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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION	)	CASE NO. AVU-E-21-01
OF AVISTA CORPORATION FOR THE	)	CASE NO. AVU-G-21-01
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	)	ELIZABETH M. ANDREWS
	)	

FOR AVISTA CORPORATION

(ELECTRIC AND NATURAL GAS)

TABLE OF CONTENTS

I. INTRODUCTION

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

A. My name is Elizabeth M. Andrews. I am employed by Avista Corporation as Senior Manager of Revenue Requirements in the Regulatory Affairs Department. My business address is 1411 East Mission, Spokane, Washington.

Q. Would you please describe your education and business experience?

A. I am a 1990 graduate of Eastern Washington University with a Bachelor of Arts Degree in Business Administration, majoring in Accounting. That same year, I passed the November Certified Public Accountant exam, earning my CPA License in August 1991.[1] I worked for Lemaster & Daniels, CPAs from 1990 to 1993, before joining the Company in August 1993. I served in various positions within the sections of the Finance Department, including General Ledger Accountant and Systems Support Analyst until 2000. In 2000, I was hired into the State and Federal Regulation Department, now Regulatory Affairs, as a Regulatory Analyst until my promotion to Manager of Revenue Requirements in early 2007, and later promotion to Senior Manager of Revenue Requirements. I have also attended several utility accounting, ratemaking and leadership courses.

Q. As Senior Manager of Revenue Requirements, what are your responsibilities?

A. Aside from special projects, I am responsible for the preparation of normalized revenue requirement and ratemaking studies for the various jurisdictions in

[1] Currently I keep a CPA-Inactive status with regards to my CPA license.

which the Company provides utility services. Since 2000, I have led, or assisted in, the Company's electric and/or natural gas general rate filings in Washington, Idaho and Oregon.

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, 2021 through August 31, 2023. 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.

In addition to discussing the Company's needed rate relief, I will discuss the Company's requests in this case associated with its Wildfire Resiliency Plan ("Wildfire Plan") and discuss the Company's proposal to establish a Wildfire expense balancing account to track wildfire expenses during the 10-year Wildfire Plan.

Finally, I will discuss, along with Company witness Mr. Krasselt, the Company's Tax Accounting Application filed with this Commission on October 30, 2020 (Case Nos. AVU-E-20-12 and AVU-G-20-07), requesting authorization to change its accounting for federal income tax expense from a normalization method to a flow-through method for certain plant basis adjustments, including tax Industry Director Directive No. 5 ("IDD #5"), and meters.[2] / [3] Approval of the Company's application would provide immediate benefits to

[2] Discussed further below, IDD #5 relates to mixed services costs that are part of the capitalized book costs of utility property but can be capitalized to inventory and expensed for tax purposes as a cost of goods sold expenditure. The meter accounting method change allows Avista, for income tax purposes, to deduct meter costs instead of capitalizing them if the per unit cost is less than $200.

[3] On December 31, 2020 in Case Nos. AVU-E-20-12 and AVU-G-20-07 Commission Staff filed comments supporting the Company's application as filed.

customers, which the Company is requesting approval to defer, and to begin amortization through separate tariff of those benefits concurrent with the effective date of this GRC. As explained later in my testimony, approval in all three of Avista's jurisdictions (Idaho, Washington and Oregon) to make this change is required, and any changes need to be adjusted concurrently with a GRC, as the methodology change has significant impact on both tax credits and rate base. The proposed amortization by the Company of the electric tax benefits ($31.3 million), beginning September 1, 2021 through separate "Tax Customer Credit" Tariff Schedule 76 (electric) of $24.783 million, offsets the Company's base electric rate relief requested in its entirety for Rate Year 1 (September 1, 2021) until approximately November 30, 2022. The result is no billed impact to electric customers for the Rate Year 1 increase. Customers would, however, see a bill increase for Rate Year 2, effective September 1, 2022 of 3.5% or $8.722 million.

For natural gas customers, the Company proposes to begin amortizing the natural gas tax benefits ($12.1 million) beginning September 1, 2021 over a 10-year period, through separate "Tax Customer Credit" Tariff Schedule 176 (natural gas) of approximately $1.226 million annually. This would offset the slight increase in Rate Year 1 ($52,000) and result in an overall reduction for natural gas customers of approximately 1.8% at that time on a billed basis. For Rate Year 2, as discussed later in my testimony, the Company proposes to amortize its "Natural Gas Deferred Depreciation Expense" balance of approximately $900,000 (as of August 31, 2021)[4], for one-year effective September 1, 2022 through

[4] The available "Natural Gas Deferred Depreciation Expense" balance of approximately $900,000 is a result of the Company deferring the benefit of reduced natural gas depreciation expense recorded on its books of record, but not yet reflected in its natural gas customer rates, for the period December 1, 2019 through August 31, 2021 (estimated), per Order No. 34276 in Case Nos. AVU-E-18-03 and AVU-G-18-02 (see Stipulation and Settlement at page 9, para. 14).

August 31, 2023, offsetting the proposed $950,000 increase through Separate "Deferred Depreciation Credit" Tariff Schedule 177. Customers would therefore see a slight bill impact effective September 1, 2022 of 0.1%.

