years). This adjustment, therefore, reduces (credits) gross plant $36,181,000, reduces (debits) A/D $30,413,000, and increases the Colstrip Regulatory Asset $5,768,000 (net of gross plant and A/D). In addition, this adjustment removes from RY2 the remaining Colstrip depreciation expense, not reduced in RY1, on existing pre-2018 investment, effective January 1, 2026 (or 4 months in RY2), reducing depreciation expense an incremental amount in RY2 of $982,000.

The net effect of this adjustment in RY2 to Idaho electric operations, results in an incremental increase to regulatory amortization expense of $70,000 (see Pro Forma Adjustment 3.16), a reduction to depreciation expense of $982,000, and an increase to NOI of $720,000. This adjustment also decreases net plant by $5.8 million, offset by an increase to Deferred Debits (Colstrip Regulatory Asset) of $5.8 million, resulting in no ($0.0) impact to net rate base.

The final RY2 electric adjustment, Electric Adjustment (26.11) – **Pro Forma EDIT (RSGM)**, adjusts the electric EDIT amortization expense included in RY1 (included in Pro Forma EDIT (RSGM) adjustment (3.07)) to reflect the level of EDIT amortization expense

[63] This has the effect of removing the remaining 4 months in RY2, i.e., September 2026 – December 2026, of the September 2026 – August 2027 rate period.

expected in the twelve-month period September 1, 2026 through August 31, 2027, incremental to RY1 levels. Although the RSGM is straight line, this adjustment is necessary to reflect the expected lower EDIT amortization expense in RY2, caused by the removal of the remaining four months (September 2026 through December 2026) of Colstrip investment in RY2. The effect of this adjustment decreases NOI by $120,000.[64]

<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 7.68% rate of return on a pro forma basis for the Two-Year Rate Plan?

A. For electric, the net operating income deficiency amounts to $33,784,000 for RY1 and $13,901,000 (incremental) for RY2, as shown on line 5, page 3 of Exhibit No. 4, Schedule 1. The resulting revenue requirement is shown on line 7 and amounts to $42,951,000 for RY1, or a base increase of 14.0% (14.4% billed), and $17,674,000 (incremental) for RY2, or a base increase of 5.0% (5.2% 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 7.68% 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 $6,924,000 for RY1 and $773,000 (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 $8,803,000 for RY1, or a base increase of 17.7% (10.3% billed), and $983,000 (incremental) for RY2, or a base increase of 1.7% (1.0% billed).

[64] See Pro Forma Adjustment 3.07, which adjusts pro forma EDIT amortization expense reflected in the 12ME June 30, 2024 test period, to reflect pro forma EDIT amortization expense expected in RY1.

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-23-01 and AVU-G-23-01, 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.

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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-25-01 CASE NO. AVU-G-25-01 EXHIBIT NO. 4 OF KAYLENE J. SCHULTZ

FOR AVISTA CORPORATION

(ELECTRIC AND NATURAL GAS)

AVISTA UTILITIES
IDAHO ELECTRIC RESULTS
TWELVE MONTHS ENDED JUNE 30, 2024
(000'S OF DOLLARS)

		09.2025 RY1				
		WITH PRESENT RATES			WITH 09.2025 PROPOSED RATES	
Line No.	DESCRIPTION	Actual Per Results Report	Total Adjustments	Pro Forma Total	Proposed Revenues & Related Exp	Pro Forma Proposed Total
	a	*b*	*c*	*d*	*e*	*f*
	REVENUES					
1	Total General Business	$316,228	($8,845)	$307,383	$42,951	$350,334
2	Interdepartmental Sales	268	-	268		268
3	Sales for Resale	95,125	(31,532)	63,593		63,593
4	Total Sales of Electricity	411,621	(40,377)	371,244	42,951	414,195
5	Other Revenue	32,122	(18,108)	14,014		14,014
6	Total Electric Revenue	443,743	(58,485)	385,258	42,951	428,209
	EXPENSES					
	Production and Transmission					
7	Operating Expenses	134,967	(41,475)	93,492		93,492
8	Purchased Power	97,850	(21,610)	76,240		76,240
9	Depreciation/Amortization	24,236	(173)	24,063		24,063
10	Regulatory Amortization	(8,130)	6,023	(2,107)		(2,107)
11	Taxes	6,355	113	6,468		6,468
12	Total Production & Transmission	255,278	(57,122)	198,156	-	198,156
	Distribution					
13	Operating Expenses	16,798	2,148	18,946		18,946
14	Depreciation/Amortization	19,624	1,169	20,793		20,793
15	Taxes	5,773	(3,529)	2,244		2,244
16	State Income Taxes	(20)	-	(20)	-	(20)
17	Total Distribution	42,175	(212)	41,963	-	41,963
18	Customer Accounting	4,471	331	4,802	95	4,897
19	Customer Service & Information	5,374	(4,815)	559		559
20	Sales Expenses	-	0	0		0
	Administrative & General					
21	Operating Expenses	39,899	6,842	46,741	91	46,832
22	Depreciation/Amortization	20,947	1,089	22,036		22,036
23	Regulatory Amortization	(845)	7,168	6,323		6,323
23	Taxes	1,937	-	1,937		1,937
24	Total Admin. & General	61,938	15,099	77,037	91	77,128
25	Total Electric Expenses	369,236	(46,719)	322,517	186	322,703
26	OPERATING INCOME BEFORE FIT	74,507	(11,766)	62,741	42,765	105,506
	FEDERAN INCOME TAX					
27	Current Accrual	4,820	(5,708)	(888)	8,981	8,093
28	Debt Interest	-	(626)	(626)		(626)
29	Deferred Income Taxes	(3,645)	9,532	5,887		5,887
30	Amortized Investment Tax Credit	(213)	-	(213)		(213)
31	NET OPERATING INCOME	$73,545	($14,963)	$58,582	$33,784	$92,366
	RATE BASE					
	PLANT IN SERVICE					
32	Intangible	$113,194	$3,542	$116,736		$116,736
33	Production	565,583	(51,838)	513,745		513,745
34	Transmission	373,695	28,532	402,227		402,227
35	Distribution	798,903	122,766	921,669		921,669
36	General	149,447	15,872	165,319		165,319
37	Total Plant in Service	2,000,822	118,874	2,119,696	-	2,119,696
	ACCUMULATED DEPRECIATION					
38	Intangible	(51,359)	(9,573)	(60,932)		(60,932)
39	Production	(265,055)	46,228	(218,827)		(218,827)
40	Transmission	(102,512)	(15,347)	(117,859)		(117,859)
41	Distribution	(295,777)	(25,057)	(320,834)		(320,834)
42	General	(56,384)	(5,532)	(61,916)		(61,916)
43	Total Accumulated Depreciation	(771,087)	(9,281)	(780,368)	-	(780,368)
44	NET PLANT BEFORE DFIT	1,229,735	109,593	1,339,328	-	1,339,328
45	DEFERRED TAXES	(199,052)	(795)	(199,847)		(199,847)
46	NET PLANT AFTER DFIT	1,030,683	108,798	1,139,481	-	1,139,481
47	DEFERRED DEBITS AND CREDITS	11,797	12,417	24,214		24,214
48	WORKING CAPITAL	39,905	(923)	38,982		38,982
49	TOTAL RATE BASE	$1,082,385	$120,292	$1,202,677	$0	$1,202,677
50	RATE OF RETURN	6.79%		4.87%		7.68%

AVISTA UTILITIES
IDAHO ELECTRIC RESULTS
TWELVE MONTHS ENDED JUNE 30, 2024
(000'S OF DOLLARS)

		09.2026 RY2					
		WITH 09.2025 PROPOSED RATES				WITH 09.2026 PROPOSED RATES	
Line No.	DESCRIPTION	09.2025 Pro Forma Total	09.2026 Total Adjustments	09.2026 Pro Forma Total	09.2025 Proposed Revenues & Related Exp	09.2026 Proposed Revenues & Related Exp	09.2026 Pro Forma Proposed Total
	a	*b*	*c*	*d*	*e*	*f*	*g*
	REVENUES						
1	Total General Business	$307,383	$0	$307,383	$42,951	$17,674	$368,008
2	Interdepartmental Sales	268	-	268			268
3	Sales for Resale	63,593	279	63,872			63,872
4	Total Sales of Electricity	371,244	279	$371,523	42,951	17,674	432,148
5	Other Revenue	14,014	2,026	16,040			16,040
6	Total Electric Revenue	385,258	2,305	387,563	42,951	17,674	448,188
	EXPENSES						
	Production and Transmission						
7	Operating Expenses	93,492	2,792	96,284			96,284
8	Purchased Power	76,240	6,165	82,405			82,405
9	Depreciation/Amortization	24,063	(72)	23,991			23,991
10	Regulatory Amortization	(2,107)	391	(1,716)			(1,716)
11	Taxes	6,468	218	6,686			6,686
12	Total Production & Transmission	198,156	9,494	207,650	-	-	207,650
	Distribution						
13	Operating Expenses	18,946	604	19,550			19,550
14	Depreciation/Amortization	20,793	1,469	22,262			22,262
15	Taxes	2,244	58	2,302			2,302
16	State Income Taxes	(20)	-	(20)	-	-	(20)
17	Total Distribution	41,963	2,131	44,094	-	-	44,094
18	Customer Accounting	4,802	193	4,995	95	39	5,129
19	Customer Service & Information	559	26	585			585
20	Sales Expenses	-	0	0			0
	Administrative & General						
21	Operating Expenses	46,741	1,047	47,788	91	38	47,917
22	Depreciation/Amortization	22,036	122	22,158			22,158
22	Regulatory Amortization	6,323	70	6,393			6,393
23	Taxes	1,937	-	1,937			1,937
24	Total Admin. & General	77,037	1,239	78,276	91	38	78,405
25	Total Electric Expenses	322,517	13,083	335,600	186	77	335,863
26	OPERATING INCOME BEFORE FIT	62,741	(10,778)	51,963	42,765	17,597	112,325
	FEDERAL INCOME TAX						
27	Current Accrual	(888)	(2,263)	(3,151)	8,981	3,695	9,525
28	Debt Interest	(626)	(383)	(1,010)			(1,010)
29	Deferred Income Taxes	5,887	120	6,007			6,007
30	Amortized Investment Tax Credit	(213)	-	(213)			(213)
31	NET OPERATING INCOME	$58,582	($8,251)	$50,331	$33,784	$13,902	$98,016
	RATE BASE						
	PLANT IN SERVICE						
32	Intangible	$116,736	$1,998	$118,734			$118,734
33	Production	513,745	(14,188)	499,557			499,557
34	Transmission	402,227	14,209	416,436			416,436
35	Distribution	921,669	65,117	986,786			986,786
36	General	165,319	5,493	170,812			170,812
37	Total Plant in Service	2,119,696	72,629	2,192,325	-	-	2,192,325
	ACCUMULATED DEPRECIATION						
38	Intangible	(60,932)	408	(60,524)			(60,524)
39	Production	(218,827)	20,943	(197,884)			(197,884)
40	Transmission	(117,859)	(8,253)	(126,112)			(126,112)
41	Distribution	(320,834)	(7,438)	(328,272)			(328,272)
42	General	(61,916)	(5,394)	(67,310)			(67,310)
43	Total Accumulated Depreciation	(780,368)	266	(780,102)	-	-	(780,102)
44	NET PLANT BEFORE DFIT	1,339,328	72,895	1,412,223	-	-	1,412,223
45	DEFERRED TAXES	(199,847)	(5,091)	(204,938)			(204,938)
46	NET PLANT AFTER DFIT	1,139,481	67,804	1,207,285	-	-	1,207,285
47	DEFERRED DEBITS AND CREDITS	24,214	5,768	29,982			29,982
48	WORKING CAPITAL	38,982	-	38,982			38,982
49	TOTAL RATE BASE	$1,202,677	73,572	$1,276,249	$0	$0	$1,276,249
50	RATE OF RETURN	4.87%		3.94%			7.68%