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

A. Yes. I am sponsoring Exhibit No. 5, 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 December 31, 2019 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, 2021 through August 31, 2022) and Rate Year 2 (September 1, 2022 through August 31, 2023). The exhibits also show the calculation of the general revenue requirement, the derivation of the Company's overall proposed rate of return, the derivation of the net-operating-income-to-gross-revenue-conversion factor, and the specific pro forma adjustments proposed in this filing for each Rate Year 1 and Rate Year 2.

Q. Would you please summarize your direct testimony?

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

- The Company is requesting a Two-Year Rate Plan with a Rate Year 1 <u>electric</u> base rate relief of $24.783 million, or 10.1%, effective September 1, 2021. This is before the effect of the Tax Customer Credit Tariff Schedule 76 (electric). The Company is also requesting a Rate Year 2 electric base rate relief of $8.722 million or 3.2%, effective September 1, 2022.

- The Company is requesting a Two-Year Rate Plan with a Rate Year 1 <u>natural gas</u> base rate relief of $52,000, or 0.1%, effective September 1, 2021. This is before the effect of the Tax Customer Credit Tariff Schedule 176 (natural gas). The Company is requesting a Rate Year 2 natural gas base rate relief of $0.95 million or 2.2%, effective September 1, 2022. This is before the effect of the Deferred Depreciation Tariff Schedule 177.

- The Company has pro formed in this case capital additions for the period January 1, 2020 through August 31, 2023, including certain specific large and distinct capital projects related to joining the Western Energy Imbalance Market ("EIM"), the Company's Wildfire Resiliency Plan, and Colstrip Units 3 and 4. These capital additions, along with changes in power supply, are the main driver of the Company's request for rate relief.

- The Company has included a proposal to establish a Wildfire Balancing Account to track wildfire expenses over the 10-year life of the Wildfire Resiliency Plan.

- On October 30, 2020, the Company filed its Tax Accounting Application (Case Nos. AVU-E-20-12 and AVU-G-20-07), requesting authorization to change its accounting for federal income tax expense from a normalization method to a flow-through method for certain plant basis adjustments, including Industry Director Directive No. 5 (IDD #5), and meters. If approved by the Idaho, Washington and Oregon Commissions, the Company would record an immediate accumulated deferred income tax (ADIT) benefit of approximately $150.5 million on a system basis. That equates to $31.3 million for Idaho electric operations and $12.1 million for Idaho natural gas operations. Beginning in 2021, the on-going annual incremental deferred Idaho ADIT benefits to be deferred is estimated to be approximately $3.5 million for Idaho electric and $1.4 million for natural gas.

- Concurrent with the Rate Year 1 effective date of this GRC, the Company proposes to return to customers the Tax ADIT benefit (if approved), beginning September 1, 2021 through separate Tariff Schedules 76 (electric) and 176 (natural gas), titled "Tax Customer Credit" of $24.783 million for electric and $1.226 million for natural gas - <u>offsetting</u> the Company's requested <u>electric</u> base rate relief over approximately 15 months (1¼ years) - resulting in no billed impact to electric customers; and <u>reducing</u> current <u>natural gas</u> billed rates by approximately 1.8%. The natural gas tax benefit amortization is proposed over 10-years.

- Concurrent with the Rate Year 2 natural gas effective date of September 1, 2022, the Company proposes to return to customers the Deferred Depreciation Expense balance of approximately $900,000 (over 1-year), through separate Tariff Schedule 177 (natural gas), titled "Deferred Depreciation Credit," resulting in an overall 0.1% bill impact to natural gas customers.

II. COMBINED REVENUE REQUIREMENT SUMMARY – TWO-YEAR RATE PLAN: SEPTEMBER 1, 2021 THROUGH AUGUST 31, 2023

Q. Please describe the Company's Two-Year Rate Plan proposed for the period September 1, 2021 through August 31, 2023.

A. The Company is proposing a Two-Year Rate Plan for the period September 1, 2021 through August 31, 2023. For both electric and natural gas, the Company is proposing an increase for Rate Year 1 effective September 1, 2021 (hereafter "RY1"), and Rate Year 2 effective September 1, 2022 (hereafter "RY2"). The Company is proposing a Two-Year Rate Plan to avoid annual rate cases in its Idaho jurisdiction, providing benefits to all stakeholders. It provides benefits to our customers by providing a level of rate certainty over this two-year period; relief to all stakeholders – customers, the Commission and its Staff, intervenors, and the Company - from the administrative burdens and costs of litigation of annual general rate cases; and to Avista by providing a two-year window to manage its business in order to have an opportunity to achieve a fair rate of return.[5]

Q. Please elaborate on the benefits of a reasonable 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 year 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

[5]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 increasing corporate tax rates as espoused by the Biden administration, or new safety or reliability requirements imposed by regulatory agencies.

have a reasonable opportunity to earn its allowed rate of return. But if the first-year revenue requirement is insufficient, that insufficiency will persist.

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

A. After considering all standard Commission Basis adjustments, as well as additional pro forma and normalizing adjustments, the pro forma electric and natural gas rates of return ("ROR") for the Company's Idaho jurisdictional operations are 5.15% and 7.28%, respectively for RY1, ending August 31, 2022. After considering additional incremental pro forma adjustments for RY2, ending August 31, 2023, the pro forma electric and natural gas ROR are 4.51% and 6.87%, respectively. These return levels, especially for electric operations, are well below the Company's requested rate of return of 7.30%.[6] Table No. 1 below provides a summary of the RY1 and RY2 Rates of Return per the pro forma studies versus that proposed by the Company.