AVISTA UTILITIES
Calculation of General Revenue Requirement
Idaho - Electric System
TWELVE MONTHS ENDED JUNE 30, 2024

Line No.	Description	RY1 Sep-25 (000's of Dollars)	RY2 Sep-26 (000's of Dollars)	Incremental RY2 Sep-26 (000's of Dollars)
1	Pro Forma Rate Base	$1,202,677	$1,276,249	
2	Proposed Rate of Return	7.68%	7.68%	
3	Net Operating Income Requirement	$92,366	$98,016	
4	Pro Forma Net Operating Income	$58,582	$50,331	
5	Net Operating Income Deficiency	$33,784	$47,685	$13,901
6	Conversion Factor	0.78657	0.78657	0.78657
7	Revenue Requirement	**$42,951**	$60,624	**$17,674**
8	Total General Business Revenues	$307,651		$350,602
9	Percentage Revenue Increase - Base	**13.96%**		**5.04%**
10	Total Billed Revenues	$297,466		$340,417
11	Percentage Revenue Increase -Billed	14.44%		5.19%

AVISTA UTILITIES
Pro Forma Cost of Capital
Idaho - Electric System

Proposed:

Component	Capital Structure	Pro Forma Cost	Pro Forma Weighted Cost
Total Debt	50.00%	4.95%	2.48%
Common	50.00%	10.40%	5.20%
Total	100.00%		7.68%

AVISTA UTILITIES
Revenue Conversion Factor
Idaho - Electric System
TWELVE MONTHS ENDED JUNE 30, 2024

Line No.		Description	Factor
1		**Revenues**	1.000000
		Expenses:	
2		Uncollectibles	0.002212
3		Commission Fees	0.002127
4		Idaho Income Tax	0.000000
5		Total Expenses	0.004339
6		Net Operating Income Before FIT	0.995661
7	21%	Federal Income Tax @ 21%	0.209089
8		**REVENUE CONVERSION FACTOR**	0.786572

Rate Year September 1, 2025 - August 31, 2026

Line No.	DESCRIPTION	Results of Operations	Accumulated Deferred FIT Rate Base	Deferred Debits, Credits & Reg Amortizations	Working Capital	Restate Capital 06.2024 EOP	Eliminate B & O Taxes	Uncollectible Expense	Regulatory Expense	Injuries and Damages	FIT/DFIT ITC/PTC Expense
	Adjustment Number	**1.00**	**1.01**	**1.02**	**1.03**	**1.04**	**2.01**	**2.02**	**2.03**	**2.04**	**2.05**
	Workpaper Reference	**E-ROO**	**E-ADFIT**	**E-DDC**	**E-WC**	**E-RCAP**	**E-EBO**	**E-UE**	**E-RE**	**E-ID**	**E-FIT**
	REVENUES										
1	Total General Business	$316,228	$0	$0	$0	$0	($4,128)	$0	$0	$0	$0
2	Interdepartmental Sales	268	-	0	-	-	-	0	0	0	0
3	Sales for Resale	95,125	-	0	-	-	-	0	0	0	0
4	Total Sales of Electricity	411,621	0	0	0	0	(4,128)	0	0	0	0
5	Other Revenue	32,122	-	0	-	-	-	0	0	0	0
6	Total Electric Revenue	443,743	0	0	0	0	(4,128)	0	0	0	0
	EXPENSES										
	Production and Transmission										
7	Operating Expenses	134,967	-	165	-	-	-	0	0	0	0
8	Purchased Power	97,850	-	0	-	-	-	0	0	0	0
9	Depreciation/Amortization	24,236	-	0	-	-	-	0	0	0	0
10	Regulatory Amortization	(8,130)	-	(291)	-	-	-	0	0	0	0
11	Taxes	6,355	-	0	-	-	-	0	0	0	0
12	Total Production & Transmission	255,278	0	(126)	0	0	0	0	0	0	0
	Distribution										
13	Operating Expenses	16,798	-	0	-	-	-	0	0	0	0
14	Depreciation/Amortization	19,624	-	0	-	-	-	0	0	0	0
15	Taxes	5,773	-	0	-	-	(4,128)	0	0	0	0
16	State Income Taxes **0.000000**	(20)	-	0	0	0	0	0	0	0	0
17	Total Distribution	42,175	0	0	0	0	(4,128)	0	0	0	0
18	Customer Accounting	4,471	-	0	-	-	-	(189)	0	0	0
19	Customer Service & Information	5,374	-	0	-	-	-	0	0	0	0
20	Sales Expenses	0	-	0	-	-	-	0	0	0	0
	Administrative & General										
21	Operating Expenses	39,899	-	-	-	-	-	-	104	(176)	-
22	Depreciation/Amortization	20,947	-	-	-	-	-	-	-	-	-
23	Regulatory Amortization	(845)	-	(128)	-	-	-	-	-	-	-
24	Taxes	1,937	-	-	-	-	-	-	-	-	-
25	Total Admin. & General	61,938	0	(128)	0	0	0	0	104	(176)	0
26	Total Electric Expenses	369,236	0	(254)	0	0	(4,128)	(189)	104	(176)	0
27	OPERATING INCOME BEFORE FIT	74,507	0	254	0	0	0	189	(104)	176	0
	FEDERAL INCOME TAX										
28	Current Accrual	4,820	-	53	-	-	-	40	(22)	37	-
29	Debt Interest	0	(16)	(0)	5	(144)	-	-	-	-	-
30	Deferred Income Taxes	(3,645)	-	671	-	-	-	0	0	0	0
31	Amortized ITC	(213)	-	0	-	-	-	0	0	0	0
32	NET OPERATING INCOME	$73,545	$16	($470)	($5)	$144	$0	$149	($82)	$139	$0
	RATE BASE										
	PLANT IN SERVICE										
33	Intangible	$113,194	$0	$0	$0	$4,607	$0	$0	$0	$0	$0
34	Production	565,583	-	0	-	3,404	-	0	0	0	0
35	Transmission	373,695	-	0	-	6,724	-	0	0	0	0
36	Distribution	798,903	-	0	-	31,990	-	0	0	0	0
37	General	149,447	-	0	-	749	-	0	0	0	0
38	Total Plant in Service	2,000,822	-	-	-	47,474	-	-	-	-	-
	ACCUMULATED DEPRECIATION/AMORT										
39	Intangible	(51,359)	-	0	-	(5,366)	-	0	0	0	0
40	Production	(265,055)	-	0	-	(6,039)	-	0	0	0	0
41	Transmission	(102,512)	-	0	-	(1,980)	-	0	0	0	0
42	Distribution	(295,777)	-	0	-	(8,283)	-	0	0	0	0
43	General	(56,384)	-	0	-	1,497	-	0	0	0	0
44	Total Accumulated Depreciation	(771,087)	-	-	-	(20,171)	-	-	-	-	-
45	NET PLANT	1,229,735	-	-	-	27,303	-	-	-	-	-
46	DEFERRED TAXES	(199,052)	3,022	-	-	427	-	-	-	-	-
47	Net Plant After DFIT	1,030,683	3,022	-	-	27,730	-	-	-	-	-
48	DEFERRED DEBITS AND CREDITS	11,797	-	3	-		-	-	-	-	-
49	WORKING CAPITAL	39,905	-	-	(923)	-	-	-	-	-	-
50	TOTAL RATE BASE	$1,082,385	$3,022	$3	(923)	27,730	-	$0	$0	$0	$0
51	RATE OF RETURN	**6.79%**	0								
52	REVENUE REQUIREMENT	12,182	275	598	(84)	2,524	-	(190)	105	(177)	-

AVISTA UTILITIES
IDAHO ELECTRIC RESULTS
TWELVE MONTHS ENDED JUNE 30, 2024
(000'S OF DOLLARS)