Table No. 1 – Rate of Return before Rate Relief

Two Year Rate Plan Rate of Return			
Service	RY1 Pro Forma	RY2 Pro Forma	Proposed
ID Electric	5.15%	4.51%	7.30%
ID Natural Gas	7.28%	6.87%	7.30%

The incremental revenue requirement necessary to give the Company an opportunity to earn its requested ROR in RY1 is $24,783,000 (10.1% base) for its electric operations, and $52,000 (0.1% base) for its natural gas operations, both prior to the effect of Schedules 76 (electric) and 176 (natural gas). The net impact to electric and natural gas customers

[6] Current authorized ROR is 7.35% for electric and 7.61% for natural gas.

after taking into consideration Tariff Schedules 76 (electric) and 176 (natural gas), is no electric bill impact and a reduction in natural gas bills of approximately 1.8% for RY1 (effective September 1, 2021).

The incremental revenue requirement necessary to give the Company an opportunity to earn its requested ROR in RY2 is $8,722,000 (3.2% base) for its electric operations, and $950,000 (2.2% base) for its natural gas operations, prior to the effect of Schedule 177. The impact to natural gas customers after taking into consideration Tariff Schedule 177 is a slight increase of under 0.1% for natural gas customers for RY2 (effective September 1, 2022).

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 & Percentage Increases				
Service	**RY1**		**RY2**	
	Revenue	**Base %**	**Revenue**	**Base %**
ID Electric	**$ 24,783**	**10.1%**	**$ 8,722**	**3.2%**
ID Natural Gas	**$ 52**	**0.1%**	**$ 950**	**2.2%**

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. The Company's last authorized rate of return for its Idaho electric operations was 7.35%, effective December 1, 2019, per Case No. AVU-E-19-04. The last authorized rate of return for its Idaho natural gas operations was 7.61%, effective January 1, 2018, per Case No. AVU-G-17-01.

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

A. The primary factors 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, electric net power supply expenses also contribute significantly to the incremental electric revenue requirement. Other changes impacting the Company's revenue requirement requests relate to increases in distribution, operation and maintenance (O&M), and administrative and general (A&G) expenses for both electric and natural gas operations, compared to current authorized levels.

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

A. Looking at the changes to "gross" plant in service for RY1, Idaho "gross" plant increases by approximately $133.9 million for electric, and approximately $65.1 million for natural gas, as compared to what is currently embedded in base retail rates[7]. For RY2, "gross" plant increases by approximately $79.8 million for electric, and approximately $9.4 million for natural gas, as compared to RY1. A breakdown of the incremental electric and natural gas gross plant additions for each year shown in Table No. 3 is as follows:

[7] Current embedded base retail rates include most net plant additions through December 31, 2019 for electric and December 31, 2017 for natural gas base rates.

Table No. 3 – Gross Plant Additions

Gross Plant Additions (000s)			
	Electric		Total Over
Investment	**RY1**	**RY2**	**2-YR Plan**
Generation/Transmission	$ 66,651	$ 47,009	$ 113,660
Distribution	$ 57,053	$ 27,577	$ 84,630
General & Intangible	$ 10,233	$ 5,216	$ 15,449
Total Electric Gross Additions	$ 133,937	$ 79,802	$ 213,739
	Natural Gas		**Total Over**
Investment	**RY1**	**RY2**	**2-YR Plan**
Distribution	$ 56,961	$ 7,848	$ 64,809
General & underground Storage	$ 8,146	$ 1,545	$ 9,691
Total Natural Gas Gross Additions	$ 65,107	$ 9,393	$ 74,500

The specific 2020 through August 2023 pro forma capital expenditures undertaken by the Company to expand and replace its generation, transmission, distribution and general facilities are discussed further by Company witnesses Mr. Thackston regarding production investment (including the Company's investment in Colstrip Units 3 and 4), Ms. Rosentrater regarding transmission, distribution and general investment, Mr. Kensok regarding the costs associated with Avista's IS/IT projects, Mr. Howell regarding Wildfire Plan investments, Mr. Magalsky regarding customer technology projects, and Mr. Kinney regarding Energy Imbalance Market (EIM) investments.

Company witness Ms. Schultz 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.[8]

[8] With the exception of the Pro Forma Colstrip Unit 3 and 4 investment and regulatory amortization included in Pro Forma Adjustments 3.14 and 22.07, which are discussed later in my testimony. The Colstrip Unit 3 and 4 generation capital additions are discussed and sponsored by Mr. Thackston.

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

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 $7.1 million ($21.6 million on a system basis) from the level currently included in base rates. This increase in expense is primarily due to the increase in the price of natural gas.[9] In addition, power supply expenses are higher by $3.6 million (of the $7.1 million) as a result of the inclusion of the Palouse and Rattlesnake wind power purchase agreements (PPA), which are currently tracked through the Company's Power Cost Adjustment (PCA).

In addition, as discussed by Company witness Mr. Schlect, effective with RY1, the level of Idaho's share of pro forma transmission revenues decreased $145,000 ($421,000 on a system basis), and the level of Idaho's share of transmission expenses decreased $234,000 ($681,000 on a system basis), versus that currently included in base rates. The net reduction in transmission revenues and expenses, decreases Idaho's share of transmission net costs by $89,000 versus that currently included in base rates. Therefore, the net change in power supply and transmission revenues and expenses result in an overall net increase in electric revenue requirement of $7.1 million in RY1.

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 mainly due, in part, to changes in costs associated with the

[9] As described by Mr. Kalich, the average AECO price for the pro forma period in this case is $2.09 per dekatherm, up more than 71% from $1.22 per dekatherm in the Company's prior GRC, Docket AVU-E-19-04.

Company's Wildfire Plan expenses and increases in insurance related to higher premiums, as a result of wildfires across the country. In addition, for both electric and natural gas operations, other increases are a result of increases in labor and benefits, as well as increases in information services/information technology (IS/IT) expenses associated with contractual agreements (necessary to support such costs as cyber and general security, emergency operations readiness, operations support, for example).

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 2019 test year.

III. DERIVATION OF TWO-YEAR RATE PLAN REVENUE REQUIREMENT

Test Period for Ratemaking Purposes

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

A. The test period being used by the Company is the twelve-month period ending ("12ME") December 31, 2019, presented on a 12ME August 31, 2022 and August 31, 2023 pro forma basis. Current authorized electric rates, effective December 1, 2019, were based upon the 12ME December 31, 2018 test year utilized in case AVU-E-19-04, adjusted on a pro forma basis. Current authorized natural gas rates, effective January 1, 2019, were based upon the 12ME December 31, 2016 test year utilized in the Two-Year Rate Plan, per case AVU-G-17-01, adjusted on a pro forma basis.

Q. Why is the Company using the twelve-month period ending 2019 as its test period, versus a partial or calendar-year 2020 twelve-month period?

A. The 12ME December 31, 2019 test period we believe is the most representative of normal operating conditions. The use of a test period that includes any portion of 2020 is not representative, as it was impacted by the COVID-19 pandemic.

Revenue Requirement – Rate Year 1 (RY1) & Rate Year 2 (RY2)

Q. Would you please explain what is shown in Exhibit No. 5, Schedules 1 and 2?

A. Yes. Exhibit No. 5, 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 page 1 of Exhibit No. 5, Schedules 1 and 2, show December 31, 2019 actual operating results and components of the average-of-monthly-average (AMA) rate base as recorded[10]; 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 7.30% rate of return for RY1. Column (f) reflects RY1 pro forma operating results with the requested increase of $24,783,000 for electric and $52,000 for natural gas.

Page 2 of Exhibit No. 5, Schedules 1 and 2, show similar columns starting with RY1 (09.2021 effective) pro forma results (equal to column (d) on page 1 of Exhibit No. 5, Schedules 1 and 2), reflecting operating results and components of rate base for RY1 results,

[10] Actual plant rate base (cost, accumulated depreciation (A/D) and associated deferred federal income taxes ("DFIT") uses the 2019 AMA balances. Plant rate base is adjusted to 08.2021 AMA basis for RY1, and 08.2022 AMA basis for RY2, with restating and pro forma adjustments.

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 (09.2022 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 7.30% rate of return for RY2. Column (g) reflects RY2 pro forma operating results with the requested increases of $8,722,000 for electric and $950,000 for natural gas, above that requested in RY1.

Q. Would you please explain page 3 of Exhibit No. 5, Schedules 1 and 2?

A. Yes. Page 3 of Exhibit No. 5, Schedule 1, shows the RY1 and RY2 revenue requirement calculations for electric of $24,783,000 and $8,722,000, respectively. Page 3 of Exhibit No. 5, Schedule 2, shows the RY1 and RY2 revenue requirement calculations for natural gas of $52,000 and $950,000, respectively.

Q. What does page 4 of Exhibit No. 5, 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 7.30%. Company witness Mr. Thies discusses the Company's proposed rate of return and the pro forma capital structure utilized in this case, while Company witness Mr. McKenzie provides additional testimony related to the appropriate return on equity for Avista.

Q. Would you now please explain page 5 of Exhibit No. 5, Schedules 1 and 2?

A. Yes. Page 5 shows the derivation of the net-operating-income-to-gross-revenue-conversion factor of 0.749719. The conversion factor includes uncollectible accounts receivable, Commission fees and Idaho State income taxes. Federal income taxes are reflected at 21%.

Q. Now turning to pages 6 through 12 for electric (Schedule 1), and pages 6 through 11 for natural gas (Schedule 2), of your Exhibit No. 5, please explain what those pages show.

A. Yes. Page 6 begins with actual operating results and rate base for the test period in column (1.00). Individual Commission Basis normalizing and restating adjustments that are standard components of general rate case filings begin in column (1.01) and continue through column (2.13) on page 8 for electric, and column (2.10) on page 7 for natural gas.