Line No.	DESCRIPTION	SIT/SITC Expense	Revenue Normalization	Miscellaneous Restating	Restate Incentives	ID PCA	Nez Perce Settlement Adjustment	Colstrip / CS2 Maintenance	Restate Debt Interest	Restated TOTAL
	Adjustment Number	2.06	2.07	2.08	2.09	2.10	2.11	2.12	2.13	R-Ttl
	Workpaper Reference	E-SIT	E-RN	E-MR	E-RI	E-PCA	E-NPS	E-CCOM	E-RDI	
	REVENUES									
1	Total General Business	$0	$7,685	$0	$0	($12,402)	$0	$0	$0	$307,383
2	Interdepartmental Sales	0	-	0	-	-	0	0	0	268
3	Sales for Resale	0	-	0	-	-	0	0	0	95,125
4	Total Sales of Electricity	0	7,685	0	0	(12,402)	0	0	0	402,776
5	Other Revenue	0	(5,466)	(916)	-	-	0	0	0	25,740
6	Total Electric Revenue	0	2,219	(916)	0	(12,402)	0	0	0	428,516
	EXPENSES									
	Production and Transmission									
7	Operating Expenses	0	(374)	0	-	(20,004)	(25)	0	0	114,729
8	Purchased Power	0	(12,902)	0	-	-	0	0	0	84,948
9	Depreciation/Amortization	0	-	0	-	-	0	0	0	24,236
10	Regulatory Amortization	0	4,944	0	-	-	0	1,083	0	(2,394)
11	Taxes	0	-	0	-	-	0	0	0	6,355
12	Total Production & Transmission	0	(8,332)	0	0	(20,004)	(25)	1,083	0	227,874
	Distribution									
13	Operating Expenses	0	-	11	-	-	0	0	0	16,809
14	Depreciation/Amortization	0	-	0	-	-	0	0	0	19,624
15	Taxes	0	-	0	-	-	0	0	0	1,645
16	State Income Taxes	0	-	0	0	-	0	0	-	(20)
17	Total Distribution	0	0	11	0	0	0	0	0	38,058
18	Customer Accounting	0	46	15	-	(22)	0	0	0	4,321
19	Customer Service & Information	0	(4,871)	0	-	-	0	0	0	503
20	Sales Expenses	0	-	0	-	-	0	0	0	-
	Administrative & General									
21	Operating Expenses	-	16	(11)	477	(25)	0	0	0	40,285
22	Depreciation/Amortization	-	-	0	-	-	0	0	0	20,947
23	Regulatory Amortization	-	286	0	-	-	0	0	0	(687)
24	Taxes	-	-	0	-	-	0	0	0	1,937
25	Total Admin. & General	0	302	(11)	477	(25)	0	0	0	62,482
26	Total Electric Expenses	0	(12,855)	15	477	(20,051)	(25)	1,083	0	333,238
27	OPERATING INCOME BEFORE FIT	0	15,074	(931)	(477)	7,649	25	(1,083)	0	95,278
	FEDERAL INCOME TAX									
28	Current Accrual	-	3,165	(196)	(100)	(2,595)	5	(227)	964	5,945
29	Debt Interest	-	-	-	-	-	-	-		(155)
30	Deferred Income Taxes	0	4,303	0	-	4,201	0	0	0	5,530
31	Amortized ITC	0	-	0	-	-	0	0	0	(213)
32	NET OPERATING INCOME	$0	$7,605	($736)	($377)	$6,043	$20	($856)	($964)	84,172
	RATE BASE									
	PLANT IN SERVICE									
33	Intangible	$0	$0	$0	$0	$0	$0	$0	$0	$ 117,801
34	Production	0	-	0	-	-	0	0	0	568,987
35	Transmission	0	-	0	-	-	0	0	0	380,419
36	Distribution	0	-	0	-	-	0	0	0	830,893
37	General	0	-	0	-	-	0	0	0	150,196
38	Total Plant in Service	-	-	-	-	-	-	-	-	2,048,296
	ACCUMULATED DEPRECIATION/AM									
39	Intangible	0	-	0	-	-	0	0	0	(56,725)
40	Production	0	-	0	-	-	0	0	0	(271,094)
41	Transmission	0	-	0	-	-	0	0	0	(104,492)
42	Distribution	0	-	0	-	-	0	0	0	(304,060)
43	General	0	-	0	-	-	0	0	0	(54,887)
44	Total Accumulated Depreciation	-	-	-	-	-	-	-	-	(791,258)
45	NET PLANT	-	-	-	-	-	-	-	-	1,257,038
46	DEFERRED TAXES	-	-	-	-	-	-	-	-	(195,603)
47	Net Plant After DFIT	-	-	-	-	-	-	-	-	1,061,435
48	DEFERRED DEBITS AND CREDITS	-	-	-	-	-	-	-	-	11,800
49	WORKING CAPITAL	-	-	-	-	-	-	-	-	38,982
50	TOTAL RATE BASE	$0	$0	$0	$0	$0	$0	$0	$0	$1,112,217
51	RATE OF RETURN									7.57%
52	REVENUE REQUIREMENT	-	(9,669)	935	479	(7,683)	(25)	1,088	1,226	1,584

AVISTA UTILITIES
IDAHO ELECTRIC RESULTS
TWELVE MONTHS ENDED JUNE 30, 2024
(000'S OF DOLLARS)

Line No.	DESCRIPTION	Pro Forma Power Supply	Pro Forma Transmission Rev/Exp	Pro Forma Labor Non-Exec	Pro Forma Labor Exec	Pro Forma Employee Benefits	Pro Forma IS/IT Costs	Pro Forma Property Tax	Pro Forma Insurance Expense	Pro Forma EDIT (RSGM)	Planned Capital Add 08.2025 EOP	Planned Capital Add 08.2026 AMA
	Adjustment Number	**3.00P**	**3.00T**	**3.01**	**3.02**	**3.03**	**3.04**	**3.05**	**3.06**	**3.07**	**3.08**	**3.09**
	Workpaper Reference	**E-PPS25**	**E-PTR25**	**E-PLN**	**E-PLE**	**E-PEB25**	**E-ISIT**	**E-PPT**	**E-PIns**	**E-EDIT**	**E-CAP25E**	**E-CAP26A**
	REVENUES											
1	Total General Business	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2	Interdepartmental Sales	-	-	-	-	-	0	0	-	-	-	-
3	Sales for Resale	(31,532)	-	-	-	-	0	0	-	-	-	-
4	Total Sales of Electricity	(31,532)	0	0	0	0	0	0	0	0	0	0
5	Other Revenue	(15,082)	60	-	-	-	0	0	-	-	-	-
6	Total Electric Revenue	(46,614)	60	0	0	0	0	0	0	0	0	0
	EXPENSES											
	Production and Transmission											
7	Operating Expenses	(24,565)	-	1,252	-	489	0	0	-	-	-	-
8	Purchased Power	(8,708)	-	-	-	-	0	0	-	-	-	-
9	Depreciation/Amortization	-	-	-	-	-	0	0	-	-	1,191	599
10	Regulatory Amortization						0	0	-	-		
11	Taxes	-	-	-	-	-	0	113	-	-	-	-
12	Total Production & Transmission	(33,273)	0	1,252	0	489	0	113	0	0	1,191	599
	Distribution											
13	Operating Expenses	-	-	636		244	0	0	-	-	-	-
14	Depreciation/Amortization	-	-	-	-	-	0	0	-	-	(136)	1,305
15	Taxes	-	-	-	-	-	0	599	-	-	-	-
16	State Income Taxes	0	0	0	0	0	0	0	-	-	-	-
17	Total Distribution	0	0	636	0	244	0	599	0	0	(136)	1,305
18	Customer Accounting	-	-	231	-	85	0	0	-	-	-	-
19	Customer Service & Information	-	-	14	-	-	0	0	-	-	-	-
20	Sales Expenses	-	-	0	-	-	0	0	-	-	-	-
	Administrative & General											
21	Operating Expenses	-	-	1,054	(68)	403	254	0	4,065	-	-	-
22	Depreciation/Amortization	-	-	-	-	-	0	0	-	-	1,199	(110)
23	Regulatory Amortization	-	-	-	-	-	0	0	1,874		-	-
24	Taxes	-	-	-	-	-	0	0	-	-	-	-
25	Total Admin. & General	0	0	1,054	(68)	403	254	0	5,939	0	1,199	(110)
26	Total Electric Expenses	(33,273)	0	3,187	(68)	1,221	254	712	5,939	0	2,254	1,794
27	OPERATING INCOME BEFORE FIT	(13,341)	60	(3,187)	68	(1,221)	(254)	(712)	(5,939)	0	(2,254)	(1,794)
	FEDERAL INCOME TAX											
28	Current Accrual	(2,802)	13	(669)	14	(256)	(53)	(150)	(1,247)	-	(473)	(377)
29	Debt Interest	-	-	-	-	-	-	-	-	-	(268)	(178)
30	Deferred Income Taxes	-	-	-	-	-	0	0	-	357	-	-
31	Amortized ITC	-	-	-	-	-	0	0	-	-	-	-
32	NET OPERATING INCOME	($10,539)	$47	($2,518)	$54	($965)	($201)	($562)	($4,692)	($357)	($1,512)	($1,239)
	RATE BASE											
	PLANT IN SERVICE											
33	Intangible	$0	$0	$0	$0	$0	$0	$0	$0	$0	($962)	($103)
34	Production	-	-	-	-	-	0	0	-	-	18,962	5,450
35	Transmission	-	-	-	-	-	0	0	-	-	16,399	5,409
36	Distribution	-	-	-	-	-	0	0	-	-	57,716	33,060
37	General	-	-	-	-	-	0	0	-	-	11,099	4,024
38	Total Plant in Service	-	-	-	-	-	-	-	-	-	103,214	47,840
	ACCUMULATED DEPRECIATION/AM	-	-	-	-	-						
39	Intangible	-	-	-	-	-	0	0	-	-	(1,954)	(2,253)
40	Production	-	-	-	-	-	0	0	-	-	(15,188)	(4,578)
41	Transmission	-	-	-	-	-	0	0	-	-	(9,273)	(4,094)
42	Distribution	-	-	-	-	-	0	0	-	-	(18,301)	1,527
43	General	-	-	-	-	-	0	0	-	-	(5,041)	(1,988)
44	Total Accumulated Depreciation	-	-	-	-	-	-	-	-	-	(49,757)	(11,386)
45	NET PLANT	-	-	-	-	-	-	-	-	-	53,457	36,454
46	DEFERRED TAXES	-	-	-	-	-	-	-	-	-	(1,946)	(2,298)
47	Net Plant After DFIT	-	-	-	-	-	-	-	-	-	51,511	34,156
48	DEFERRED DEBITS AND CREDITS	-	-	-	-	-	-	-	-	-	-	-
49	WORKING CAPITAL	-	-	-	-	-	-	-	-	-	-	-
50	TOTAL RATE BASE	$0	$0	$0	$0	$0	$0	$0	-	-	51,511	34,156
51	RATE OF RETURN											
52	REVENUE REQUIREMENT	13,399	(60)	3,201	(68)	1,226	255	715	5,965	454	6,952	4,911

AVISTA UTILITIES
IDAHO ELECTRIC RESULTS
TWELVE MONTHS ENDED JUNE 30, 2024
(000'S OF DOLLARS)

Line No.	DESCRIPTION	Pro Forma Revenue & O&M Offsets	Pro Forma Regulatory Amortizations	Pro Forma Misc. O&M Expense	Pro Forma Locates Expense	Pro Forma Wildfire Plan Expenses	Pro Forma Colstrip Regulatory Asset Additions & Amortization	Pro Forma Colstrip - Adjust Assets Depr. 1/1/2026 (8 mos.)	RY1 09.2025 FINAL TOTAL
	Adjustment Number	**3.10**	**3.11**	**3.12**	**3.13**	**3.14**	**3.15**	**3.16**	**F-Ttl**
	Workpaper Reference	**E-POFF25**	**E-PRA**	**E-PME25**	**E-LOC**	**E-PWF**	**E-Cols25**	**E-ColsR**	
	REVENUES								
1	Total General Business	$0	$0	$0	$0	$0	$0	$0	$307,383
2	Interdepartmental Sales	-	-	-	-	-	-	-	268
3	Sales for Resale	-	-	-	-	-	-	-	63,593
4	Total Sales of Electricity	0	0	0	0	0	0	0	371,244
5	Other Revenue	3,296	-	-	-	-	-	-	14,014
6	Total Electric Revenue	3,296	0	0	0	0	0	0	385,258
	EXPENSES								
	Production and Transmission								
7	Operating Expenses	(77)	-	1,474	-	190	-	-	93,492
8	Purchased Power	-	-	-	-	-	-	-	76,240
9	Depreciation/Amortization	-	-	-	-	-	-	(1,963)	24,063
10	Regulatory Amortization	-	287	-	-	-	-	-	(2,107)
11	Taxes	-	-	-	-	-	-	-	6,468
12	Total Production & Transmission	(77)	287	1,474	0	190	0	(1,963)	198,156
	Distribution								
13	Operating Expenses	(142)	-	705	299	395	-	-	18,946
14	Depreciation/Amortization	-	-	-	-	-	-	-	20,793
15	Taxes	-	-	-	-	-	-	-	2,244
16	State Income Taxes	-	-	-	-	-	-	-	(20)
17	Total Distribution	(142)	0	705	299	395	0	0	41,963
18	Customer Accounting	-	-	165	-	-	-	-	4,802
19	Customer Service & Information	-	-	42	-	-	-	-	559
20	Sales Expenses	-	-	-	-	-	-	-	0
	Administrative & General								
21	Operating Expenses	(250)	-	998	-	-	-	-	46,741
22	Depreciation/Amortization	-	-	-	-	-	-	-	22,036
23	Regulatory Amortization	-	3,585	-	-	1,189	221	141	6,323
24	Taxes	-	-	-	-	-	-	-	1,937
25	Total Admin. & General	(250)	3,585	998	0	1,189	221	141	77,037
26	Total Electric Expenses	(469)	3,872	3,384	299	1,774	221	(1,822)	322,517
27	OPERATING INCOME BEFORE FIT	3,765	(3,872)	(3,384)	(299)	(1,774)	(221)	1,822	62,741
	FEDERAL INCOME TAX								
28	Current Accrual	791	(813)	(711)	(63)	(373)	(46)	383	(888)
29	Debt Interest	-	-	-	-	-	(25)	-	(626)
30	Deferred Income Taxes	-	-	-	-	-	-	-	5,887
31	Amortized ITC	-	-	-	-	-	-	-	(213)
32	NET OPERATING INCOME	$2,974	($3,059)	($2,673)	($236)	($1,401)	($150)	$1,439	$58,582
	RATE BASE								
	PLANT IN SERVICE								
33	Intangible	$0	$0	$0	$0	$0	$0	$0	$ 116,736
34	Production	-	-	-	-	-	4,793	(84,447)	513,745
35	Transmission	-	-	-	-	-	-	-	402,227
36	Distribution	-	-	-	-	-	-	-	921,669
37	General	-	-	-	-	-	-	-	165,319
38	Total Plant in Service	-	-	-	-	-	4,793	(84,447)	2,119,696
	ACCUMULATED DEPRECIATION/AM								
39	Intangible	-	-	-	-	-	-	-	(60,932)
40	Production	-	-	-	-	-	-	72,033	(218,827)
41	Transmission	-	-	-	-	-	-	-	(117,859)
42	Distribution	-	-	-	-	-	-	-	(320,834)
43	General	-	-	-	-	-	-	-	(61,916)
44	Total Accumulated Depreciation	-	-	-	-	-	-	72,033	(780,368)
45	NET PLANT	-	-	-	-	-	4,793	(12,414)	1,339,328
46	DEFERRED TAXES	-	-		-	-	-	-	(199,847)
47	Net Plant After DFIT	-	-	-	-	-	4,793	(12,414)	1,139,481
48	DEFERRED DEBITS AND CREDITS	-	-	-	-	-	-	12,414	24,214
49	WORKING CAPITAL	-	-	-	-	-	-	-	38,982
50	TOTAL RATE BASE	-	-	-	-	-	4,793	-	$1,202,677
51	RATE OF RETURN								**4.87%**
52	REVENUE REQUIREMENT	(3,781)	3,889	3,399	300	1,782	658	(1,830)	**42,951**

AVISTA UTILITIES **Rate Year September 1, 2026 - August 31, 2027**
IDAHO ELECTRIC RESULTS
TWELVE MONTHS ENDED JUNE 30, 2024
(000'S OF DOLLARS)

Line No.	DESCRIPTION	09.2025 FINAL TOTAL	Pro Forma Power Supply	Pro Forma Transmission Rev/Exp	Planned Capital Add 08.2026 EOP	Planned Capital Add 08.2027 AMA	Pro Forma Property Tax	Pro Forma Labor Non-Exec	Pro Forma Revenue & O&M Offsets	Pro Forma Misc. O&M Expense
	Adjustment Number	F-Ttl	26.00P	26.00T	26.01	26.02	26.03	26.04	26.05	26.06
	Workpaper Reference		E-PPS26	E-PTR26	E-CAP26E	E-CAP27A	E-PPT26	E-PLN26	E-POFF26	E-PME26
	REVENUES									
1	Total General Business	$307,383	$0	$0	$0	$0	$0	$0	$0	$0
2	Interdepartmental Sales	268	0	0	-	-	0	0	0	0
3	Sales for Resale	63,593	279	0	-	-	0	0	0	0
4	Total Sales of Electricity	371,244	279	0	0	0	0	0	0	0
5	Other Revenue	14,014	(218)	528	-	-	0	0	1,716	0
6	Total Electric Revenue	385,258	61	528	0	0	0	0	1,716	0
	EXPENSES									
	Production and Transmission									
7	Operating Expenses	93,492	3,405	0	-	-	0	492	(17)	679
8	Purchased Power	76,240	6,165	0	-	-	0	0	0	0
9	Depreciation/Amortization	24,063	0	0	-	910	0	0	0	0
10	Regulatory Amortization	(2,107)	0	0	-	-	0	0	0	0
11	Taxes	6,468	0	0	-	-	218	0	0	0
12	Total Production & Transmission	198,156	9,570	0	0	910	218	492	(17)	679
	Distribution									
13	Operating Expenses	18,946	0	0	-	-	0	246	(31)	325
14	Depreciation/Amortization	20,793	0	0	-	1,469	0	0	0	0
15	Taxes	2,244	0	0	-	-	58	0	0	0
16	State Income Taxes	(20)	0	0	-	-	0	0	0	0
17	Total Distribution	41,963	0	0	0	1,469	58	246	(31)	325
18	Customer Accounting	4,802	0	0	-	-	0	95	0	76
19	Customer Service & Information	559	0	0	-	-	0	6	0	20
20	Sales Expenses	0	0	0	-	-	0	0	0	0
	Administrative & General									
21	Operating Expenses	46,741	0	0	-	-	0	436	(45)	460
22	Depreciation/Amortization	22,036	0	0	-	122	0	0	0	0
23	Regulatory Amortization	6,323	0	0	-	-	0	0	0	0
24	Taxes	1,937	0	0	-	-	0	0	0	0
25	Total Admin. & General	77,037	0	0	0	122	0	436	(45)	460
26	Total Electric Expenses	322,517	9,570	0	0	2,501	276	1,275	(93)	1,560
27	OPERATING INCOME BEFORE FIT	62,741	(9,509)	528	0	(2,501)	(276)	(1,275)	1,809	(1,560)
	FEDERAL INCOME TAX									
28	Current Accrual	(888)	(1,997)	111	-	(525)	(58)	(268)	380	(328)
29	Debt Interest	(626)	-	-	(136)	(247)	-	-	-	-
30	Deferred Income Taxes	5,887	0	0	-	-	0	0	0	0
31	Amortized ITC	(213)	0	0	-	-	0	0	0	0
32	NET OPERATING INCOME	$58,582	($7,512)	$417	$136	($1,729)	($218)	($1,007)	$1,429	($1,232)
	RATE BASE									
	PLANT IN SERVICE									
33	Intangible	116,736	$0	$0	($1,581)	$3,579	$0	$0	$0	$0
34	Production	513,745	0	0	12,791	9,202	0	0	0	0
35	Transmission	402,227	0	0	3,543	10,666	0	0	0	0
36	Distribution	921,669	0	0	32,969	32,148	0	0	0	0
37	General	165,319	0	0	3,110	2,383	0	0	0	0
38	Total Plant in Service	2,119,696	-	-	50,832	57,978	-	-	-	-
	ACCUMULATED DEPRECIATION/AM							-		
39	Intangible	(60,932)	0	0	(220)	628	0	0	0	0
40	Production	(218,827)	0	0	(5,169)	(4,301)	0	0	0	0
41	Transmission	(117,859)	0	0	(4,416)	(3,837)	0	0	0	0
42	Distribution	(320,834)	0	0	(8,102)	664	0	0	0	0
43	General	(61,916)	0	0	(4,017)	(1,377)	0	0	0	0
44	Total Accumulated Depreciation	(780,368)	-	-	(21,924)	(8,223)	-	-	-	-
45	NET PLANT	1,339,328	-	-	28,908	49,755	-	-	-	-
46	DEFERRED TAXES	(199,847)	-	-	(2,786)	(2,305)	-	-	-	-
47	Net Plant After DFIT	1,139,481	-	-	26,122	47,450	-	-	-	-
48	DEFERRED DEBITS AND CREDITS	24,214	-	-	-	-	-	-	-	-
49	WORKING CAPITAL	38,982	-	-	-	-	-	-	-	-
50	TOTAL RATE BASE	$1,202,677	$0	$0	26,122	47,450	$0	$0	$0	$0
51	RATE OF RETURN	**4.87%**								
52	REVENUE REQUIREMENT	**42,950**	9,550	(530)	2,378	6,831	277	1,281	(1,817)	1,567

AVISTA UTILITIES
IDAHO ELECTRIC RESULTS
TWELVE MONTHS ENDED JUNE 30, 2024
(000'S OF DOLLARS)