For <u>electric</u>, Exhibit No. 5, Schedule 1, individual pro forma adjustments for RY1 begin in column (3.00P) on page 9 and go through column (3.15) on page 10, with the "RY1 09.2021 FINAL TOTAL" column on page 10 representing the total pro forma operating results and net rate base for the RY1 pro forma period (effective 09.2021). Page 11 of Exhibit No. 5, Schedule 1, includes all RY2 pro forma adjustment columns (22.01) through (22.08), with the "RY2 09.2022 FINAL TOTAL" and "RY2 INCREMENTAL 09.2022I FINAL TOTAL" columns, representing the total pro forma operating results and net rate base for the RY2 pro forma period (effective 09.2022), and the incremental balances above the RY1 pro forma rate year.

For <u>natural gas</u>, at Exhibit No. 5, Schedule 2, individual pro forma adjustments for RY1 are listed on page 8, column (3.01) through page 9, column (3.12), with the "RY1 09.2021 FINAL TOTAL" column on page 9 representing the total pro forma operating results and net rate base for the RY1 pro forma period (effective 09.2021). Page 10 of Exhibit No. 5, Schedule 2, includes all RY2 pro forma adjustment columns (22.01) through (22.05), with the "RY2 Rate Change Total 09.2022 FINAL TOTAL" and

"INCREMENTAL 09.2021I Above 09.2021 TOTAL" columns, representing the total pro forma operating results and net rate base for the RY2 pro forma period (effective 09.2022), and the incremental balances above the RY1 pro forma rate year.

Finally, turning to page 12 of Exhibit No. 5, Schedule 1 (electric), and page 11 of Exhibit No. 5, Schedule 2 (natural gas), these pages are shown for illustrative purposes only. As shown in the first column of both Schedules 1 and 2, the first column reflects the RY1 base rate change and total pro forma operating results and rate base for the RY1 pro forma test period. The last two columns, however, show for <u>illustrative purposes</u>, the impact of the proposed Tax Customer Credit Tariff Schedules 76 (electric) and 176 (natural gas), returning the Tax benefit dollars to customers starting in RY1, as proposed by the Company, and discussed later in my testimony.

Q. Before moving on to describing the individual Commission Basis, restating and pro forma adjustments, please state the overall impact to customers including the impact of Tariff Schedules 76 and 176.

A. For electric, as shown in the final column on page 12 of Exhibit No. 5, Schedule 1, effective September 1, 2021 the overall bill impact to customers of the proposed RY1 base increase, offset by the return of the proposed tax benefit through the separate Tax Customer Credit Tariff Schedule 76, will result in <u>no bill impact</u> to customers. For natural gas, as shown on page 11 of Exhibit No. 5, Schedule 2, effective September 1, 2021 the overall bill impact to customers of the proposed RY1 base increase, offset by the return of the proposed tax benefit through the separate Tax Customer Credit Tariff Schedule 176, will result in a <u>reduction in billed rates</u> of approximately 1.8%. (As discussed above, if approved as filed, the Tariff Schedules 76 / 176 and the amortization of these tax benefits, would be in place approximately one and one quarter (1¼) years for electric and ten (10) years for natural gas, or September 1, 2021 (concurrent with GRC effective date) through November 30, 2022 for electric and August 31, 2031 for natural gas. Company witness Mr. Miller discusses these Tariffs Schedules within his direct testimony.)

Not shown in Exhibit No. 5, Schedule 2, is the additional bill credit proposed by the Company, utilizing Tariff Schedule 177 "Deferred Depreciation Credit" effective September 1, 2022, concurrent with the RY2 base change, resulting in an overall 0.1% bill impact to natural gas customers. (Mr. Miller discusses in his direct testimony proposed Tariff Schedule 177, which would amortize the "Deferred Depreciation Credit" balance of approximately $900, 000 for the period September 1, 2022 through August 31, 2023.)

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-19-04 and AVU-G-17-01), unless otherwise noted. Columns following the Results of Operations column (1.00) reflect restating adjustments necessary to: restate the actual results based on prior Commission orders; reflect appropriate annualized expenses and rate base; correct for errors; or remove prior period amounts reflected in the actual results of operations. In addition to the explanation of adjustments provided herein, the Company has also provided workpapers, both in hard copy and electronic formats, outlining additional details related to each of the adjustments. A summary of each adjustment follows:

Electric Adjustment (1.01) and Natural Gas Adjustment (1.01) - **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 (Accelerated Cost Recovery System, or ACRS, and Modified Accelerated Cost Recovery, or MACRS) and bond refinancing premiums.

The effect of these adjustments on Idaho rate base is a reduction of $3,020,000 electric, and an increase of $548,000 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[11] is a reduction of $15,000 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 NOI impact. The net impact on a consolidated basis of this adjustment decreases Idaho electric rate base by $63,000 and increases NOI by $365,000. No adjustment is necessary for natural gas rate base, net income however, increases by $271,000.

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[11] 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.

Adjustments included in the Deferred Debits and Credits consolidated adjustment are those necessary to reflect restatements from 2019 actual results (included in column 1.00 "Per Results of Operations"), based on prior Commission orders as explained below.