Line No.	DESCRIPTION	Pro Forma Employee Benefits	Pro Forma IS/IT	Pro Forma Colstrip/CS2 Maintenance	Pro Forma Colstrip - Adjust Assets Depr. 1/1/2026 (4 mos.)	Pro Forma EDIT (RSGM)	RY2 09.2026 FINAL TOTAL	RY2 INCREMENTAL 09.2026 I Above 09.2025 TOTAL
	Adjustment Number	26.07	26.08	26.09	26.10	26.11		
	Workpaper Reference	E-PEB26	E-ISIT26	E-CCOM26	E-ColR26	E-EDIT26	F-Ttl	F-Ttl
	REVENUES							
1	Total General Business	$0	$0	$0	$0	$0	$307,383	$0
2	Interdepartmental Sales	0	0	0	0	0	268	$0
3	Sales for Resale	0	0	0	0	0	63,872	$279
4	Total Sales of Electricity	0	0	0	0	0	371,523	279
5	Other Revenue	0	0	0	0	0	16,040	$2,026
6	Total Electric Revenue	0	0	0	0	0	387,563	2,305
	EXPENSES							
	Production and Transmission							
7	Operating Expenses	128	0	(1,895)	0	0	96,284	$2,792
8	Purchased Power	0	0	0	0	0	82,405	$6,165
9	Depreciation/Amortization	0	0	0	(982)	0	23,991	(72)
10	Regulatory Amortization	0	0	391	0	0	(1,716)	$391
11	Taxes	0	0	0	0	0	6,686	$218
12	Total Production & Transmission	128	0	(1,504)	(982)	0	207,650	9,494
	Distribution							
13	Operating Expenses	64	0	0	0	0	19,550	$604
14	Depreciation/Amortization	0	0	0	0	0	22,262	$1,469
15	Taxes	0	0	0	0	0	2,302	$58
16	State Income Taxes	0	0	0	0	0	(20)	$0
17	Total Distribution	64	0	0	0	0	44,094	2,131
18	Customer Accounting	22	0	0	0	0	4,995	$193
19	Customer Service & Information	0	0	0	0	0	585	$26
20	Sales Expenses	0	0	0	0	0	0	$0
	Administrative & General							
21	Operating Expenses	105	91	0	0	0	47,788	$1,047
22	Depreciation/Amortization	0	0	0	0	0	22,158	$122
23	Regulatory Amortization	0	0	0	70	0	6,393	$70
24	Taxes	0	0	0	0	0	1,937	$0
25	Total Admin. & General	105	91	0	70	0	78,276	1,239
26	Total Electric Expenses	319	91	(1,504)	(912)	0	335,600	13,083
27	OPERATING INCOME BEFORE FIT	(319)	(91)	1,504	912	0	51,963	(10,778)
	FEDERAL INCOME TAX							
28	Current Accrual	(67)	(19)	316	192	-	(3,151)	($2,263)
29	Debt Interest	-	-	-	-	-	(1,010)	($383)
30	Deferred Income Taxes	0	0	0	0	120	6,007	$120
31	Amortized ITC	0	0	0	0	0	(213)	$0
32	NET OPERATING INCOME	($252)	($72)	$1,188	$720	($120)	$50,331	($8,251)
	RATE BASE							
	PLANT IN SERVICE							
33	Intangible	$0	$0	$0	$0	$0	$118,734	$1,998
34	Production	0	0	0	(36,181)	0	499,557	($14,188)
35	Transmission	0	0	0	0	0	416,436	$14,209
36	Distribution	0	0	0	0	0	986,786	$65,117
37	General	0	0	0	0	0	170,812	$5,493
38	Total Plant in Service	-	-	-	(36,181)	-	2,192,325	72,629
	ACCUMULATED DEPRECIATION/AM						-	-
39	Intangible	0	0	0	0	0	(60,524)	$408
40	Production	0	0	0	30,413	0	(197,884)	$20,943
41	Transmission	0	0	0	0	0	(126,112)	($8,253)
42	Distribution	0	0	0	0	0	(328,272)	($7,438)
43	General	0	0	0	0	0	(67,310)	($5,394)
44	Total Accumulated Depreciation	-	-	-	30,413	-	(780,102)	266
45	NET PLANT	-	-	-	(5,768)	-	1,412,223	72,895
46	DEFERRED TAXES	-	-	-	-	-	(204,938)	($5,091)
47	Net Plant After DFIT	-	-	-	(5,768)	-	1,207,285	67,804
48	DEFERRED DEBITS AND CREDITS	-	-	-	5,768	-	29,982	$5,768
49	WORKING CAPITAL	-	-	-	-	-	38,982	$0
50	TOTAL RATE BASE	$0	$0	$0	$0	$0	$1,276,249	73,572
51	RATE OF RETURN						**3.94%**	
52	REVENUE REQUIREMENT	320	91	(1,511)	(916)	153	**60,624**	**17,674**

AVISTA UTILITIES
IDAHO NATURAL GAS RESULTS
TWELVE MONTHS ENDED JUNE 30, 2024
(000'S OF DOLLARS)

		9.2025 RY1				
		WITH PRESENT RATES			WITH 09.2025 PROPOSED RATES	
Line No.	DESCRIPTION	Actual Per Results Report	Total Adjustments	09.2025 Pro Forma Total	Proposed Revenues & Related Exp	Pro Forma Proposed Total
	a	*b*	*c*	*d*	*e*	*f*
	REVENUES					
1	Total General Business	$108,568	$ (59,620)	$48,948	$ 8,803	$57,751
2	Total Transportation	670	1	671		671
3	Other Revenues	22,160	(20,653)	1,507		1,507
4	Total Gas Revenues	131,398	(80,272)	51,126	8,803	59,929
	EXPENSES					
	Production Expenses					
5	City Gate Purchases	77,415	(77,415)	-		-
6	Purchased Gas Expense	368	(11)	357		357
7	Net Nat Gas Storage Trans	939	(939)	-		-
8	Total Production	78,722	(78,365)	357	-	357
	Underground Storage					
9	Operating Expenses	847	97	944		944
10	Depreciation	249	21	270		270
11	Taxes	91	13	104		104
12	Total Underground Storage	1,187	131	1,318	-	1,318
	Distribution					
13	Operating Expenses	8,374	(699)	7,675		7,675
14	Depreciation	7,087	157	7,244		7,244
15	Taxes	2,103	(1,039)	1,064		1,064
16	State Income Taxes	(5)	-	(5)	-	(5)
17	Total Distribution	17,559	(1,581)	15,978	-	15,978
18	Customer Accounting	2,655	63	2,718	19	2,737
19	Customer Service & Information	4,346	(3,989)	357		357
20	Sales Expenses	-	-	-		-
	Administrative & General					
21	Operating Expenses	9,341	789	10,130	19	10,149
22	Depreciation/Amortization	4,719	83	4,802		4,802
23	Regulatory Amortizations	(2,409)	5,345	2,936		2,936
24	Taxes	521	-	521		521
25	Total Admin. & General	12,172	6,217	18,389	19	18,408
26	Total Gas Expense	116,641	(77,523)	39,118	38	39,156
27	OPERATING INCOME BEFORE FIT	14,757	(2,749)	12,008	8,765	20,773
	FEDERAL INCOME TAX					
28	Current Accrual	5,810	(432)	5,378	1,841	7,219
29	Debt Interest	-	(84)	(84)	-	(84)
30	Deferred FIT	(5,664)	1,108	(4,556)		(4,556)
31	Amort ITC	-	-	-		-
32	NET OPERATING INCOME	$14,611	($3,341)	$11,270	$6,924	$18,194
	RATE BASE: PLANT IN SERVICE					
33	Underground Storage	$16,721	$1,577	$18,298		$18,298
34	Distribution Plant	317,858	23,784	341,642		341,642
35	General Plant	52,494	2,827	55,321		55,321
36	Total Plant in Service	387,073	28,188	415,261	-	415,261
	ACCUMULATED DEPREC/AMORT					
37	Underground Storage	(6,385)	(561)	(6,946)		(6,946)
38	Distribution Plant	(108,664)	(10,433)	(119,097)		(119,097)
39	General Plant	(23,238)	(2,346)	(25,584)		(25,584)
40	Total Accum. Depreciation/Amort.	(138,287)	(13,340)	(151,627)	-	(151,627)
41	NET PLANT	248,786	14,848	263,634	-	263,634
42	DEFERRED FIT	(34,077)	1,481	(32,596)		(32,596)
43	Net Plant After DFIT	214,709	16,329	231,038	-	231,038
44	GAS INVENTORY	5,685	-	5,685		5,685
45	GAIN ON SALE OF BUILDING	-	-	-		-
46	OTHER	(7,523)	-	(7,523)		(7,523)
47	WORKING CAPITAL	7,907	(205)	7,702		7,702
48	TOTAL RATE BASE	$220,778	$16,124	$236,902	$0	$236,902
49	RATE OF RETURN	6.62%		4.76%		7.68%

AVISTA UTILITIES
IDAHO NATURAL GAS RESULTS
TWELVE MONTHS ENDED JUNE 30, 2024
(000'S OF DOLLARS)

		09.2026 RY2					
		WITH 09.2025 PROPOSED RATES				WITH 09.2026 PROPOSED RATES	
Line No.	DESCRIPTION	09.2025 Pro Forma Total	09.2026 Total Adjustments	09.2026 Pro Forma Total	09.2025 Proposed Revenues & Related Exp	09.2026 Proposed Revenues & Related Exp	09.2026 Pro Forma Proposed Total
	a	b	c	d	e	f	g
	REVENUES						
1	Total General Business	$48,948		$48,948	$ 8,803	$983	$58,734
2	Total Transportation	671	-	671			671
3	Other Revenues	1,507	732	2,239			2,239
4	Total Gas Revenues	51,126	732	51,858	8,803	983	61,644
	EXPENSES						
	Production Expenses						
5	City Gate Purchases	-	-	-			-
6	Purchased Gas Expense	357	10	367			367
7	Net Nat Gas Storage Trans	-	-	-			-
8	Total Production	357	10	367	-	-	367
	Underground Storage						
9	Operating Expenses	944	38	982			982
10	Depreciation	270	10	280			280
11	Taxes	104	7	111			111
12	Total Underground Storage	1,318	55	1,373	-	-	1,373
	Distribution						
13	Operating Expenses	7,675	326	8,001			8,001
14	Depreciation	7,244	182	7,426			7,426
15	Taxes	1,064	76	1,140			1,140
16	State Income Taxes	(5)	-	(5)	-	-	(5)
17	Total Distribution	15,978	584	16,562	-	-	16,562
18	Customer Accounting	2,718	124	2,842	19	2	2,863
19	Customer Service & Information	357	17	374			374
20	Sales Expenses	-	-	-			-
	Administrative & General						
21	Operating Expenses	10,130	264	10,394	19	2	10,415
22	Depreciation/Amortization	4,802	60	4,862			4,862
23	Regulatory Amortizations	2,936	-	2,936			2,936
24	Taxes	521	-	521			521
25	Total Admin. & General	18,389	324	18,713	19	2	18,734
26	Total Gas Expense	39,118	1,114	40,232	38	4	40,274
27	OPERATING INCOME BEFORE FIT	12,008	(382)	11,626	8,765	979	21,370
	FEDERAL INCOME TAX						
28	Current Accrual	5,378	(80)	5,298	1,841	206	7,345
29	Debt Interest	(84)	(34)	(118)	-	-	(118)
30	Deferred FIT	(4,556)	-	(4,556)			(4,556)
31	Amort ITC	-	-	-			-
32	NET OPERATING INCOME	$11,270	($267)	$11,002	$6,924	$773	$18,699
	RATE BASE: PLANT IN SERVICE						
33	Underground Storage	$18,298	$699	$18,997			$18,997
34	Distribution Plant	341,642	8,611	350,253			350,253
35	General Plant	55,321	1,743	57,064			57,064
36	Total Plant in Service	415,261	11,053	426,314	-	-	426,314
	ACCUMULATED DEPREC/AMORT						
37	Underground Storage	(6,946)	(273)	(7,219)			(7,219)
38	Distribution Plant	(119,097)	(3,316)	(122,413)			(122,413)
39	General Plant	(25,584)	(1,021)	(26,605)			(26,605)
40	Total Accum. Depreciation/Amort.	(151,627)	(4,610)	(156,237)	-	-	(156,237)
41	NET PLANT	263,634	6,443	270,077	-	-	270,077
42	DEFERRED FIT	(32,596)	145	(32,451)			(32,451)
43	Net Plant After DFIT	231,038	6,588	237,626	-	-	237,626
44	GAS INVENTORY	5,685	-	5,685			5,685
45	GAIN ON SALE OF BUILDING	-	-	-			-
46	OTHER	(7,523)	-	(7,523)			(7,523)
47	WORKING CAPITAL	7,702	-	7,702			7,702
48	TOTAL RATE BASE	$236,902	$6,588	$243,490	$0	$0	$243,490
49	RATE OF RETURN	4.76%		4.52%			7.68%

AVISTA UTILITIES
Calculation of General Revenue Requirement
Idaho - Natural Gas
TWELVE MONTHS ENDED JUNE 30, 2024

Line No.	Description	RY1 Sep-25 (000's of Dollars)	RY2 Sep-26 (000's of Dollars)	Incremental RY2 Sep-26 (000's of Dollars)
1	Pro Forma Rate Base	$236,902	$ 243,490	
2	Proposed Rate of Return	7.68%	7.68%	
3	Net Operating Income Requirement	$18,194	$18,700	
4	Pro Forma Net Operating Income	$11,270	$ 11,002	
5	Net Operating Income Deficiency	$6,924	$7,698	$773
6	Conversion Factor	0.78657	0.78657	0.78657
7	Revenue Requirement	**$8,803**	$9,786	**$983**
8	Total Base Distribution Revenues	$49,619		$58,422
9	Percentage Base Distribution Revenue Increase	**17.74%**		**1.68%**
10	Total Present Billed Revenue	$85,293		$94,096
11	Percentage Billed Revenue Increase	**10.32%**		**1.04%**

AVISTA UTILITIES
PRO FORMA COST OF CAPITAL
Idaho - Natural Gas

Proposed:

Component	Capital Structure	Pro Forma Cost	Pro Forma Weighted Cost
Total Debt	50.00%	4.95%	2.48%
Common Equity	50.00%	10.40%	5.20%
Total	100.00%		7.68%

AVISTA UTILITIES
Revenue Conversion Factor
Idaho - Natural Gas System
TWELVE MONTHS ENDED JUNE 30, 2024

Line No.		Description	Factor
1		**Revenues**	1.000000
		Expenses:	
2		Uncollectibles	0.002212
3		Commission Fees	0.002127
4		Idaho State Income Tax	0.000000
5		Total Expenses	0.004339
6		Net Operating Income Before FIT	0.995661
7	21%	Federal Income Tax @ 21%	0.209089
8		REVENUE CONVERSION FACTOR	0.786572

Rate Year September 1, 2025 - August 31, 2026

(000'S OF DOLLARS)

Line No.	DESCRIPTION		Per Results Report	Accumulated Deferred FIT Rate Base	Deferred Debits, Credits & Reg Amortizations	Working Capital	Restating 06.2024 Capital EOP	Eliminate B & O Taxes	Uncollectible Expense	Regulatory Expense
	Adjustment Number		**1.00**	**1.01**	**1.02**	**1.03**	**1.04**	**2.01**	**2.02**	**2.03**
	Workpaper Reference		**G-ROO**	**G-DFIT**	**G-DDC**	**G-WC**	**G-RCAP**	**G-EBO**	**G-UE**	**G-RE**
	REVENUES									
1	Total General Business		$108,568	$ -	$0	$ -	$ -	$ (1,861)	$0	$0
2	Total Transportation		670	-	-	-	-	(10)	-	-
3	Other Revenues		22,160	-	-	-	-	-	-	-
4	Total Gas Revenues		$131,398	-	$0	-	-	(1,871)	$0	$0
	EXPENSES									
	Production Expenses									
5	City Gate Purchases		77,415	-	-	-	-	-	-	-
6	Purchased Gas Expense		368	-	-	-	-	-	-	-
7	Net Nat Gas Storage Trans		939	-	-	-	-	-	-	-
8	Total Production		78,722	-	-	-	-	-	-	-
	Underground Storage									
9	Operating Expenses		847	-	-	-	-	-	-	-
10	Depreciation/Amortization		249	-	-	-	-	-	-	-
11	Taxes		91	-	-	-	-	-	-	-
12	Total Underground Storage		1,187	-	-	-	-	-	-	-
	Distribution									
13	Operating Expenses		8,374	-	-	-	-	-	-	-
14	Depreciation/Amortization		7,087	-	-	-	-	-	-	-
15	Taxes		2,103	-	-	-	-	(1,871)	-	-
16	State Income Taxes	**0.000000**	(5)	-	-	-	-	-	-	-
17	Total Distribution		17,559	-	-	-	-	(1,871)	-	-
18	Customer Accounting		2,655	-	-	-	-	-	(115)	-
19	Customer Service & Information		4,346	-	-	-	-	-	-	-
20	Sales Expenses		-	-	-	-	-	-	-	-
	Administrative & General									
21	Operating Expenses		9,341	-	-	-	-	-	-	35
22	Depreciation/Amortization		4,719	-	-	-	-	-	-	-
23	Regulatory Amortizations		(2,409)	-	2,416	-	-	-	-	-
24	Taxes		521	-	-	-	-	-	-	-
25	Total Admin. & General		12,172	-	2,416	-	-	-	-	35
26	Total Gas Expense		116,641	-	2,416	-	-	(1,871)	(115)	35
27	OPERATING INCOME BEFORE FIT		14,757	-	(2,416)	-	-	-	115	(35)
	FEDERAL INCOME TAX									
28	Current Accrual		5,810	-	(507)	-	-	-	24	(7)
29	Debt Interest		-	(3)	-	1	(26)	-	-	-
30	Deferred FIT		(5,664)	-	-	-	-	-	-	-
31	Amort ITC		-				-	-	-	-
32	NET OPERATING INCOME		$ 14,611	$ 3	$ (1,909)	$ (1)	$ 26	$ -	$ 91	$ (27)
	RATE BASE									
	PLANT IN SERVICE									
33	Underground Storage		$16,721	$ -	$0	$ -	$ 561	$ -	$0	$0
34	Distribution Plant		317,858	-	-	-	7,046	-	-	-
35	General Plant		52,494	-	-	-	1,005	-	-	-
36	Total Plant in Service		387,073	-	-	-	8,612	-	-	-
	ACCUMULATED DEPRECIATION/AMORT									
37	Underground Storage		(6,385)	-	-	-	(126)	-	-	-
38	Distribution Plant		(108,664)	-	-	-	(3,061)	-	-	-
39	General Plant		(23,238)	-	-	-	(588)	-	-	-
40	Total Accumulated Depreciation/Amortization		(138,287)	-	-	-	(3,775)	-	-	-
41	NET PLANT		248,786	-	-	-	4,837	-	-	-
42	DEFERRED TAXES		(34,077)	589	-	-	136	-	-	-
43	Net Plant After DFIT		214,709	589	-	-	4,973	-	-	-
44	GAS INVENTORY		5,685	-	-	-	-	-	-	-
45	GAIN ON SALE OF BUILDING		-	-	-	-	-	-	-	-
46	OTHER		(7,523)		-					
47	WORKING CAPITAL		7,907	-	-	(205)	-	-	-	-
48	**TOTAL RATE BASE**		**$ 220,778**	**$ 589**	**$ -**	**$ (205)**	**$ 4,973**	**$ -**	**$ -**	**$ -**
49	RATE OF RETURN		6.62%							
50	REVENUE REQUIREMENT		2,981	54	2,427	(19)	453	-	(115)	35

AVISTA UTILITIES
IDAHO NATURAL GAS RESULTS
TWELVE MONTHS ENDED JUNE 30, 2024
(000'S OF DOLLARS)