- **Colstrip 3 AFUDC Elimination** is a reallocation of rate base and depreciation expense between jurisdictions. In Cause Nos. U-81-15 and U-82-10, the Washington Utilities and Transportation Commission (WUTC) allowed the Company a return on a portion of Colstrip Unit 3 construction work in progress (CWIP). A much smaller amount of Colstrip Unit 3 CWIP was allowed in rate base in Case No. U-1008-144 by the IPUC. The Company eliminated the AFUDC associated with the portion of CWIP allowed in rate base in each jurisdiction. Since production facilities are allocated on the Production/Transmission formula, the allocation of AFUDC is reversed and a direct assignment is made. The rate base adjustment reflects the average-of-monthly-averages amount for the test period. No adjustment from that recorded within results of operations is necessary.

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

- **Kettle Falls & Boulder Park Disallowances** reflect the Kettle Falls generating plant disallowance ordered by this Commission in Case No. U-1008-185 and the Boulder Park plant disallowance ordered by the IPUC in Case No. AVU-E-04-1. The IPUC disallowed a rate of return on $3,009,445 of investment in Kettle Falls, and $2,600,000 million of investment in Boulder Park. The disallowed investment, and related accumulated depreciation and accumulated deferred taxes are removed. These amounts are a component of actual results of operations.

- **Restating CDA Settlement Deferral** adjusts the net assets and DFIT balances associated with the 2008/2009 past storage and §10(e) charges deferred for future recovery recorded on a 2019 AMA basis and the annual amortization expense based on a ten-year amortization, as approved in Case No. AVU-E-10-01, to reflect rate period levels. This deferral expired on September 30, 2020, so these balances are removed. The effect on rate base and expense is a decrease of $31,000 to reflect the level of rate base and expense of $0 during RY1.

- **Restating Spokane River Deferral** adjusts the net asset and DFIT balances related to the Spokane River deferred relicensing costs as recorded on a 2019 AMA basis and the annual amortization expense based on a ten-year amortization as approved in Case No. AVU-E-10-01, to reflect rate period levels. This deferral expired on September 30, 2020, so these balances are removed. The effect on rate base and expense is a decrease of $6,000 to reflect the level of rate base and expense of $0 during RY1.

- **Restating Spokane River PM&E Deferral** adjusts the net asset and DFIT balances related to the Spokane River deferred PM&E costs as recorded on a 2019 AMA basis and the annual amortization expense based on a ten-year amortization as approved in Case No. AVU-E-10-01, to reflect rate period levels. This deferral expired on September 30, 2020, so these balances are removed. The effect on rate base and expense is a decrease of $27,000 to reflect the level of rate base and expense of $0 during RY1.

- **Restating Montana Riverbed Lease** 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 through 2021 as previously required, increasing expense by $39,000.

- **Weatherization and DSM Investment** includes in rate base the Sandpoint weatherization grant balance (FERC account 124.350). Beginning in July 1994 accumulation of AFUCE[12] ceased on Electric DSM and full amortization began on the balance based on the measure lives of the investment. Beginning in 1995 the amortization rates were accelerated to achieve a 14-year weighted average

[12] Allowance for funds used to conserve energy.

amortization period, which was completed in 2010. Remaining as an Idaho rate base item is the weatherization loan balance of approximately $59,000.

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

- **Lake Spokane Deferral Amortization** reflects the amortization expense included in 2019 as a result of the three-year amortization of the deferred costs related to improving dissolved oxygen levels in Lake Spokane. In Case No. AVU-E-13-06 (see Order No. 32917), the Company received approval of an Accounting Order to defer the costs related to the improvement of dissolved oxygen levels in Lake Spokane. In Order No. 32917 the Commission authorized the Company to defer and transfer Idaho's share of these costs (approximately $473,000) to FERC account 182.3 (Other Regulatory Assets) for later recovery, with no carrying charge. A four-year amortization of the deferral balance beginning January 1, 2016 through December 31, 2019 was approved in Case No. AVU-E-15-05. This portion of the adjustment removes the expiring amortization, reducing expense by $117,000.

- **Amortization of Project Compass Deferral (natural gas)** includes the 2019 amortization expense associated with the three-year amortization of 80% of the deferred natural gas revenue requirement amounts associated with the Company's Project Compass Customer Information System (Project Compass) for calendar year 2015. In Case No. AVU-E-14-05, the Commission approved an all-party settlement, in which the Parties agreed that eighty-percent (80%) of the revenue requirement associated with Project Compass during 2015, beginning the month the Project goes into service, would be deferred, without a carrying charge, for recovery in a future proceeding. This project was moved into service on February 2, 2015. An amortization of the deferral balance beginning January 1, 2016 was approved in Case No. AVU-E-15-05. This portion of the adjustment removes the expiring amortization expense included in the 2019 test year, reducing expense by $168,000.[13]

Finally, this adjustment removes non-reoccurring deferral expenses included in the 2019 test period associated with the AFUDC Equity DFIT Deferral expense for electric and natural gas, of $343,000 and $110,000, respectively; as well as the Natural Gas Depreciation

[13]After completion of the Company's revenue requirement it was determined that the Company had inadvertently failed to remove the expiring electric amortization. Correction of this error would reduce amortization expense approximately $668,000 and reduce the Company's proposed revenue requirement by approximately $672,000.

Study Deferral of $81,000. In summary, as noted above, the net impact on a consolidated basis of this adjustment decreases Idaho electric rate base by $63,000 and increases NOI by $365,000. No adjustment is necessary for natural gas rate base, net income however, increases by $271,000.

Electric Adjustment (1.03) and Natural Gas Adjustment (1.03) - **Working Capital**, restates the working capital balance reflected in the Company's Results of Operations column (1.00) on a 12ME December 31, 2019 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 general rate case, Case No. AVU-E-19-04, and was used for both electric and natural gas results. As discussed in electric Case No. AVU-E-19-04, as a result of the Company's Washington general rate case (Dockets UE-170485 and UG-170486), the Company agreed to two changes that better reflect the level of working capital for Avista as follows: 1) reclassified certain interest-bearing accounts to investments and 2) changed the methodology for allocating certain working capital to non-utility operations. Prior to 2018, the investment in non-utility property was used to determine the allocation. Beginning in 2018, the updated method uses all non-rate base investments to determine the allocation. Reflecting these same changes consistently between Idaho and Washington allows for administrative efficiencies when recording working capital within the Company's jurisdictional results of operations. This method is consistent with that utilized in Case No. AVU-E-19-04. The net effect on Idaho results of reflecting these changes within Idaho's working capital methodology resulted in decreases to electric rate base of $1,671,000 and natural gas rate base of $432,000. This adjustment also decreases electric NOI by $8,000 and natural gas NOI by $2,000, due to the impact of debt interest.

Electric Adjustment (1.04) and Natural Gas Adjustment (1.04) - **Restate Capital 2019 EOP,** restates the capital investment and expenses associated with adjusting the 2019 AMA plant related balances to December 31, 2019 end-of-period (EOP) balances. Company witness Ms. Schultz sponsors this adjustment. As discussed by Ms. Schultz, this adjustment also reflects a correction to 2019 test period results to reflect an error discovered and corrected in 2020. Specifically, during 2020 it was discovered that the transfer-to-plant balance included in the 2019 historical test period for the Cabinet Gorge Gantry Crane Replacement project (completed in 2019), was overstated by approximately $1.4 million (system) in costs that should have been recorded to operating expense. This project is described by Mr. Thackston in his direct testimony. To correct for this error, Ms. Schultz restated Idaho electric EOP 2019 reducing rate base by approximately $473,000, reducing Idaho depreciation expense by $5,000, and increasing 2019 restated operating expense by approximately $478,000 ($1.4 million system).

The overall net effect of Adjustment (1.04) on Idaho rate base is an increase of $5,945,000 for electric and $3,871,000 for natural gas. The effect on Idaho NOI is a decrease of $327,000 electric and an increase of $19,000 natural gas related to the federal income tax effect of debt interest (and the correction to operating expense for electric).

Electric Adjustment (2.01) and Natural Gas Adjustment (2.01) - **Eliminate B & O Taxes**, eliminates the revenues and expenses associated with local business and occupation (B & O) taxes, which the Company passes through to its Idaho customers. The effect of this adjustment increases electric NOI by $4,000 and natural gas NOI by $2,000.

Electric Adjustment (2.02) and Natural Gas Adjustment (2.02) - **Uncollectible Expense**, restates the accrued expense to the actual level of net write-offs for the test period. The effect of this adjustment decreases electric NOI by $322,000 and increases natural gas NOI by $11,000.

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 increases electric NOI by $252,000 and natural gas NOI by $28,000.

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 $9,000 and natural gas NOI by $3,000.

Electric Adjustment (2.05) **FIT/DFIT/ITC/PTC Expense**, and Natural Gas Adjustment (2.05) **FIT/DFIT Expense**, adjusts the FIT and DFIT expenses calculated at 21% within Results of Operations, as needed, by reflecting the appropriate Schedule M items and jurisdictional allocation of these Schedule M items as compared to Results of Operations. In addition, for electric this adjustment adjusts for the appropriate level of production tax credits and investment tax credits on qualified electric generation if needed. The net tax credit adjustment decreases Idaho electric NOI by $9,000. For the natural gas adjustment, no adjustment is required.

Electric Adjustment (2.06) and Natural Gas Adjustment (2.06) - **SIT/SITC Expense**, adjusts Idaho State Income Tax (SIT) expense and Idaho State Investment Tax Credits (SITC) applicable to Idaho electric and natural gas operations as recorded. This approach is consistent with that approved in Case No. AVU-E-15-05. In addition, during 2019, the Company determined that normalization accounting for SITC, which was approved by the ID Commission beginning with 2016 results, had not been recorded. A prior period true up was recorded in April 2019 and proper accounting was recorded going forward. This adjustment removes the prior period true-up recorded in 2019. The effect on Idaho NOI is an increase of $883,000 for electric and $156,000 for natural gas.

Electric Adjustment (2.07) and Natural Gas Adjustment (2.07) - **Revenue Normalization**, is an adjustment taking into account known and measurable changes that include 1) revenue normalization which reprices customer usage using the current authorized base rates, 2) weather normalization, and 3) an unbilled revenue calculation. For the electric adjustment, schedules, such as, Schedule 91 Tariff Rider, Schedule 95 Optional Renewable Power and Schedule 59 Residential Exchange, are excluded from pro forma revenues, and the related amortization expense is eliminated as well. For the natural gas adjustment, all revenues and expenses associated with the Purchased Gas Cost Adjustment Schedule 150 have been removed from the Company's filing. In addition, revenues such as those associated with the temporary Gas Rate Adjustment Schedule 155 and Schedule 191 Tariff Rider are excluded from pro forma revenues, and the related amortization expenses are eliminated as well. Company witnesses Ms. Knox (electric) and Mr. Anderson (natural gas) sponsor these two adjustments. The effect of this adjustment decreases electric NOI $7,046,000 and increases natural gas NOI $413,000.