Line No.	DESCRIPTION	Injuries and Damages	FIT / DFIT Expense	SIT/SITC Expense	Revenue Normalization & Gas Cost Adj.	Miscellaneous Restating	Restate Incentive	Restate Debt Interest	Restated Total
	Adjustment Number	**2.04**	**2.05**	**2.06**	**2.07**	**2.08**	**2.09**	**2.10**	
	Workpaper Reference	**G-ID**	**G-FIT**	**G-SIT**	**G-RNGC**	**G-MR**	**G-RI**	**G-RDI**	**R-Ttl**
	REVENUES								
1	Total General Business	$0	$0	$0	$ (57,759)	$0	$0	$ -	**$48,948**
2	Total Transportation	-	-	-	11	-	-	-	**671**
3	Other Revenues	-	-	-	(22,037)	-	-	-	**123**
4	Total Gas Revenues	$0	$0	$0	(79,785)	$0	$0	-	**49,742**
	EXPENSES								
	Production Expenses								
5	City Gate Purchases	-	-	-	(77,415)	-	-	-	**-**
6	Purchased Gas Expense	-	-	-	(38)	-	-	-	**330**
7	Net Nat Gas Storage Trans	-	-	-	(939)	-	-	-	**-**
8	Total Production	-	-	-	(78,392)	-	-	-	**330**
	Underground Storage								
9	Operating Expenses	-	-	-	-	-	-	-	**847**
10	Depreciation/Amortization	-	-	-	-	-	-	-	**249**
11	Taxes	-	-	-	-	-	-	-	**91**
12	Total Underground Storage	-	-	-	-	-	-	-	**1,187**
	Distribution								
13	Operating Expenses	-	-	-	-	(1,827)	-	-	**6,547**
14	Depreciation/Amortization	-	-	-	-	-	-	-	**7,087**
15	Taxes	-	-	-	-	-	-	-	**232**
16	State Income Taxes	-	-	-	-	-	-	-	**(5)**
17	Total Distribution	-	-	-	-	(1,827)	-	-	**13,861**
18	Customer Accounting	-	-	-	(128)	-	-	-	**2,412**
19	Customer Service & Information	-	-	-	(4,032)	5	-	-	**319**
20	Sales Expenses	-	-	-	-	-	-	-	**-**
	Administrative & General								
21	Operating Expenses	(13)	-	-	(124)	(95)	127	-	**9,271**
22	Depreciation/Amortization	-	-	-	-	-	-	-	**4,719**
23	Regulatory Amortizations	-	-	-	-	-	-		**7**
24	Taxes	-	-	-	-	-	-	-	**521**
25	Total Admin. & General	(13)	-	-	(124)	(95)	127	-	**14,518**
26	Total Gas Expense	(13)	-	-	(82,676)	(1,917)	127	-	**32,628**
27	OPERATING INCOME BEFORE FIT	13	-	-	2,891	1,917	(127)	-	**17,114**
	FEDERAL INCOME TAX								
28	Current Accrual	3	-	-	607	402	(27)	196	**6,501**
29	Debt Interest	-	-	-	-	-	-	-	**(28)**
30	Deferred FIT	-	-	-	1,088	-	-	-	**(4,576)**
31	Amort ITC	-	-	-	-	-	-	-	**-**
32	NET OPERATING INCOME	$ 10	$ -	$ -	$ 1,196	$ 1,514	$ (100)	$ (196)	**$ 15,217**
	RATE BASE								
	PLANT IN SERVICE								
33	Underground Storage	$0	$0	$0	$ -	$0	$0	$ -	**$ 17,282**
34	Distribution Plant	-	-	-	-	-	-	-	**324,904**
35	General Plant	-	-	-	-	-	-	-	**53,499**
36	Total Plant in Service	-	-	-	-	-	-	-	**395,685**
	ACCUMULATED DEPRECIATION/AM(								
37	Underground Storage	-	-	-	-	-	-	-	**(6,511)**
38	Distribution Plant	-	-	-	-	-	-	-	**(111,725)**
39	General Plant	-	-	-	-	-	-	-	**(23,826)**
40	Total Accumulated Depreciation/Amortiza	-	-	-	-	-	-	-	**(142,062)**
41	NET PLANT	-	-	-	-	-	-	-	**253,623**
42	DEFERRED TAXES	-	-	-	-	-	-	-	**(33,352)**
43	Net Plant After DFIT	-	-	-	-	-	-	-	**220,271**
44	GAS INVENTORY	-	-	-	-	-	-	-	**5,685**
45	GAIN ON SALE OF BUILDING	-	-	-	-	-	-	-	**-**
46	OTHER								**(7,523)**
47	WORKING CAPITAL	-	-	-	-	-	-	-	**7,702**
48	**TOTAL RATE BASE**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 226,135**
49	RATE OF RETURN								**6.73%**
50	REVENUE REQUIREMENT	(13)	-	-	(1,520)	(1,925)	128	249	**2,733**

AVISTA UTILITIES
IDAHO NATURAL GAS RESULTS
TWELVE MONTHS ENDED JUNE 30, 2024
(000'S OF DOLLARS)

Line No.	DESCRIPTION	Pro Forma Labor Non-Exec	Pro Forma Labor Exec	Pro Forma Employee Benefits	Pro Forma IS/IT Costs	Pro Forma Property Tax	Pro Forma Insurance Expense	Pro Forma EDIT (RSGM)	Planned Capital Add 08.2025 EOP	Planned Capital Add 08.2026 AMA
	Adjustment Number	**3.01**	**3.02**	**3.03**	**3.04**	**3.05**	**3.06**	**3.07**	**3.08**	**3.09**
	Workpaper Reference	**G-PLN**	**G-PLE**	**G-PEB25**	**G-ISIT**	**G-PPT**	**G-Ins**	**G-RSGM**	**G-CAP25E**	**G-CAP26A**
	REVENUES									
1	Total General Business	$0	$0	$0	$0	$0	$0	$ -	$ -	$ -
2	Total Transportation	-	-	-	-	-	-	-	-	-
3	Other Revenues	-	-	-	-	-	-	-	-	-
4	Total Gas Revenues	$0	$0	$0	$0	$0	$0	-	-	-
	EXPENSES									
	Production Expenses									
5	City Gate Purchases	-	-	-	-	-	-	-	-	-
6	Purchased Gas Expense	20	-	7	-	-	-	-	-	-
7	Net Nat Gas Storage Trans	-	-	-	-	-	-	-	-	-
8	Total Production	20	-	7	-	-	-	-	-	-
	Underground Storage									
9	Operating Expenses	-	-	-	-	-	-	-	-	-
10	Depreciation/Amortization	-	-	-	-	-	-	-	11	10
11	Taxes	-	-	-	-	13	-	-	-	-
12	Total Underground Storage	-	-	-	-	13	-	-	11	10
	Distribution									
13	Operating Expenses	454		166	-	-	-	-	-	-
14	Depreciation/Amortization	-	-	-	-	-	-	-	(26)	183
15	Taxes	-	-	-	-	832	-	-	-	-
16	State Income Taxes	-	-	-	-	-	-	-	-	-
17	Total Distribution	454	-	166	-	832	-	-	(26)	183
18	Customer Accounting	147	-	52	-		-	-	-	-
19	Customer Service & Information	9	-	3	-	-	-	-	-	-
20	Sales Expenses	-	-	-	-	-	-	-	-	-
	Administrative & General									
21	Operating Expenses	270	(18)	98	55	-	282	-	-	-
22	Depreciation/Amortization	-	-	-	-	-	-	-	173	(90)
23	Regulatory Amortizations						78	-		
24	Taxes	-	-	-	-	-	-	-	-	-
25	Total Admin. & General	270	(18)	98	55	-	360	-	173	(90)
26	Total Gas Expense	900	(18)	326	55	845	360	-	158	103
27	OPERATING INCOME BEFORE FIT	(900)	18	(326)	(55)	(845)	(360)	-	(158)	(103)
	FEDERAL INCOME TAX									
28	Current Accrual	(189)	4	(68)	(12)	(177)	(126)	-	(33)	(22)
29	Debt Interest	-	-	-	-	-	-	-	(34)	(22)
30	Deferred FIT	-	-	-	-	-	-	20	-	-
31	Amort ITC	-	-	-	-	-	-	-	-	-
32	NET OPERATING INCOME	$ (711)	$ 14	$ (258)	$ (43)	$ (668)	$ (234)	$ (20)	$ (91)	$ (60)
	RATE BASE									
	PLANT IN SERVICE									
33	Underground Storage	$0	$0	$0	$0	$0	$0	$ -	$ 665	$ 351
34	Distribution Plant	-	-	-	-	-	-	-	12,677	4,061
35	General Plant	-	-	-	-	-	-	-	1,365	457
36	Total Plant in Service	-	-	-	-	-	-	-	14,707	4,869
	ACCUMULATED DEPRECIATION/AM									
37	Underground Storage	-	-	-	-	-	-	-	(301)	(134)
38	Distribution Plant	-	-	-	-	-	-	-	(7,439)	67
39	General Plant	-	-	-	-	-	-	-	(1,013)	(745)
40	Total Accumulated Depreciation/Amortiza	-	-	-	-	-	-	-	(8,753)	(812)
41	NET PLANT	-	-	-	-	-	-	-	5,954	4,057
42	DEFERRED TAXES					-			635	121
43	Net Plant After DFIT	-	-	-	-	-	-	-	6,589	4,178
44	GAS INVENTORY					-			-	-
45	GAIN ON SALE OF BUILDING					-				
46	OTHER									
47	WORKING CAPITAL					-				
48	**TOTAL RATE BASE**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 6,589**	**$ 4,178**
49	RATE OF RETURN									
50	REVENUE REQUIREMENT	904	(18)	327	55	849	297	25	758	484

AVISTA UTILITIES
IDAHO NATURAL GAS RESULTS
TWELVE MONTHS ENDED JUNE 30, 2024

(000'S OF DOLLARS)

Line No.	DESCRIPTION	Pro Forma Revenue & O&M Offsets	Pro Forma Regulatory Amortizations	Pro Forma Misc. O&M Expense	Pro Forma Locates Expense	RY1 09.2025 FINAL TOTAL
	Adjustment Number	3.10	3.11	3.12	3.13	
	Workpaper Reference	G-POFF25	G-PRA	G-PME25	G-LOC	F-Ttl
	REVENUES					
1	Total General Business	$ -	$ -	$ -	$ -	$48,948
2	Total Transportation	-	-	-	-	671
3	Other Revenues	1,384	-	-	-	1,507
4	Total Gas Revenues	1,384	-	-	-	51,126
	EXPENSES					
	Production Expenses					
5	City Gate Purchases	-	-	-	-	-
6	Purchased Gas Expense	-	-	-		357
7	Net Nat Gas Storage Trans	-	-	-	-	-
8	Total Production	-	-	-	-	357
	Underground Storage					
9	Operating Expenses	-	-	97	-	944
10	Depreciation/Amortization	-	-	-	-	270
11	Taxes	-	-	-	-	104
12	Total Underground Storage	-	-	97	-	1,318
	Distribution					
13	Operating Expenses	(51)	-	237	322	7,675
14	Depreciation/Amortization	-	-	-	-	7,244
15	Taxes	-	-	-	-	1,064
16	State Income Taxes	-	-	-	-	(5)
17	Total Distribution	(51)	-	237	322	15,978
18	Customer Accounting	-	-	107		2,718
19	Customer Service & Information	-	-	26		357
20	Sales Expenses	-	-	-	-	-
	Administrative & General					
21	Operating Expenses	(66)	-	238		10,130
22	Depreciation/Amortization	-	-	-	-	4,802
23	Regulatory Amortizations		2,851			2,936
24	Taxes	-	-	-	-	521
25	Total Admin. & General	(66)	2,851	238	-	18,389
26	Total Gas Expense	(117)	2,851	705	322	39,118
27	OPERATING INCOME BEFORE FIT	1,501	(2,851)	(705)	(322)	12,008
	FEDERAL INCOME TAX					
28	Current Accrual	315	(599)	(148)	(68)	5,378
29	Debt Interest	-	-	-	-	(84)
30	Deferred FIT	-	-	-	-	(4,556)
31	Amort ITC	-	-	-	-	-
32	NET OPERATING INCOME	$ 1,186	$ (2,252)	$ (557)	$ (254)	$ 11,270
	RATE BASE					
	PLANT IN SERVICE					
33	Underground Storage	$ -	$ -	$ -	$ -	$ 18,298
34	Distribution Plant	-	-	-	-	341,642
35	General Plant	-	-	-	-	55,321
36	Total Plant in Service	-	-	-	-	415,261
	ACCUMULATED DEPRECIATION/AM(					
37	Underground Storage	-	-	-	-	(6,946)
38	Distribution Plant	-	-	-	-	(119,097)
39	General Plant	-	-	-	-	(25,584)
40	Total Accumulated Depreciation/Amortiza	-	-	-	-	(151,627)
41	NET PLANT	-	-	-	-	263,634
42	DEFERRED TAXES	-	-			(32,596)
43	Net Plant After DFIT	-	-	-	-	231,038
44	GAS INVENTORY	-	-	-	-	5,685
45	GAIN ON SALE OF BUILDING			-	-	
46	OTHER					(7,523)
47	WORKING CAPITAL			-	-	7,702
48	**TOTAL RATE BASE**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 236,902**
49	RATE OF RETURN					4.76%
50	REVENUE REQUIREMENT	(1,508)	2,863	708	323	8,803

Exhibit No. 4
Case Nos. AVU-E-25-01 and AVU-G-25-01
K. Schultz, Avista

AVISTA UTILITIES
IDAHO NATURAL GAS RESULTS
TWELVE MONTHS ENDED JUNE 30, 2024
(000'S OF DOLLARS)

Rate Year September 1, 2026 - August 31, 2027

Line No.	DESCRIPTION	09.2025 FINAL TOTAL	Planned Capital Add 08.2026 EOP	Planned Capital Add 08.2027 AMA	Pro Forma Property Tax	Pro Forma Labor Non-Exec	Pro Forma Revenue & O&M Offsets	Pro Forma Misc. O&M Expense
	Adjustment Number		26.01	26.02	26.03	26.04	26.05	26.06
	Workpaper Reference	F-Ttl	G-CAP26E	G-CAP27A	G-PPT26	G-PLN26	G-POFF26	E-PME26
	REVENUES							
1	Total General Business	$ 48,948	$ -	$ -	$ -	$ -	$ -	$ -
2	Total Transportation	671	-	-	-	-	-	-
3	Other Revenues	1,507	-	-	-	-	732	-
4	Total Gas Revenues	51,126	-	-	-	-	732	-
	EXPENSES							
	Production Expenses							
5	City Gate Purchases	-	-	-	-	-	-	-
6	Purchased Gas Expense	357	-	-	-	8	-	-
7	Net Nat Gas Storage Trans	-	-	-	-	-	-	-
8	Total Production	357	-	-	-	8	-	-
	Underground Storage							
9	Operating Expenses	944	-	-	-	-	(7)	45
10	Depreciation/Amortization	270	-	10	-	-	-	-
11	Taxes	104	-	-	7	-	-	-
12	Total Underground Storage	1,318	-	10	7	-	(7)	45
	Distribution							
13	Operating Expenses	7,675	-	-	-	174	-	109
14	Depreciation/Amortization	7,244	-	182	-	-	-	-
15	Taxes	1,064	-	-	76	-	-	-
16	State Income Taxes	(5)	-	-	-	-	-	-
17	Total Distribution	15,978	-	182	76	174	-	109
18	Customer Accounting	2,718	-	-		61	-	49
19	Customer Service & Information	357	-	-	-	4	-	12
20	Sales Expenses	-	-	-	-	-	-	-
	Administrative & General							
21	Operating Expenses	10,130	-	-	-	111	(8)	110
22	Depreciation/Amortization	4,802	-	60	-	-	-	-
23	Regulatory Amortizations	2,936	-	-	-	-	-	-
24	Taxes	521	-	-	-	-	-	-
25	Total Admin. & General	18,389	-	60	-	111	(8)	110
26	Total Gas Expense	39,118	-	252	83	358	(15)	325
27	OPERATING INCOME BEFORE FIT	12,008	-	(252)	(83)	(358)	747	(325)
	FEDERAL INCOME TAX							
28	Current Accrual	5,378	-	(53)	(17)	(75)	157	(68)
29	Debt Interest	(84)	(3)	(31)	-	-	-	-
30	Deferred FIT	(4,556)	-	-	-	-	-	-
31	Amort ITC	-	-	-	-	-	-	-
32	NET OPERATING INCOME	$ 11,270	$ 3	$ (168)	$ (66)	$ (283)	$ 590	$ (257)
	RATE BASE							
	PLANT IN SERVICE							
33	Underground Storage	$ 18,298	$ 350	$ 349	$ -	$ -	$ -	$ -
34	Distribution Plant	341,642	4,049	4,562	-	-	-	-
35	General Plant	55,321	425	1,318	-	-	-	-
36	Total Plant in Service	415,261	4,824	6,229	-	-	-	-
	ACCUMULATED DEPRECIATION/AMO							
37	Underground Storage	(6,946)	(135)	(138)	-	-	-	-
38	Distribution Plant	(119,097)	(3,359)	43	-	-	-	-
39	General Plant	(25,584)	(760)	(261)	-	-	-	-
40	Total Accumulated Depreciation/Amortiza	(151,627)	(4,254)	(356)	-	-	-	-
41	NET PLANT	263,634	570	5,873	-	-	-	-
42	DEFERRED TAXES	(32,596)	60	85	-	-	-	-
43	Net Plant After DFIT	231,038	630	5,958	-	-	-	-
44	GAS INVENTORY	5,685	-	-	-	-	-	-
45	GAIN ON SALE OF BUILDING	-	-	-	-	-	-	-
46	OTHER	(7,523)	-	-	-	-	-	-
47	WORKING CAPITAL	7,702	-	-	-	-	-	-
48	**TOTAL RATE BASE**	**$ 236,902**	**$ 630**	**$ 5,958**	**$ -**	**$ -**	**$ -**	**$ -**
49	RATE OF RETURN	4.76%						
50	REVENUE REQUIREMENT	8,803	57	795	83	360	(750)	326

AVISTA UTILITIES
IDAHO NATURAL GAS RESULTS
TWELVE MONTHS ENDED JUNE 30, 2024
(000'S OF DOLLARS)

Line No.	DESCRIPTION	Pro Forma Employee Benefits	Pro Forma IS/IT	RY2 09.2026 FINAL TOTAL	RY2 INCREMENTAL 09.2026 I Above 09.2025 TOTAL
	Adjustment Number	26.07	26.08		
	Workpaper Reference	E-PEB26	G-ISIT26	F-Ttl	F-Ttl
	REVENUES				
1	Total General Business	$ -	$ -	$48,948	$ -
2	Total Transportation	-	-	671	-
3	Other Revenues	-	-	2,239	732
4	Total Gas Revenues	-	-	51,858	732
	EXPENSES				
	Production Expenses				
5	City Gate Purchases	-	-	-	-
6	Purchased Gas Expense	2	-	367	10
7	Net Nat Gas Storage Trans	-	-	-	-
8	Total Production	2	-	367	10
	Underground Storage				
9	Operating Expenses	-	-	982	38
10	Depreciation/Amortization	-	-	280	10
11	Taxes	-	-	111	7
12	Total Underground Storage	-	-	1,373	55
	Distribution				
13	Operating Expenses	43	-	8,001	326
14	Depreciation/Amortization	-	-	7,426	182
15	Taxes	-	-	1,140	76
16	State Income Taxes	-	-	(5)	-
17	Total Distribution	43	-	16,562	584
18	Customer Accounting	14		2,842	124
19	Customer Service & Information	1	-	374	17
20	Sales Expenses	-	-	-	-
	Administrative & General				
21	Operating Expenses	25	26	10,394	264
22	Depreciation/Amortization	-	-	4,862	60
23	Regulatory Amortizations	-	-	2,936	-
24	Taxes	-	-	521	-
25	Total Admin. & General	25	26	18,713	324
26	Total Gas Expense	85	26	40,232	1,114
27	OPERATING INCOME BEFORE FIT	(85)	(26)	11,626	(382)
	FEDERAL INCOME TAX				
28	Current Accrual	(18)	(5)	5,298	(80)
29	Debt Interest	-	-	(118)	(34)
30	Deferred FIT	-	-	(4,556)	-
31	Amort ITC	-	-	-	-
32	NET OPERATING INCOME	$ (67)	$ (21)	$ 11,002	$ (267)
	RATE BASE				
	PLANT IN SERVICE				
33	Underground Storage	$ -	$ -	$ 18,997	699
34	Distribution Plant	-	-	350,253	8,611
35	General Plant	-	-	57,064	1,743
36	Total Plant in Service	-	-	426,314	11,053
	ACCUMULATED DEPRECIATION/AM(				
37	Underground Storage	-	-	(7,219)	(273)
38	Distribution Plant	-	-	(122,413)	(3,316)
39	General Plant	-	-	(26,605)	(1,021)
40	Total Accumulated Depreciation/Amortiza	-	-	(156,237)	(4,610)
41	NET PLANT	-	-	270,077	6,443
42	DEFERRED TAXES	-	-	(32,451)	145
43	Net Plant After DFIT	-	-	237,626	6,588
44	GAS INVENTORY	-	-	5,685	-
45	GAIN ON SALE OF BUILDING	-	-	-	
46	OTHER	-	-	(7,523)	-
47	WORKING CAPITAL	-	-	7,702	-
48	**TOTAL RATE BASE**	**$ -**	**$ -**	**$ 243,490**	**$ 6,588**
49	RATE OF RETURN			4.52%	
50	REVENUE REQUIREMENT	85	26	9,786	983