Electric Adjustment (2.08) and Natural Gas Adjustment (2.08) - **Miscellaneous Restating** removes a number of non-operating or non-utility expenses associated with advertising, dues and donations, etc., included in error, and removes or restates other expenses incorrectly charged between service and or jurisdiction. The net effect of this adjustment increases electric NOI by $20,000 and natural gas NOI by $17,000.

Electric Adjustment (2.09) and Natural Gas Adjustment (2.09) - **Restate Incentives,** restates actual O&M incentive compensation included in the Company's 2019 test period to reflect a six-year average (2014-2019) of actual payout amounts.

For <u>non-executive officers,</u> the six-year average of incentive compensation expense payout is $6.1 million (system) for O&M metrics designed to drive cost-control, and delivery of safe, reliable service with a high level of customer satisfaction. For <u>executive officers</u>, the six-year average expense payout of O&M metrics related to efficiencies in cost management (O&M cost-per-customer), customer service and reliability have averaged approximately $1.19 million (system) in operating expenses. Incentive compensation related to financial metrics are excluded from the Company's filing with expenses borne by shareholders. The net effect of this adjustment, including both non-executive and executive changes, decreases NOI by approximately $258,000 for electric and $66,000 for natural gas.

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

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

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

Q. Please briefly describe the Executive STIP.

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

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

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

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

A. The Long-Term Incentive Plan (LTIP) is comprised of two components, which serve two different purposes.[14] Performance Shares account for 75% of the plan with metrics related to Cumulative Earnings-Per-Share (CEPS) and Total Shareholder Return (TSR). The purpose for this portion of the plan is to provide a direct link to the long-term 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

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

peer group over a three-year period. Under the new design, two-thirds of the awards are contingent on TSR relative to our peers, and one-third is measured by our CEPS over a three-year period. The Company has excluded the costs associated with the Performance Share portion of the LTIP from the revenue requirement in this case.

Restricted Stock Unit (RSU) awards account for 25% of the LTIP and vesting is based on a continuation of service by the employee. The purpose for this portion of the plan is to provide an incentive for employees to remain with the Company. The long-term nature of large-scale utility projects spanning multiple years are completed more efficiently with experienced, consistent leadership. In addition, it is the Company's policy to promote from within when possible, preserving the values inherent in our culture that drive customer satisfaction, reliability of service, etc. Employees with a long tenure of employment with the Company are well versed in the Company's culture and tend to continue to cultivate the values embedded within Avista. The Company has included approximately $344,000 electric expense and $89,000 natural gas expense in this filing.

Q. Please continue explaining the remaining restating adjustments in Exhibit 5, Schedules 1 and 2.

A. The next adjustment is Electric Adjustment (2.10) - **Idaho PCA,** which removes the effects of the financial accounting for the Power Cost Adjustment (PCA). Under the PCA certain differences in actual power supply costs, compared to those included in base retail rates are deferred and then surcharged or rebated to customers in a future period. Revenue adjustments due to the PCA and the power cost deferrals affect actual results of operations and need to be eliminated to produce normalized results. Actual revenues and power supply costs are normalized in adjustments (2.07) Revenue

Normalization and (3.01P) Power Supply, respectively. The effect of this adjustment increases Idaho NOI by $143,000.

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 NOI by $26,000.

Electric Adjustment (2.12) – **Colstrip/CS2 Maintenance**. As approved in Order 32371 on September 30, 2011, (in Case Nos. AVU-E-11-01 and AVU-G-11-01), the Company deferred the non-fuel O&M costs associated with the Company's Colstrip and CS2 thermal generating plants. The deferral amount is the difference between actual costs and the authorized “Base O&M” costs for each respective year, included in base rates for the years 2016 – 2020 and estimated for 2021.

For calendar years 2013 through 2015, the authorized system “Base O&M” expense level (established in 2013 in AVU-E-12-08) was $14.4 million. Each year deferred costs were amortized over a three-year period. For 2016, in Case No. AVU-E-15-05, the system “Base O&M” cost was adjusted upward from $14.4 million to $20.4 million, to better reflect O&M expenses in the future based on a five-year average for the period 2012-2016, and will remain at this level going forward unless adjusted. Each prior year deferred costs are amortized over a three-year period. Adjusting expense to one-third of each amount deferred for calendar years 2018 through 2020, increases Idaho electric expense by approximately $908,000, and decreases NOI by $684,000.[15]

Electric Adjustment (2.13) and Natural Gas Adjustment (2.10) - **Restate Debt Interest**, restates debt interest using the Company's pro forma weighted average cost of debt on the Results of Operations level of rate base shown in column (1.00) only. The weighted average cost of debt is as provided in the testimony and exhibits of Mr. Thies. This adjustment results in a revised level of tax-deductible interest expense on actual test period rate base. The Federal income tax effect of the restated level of interest for the test period decreases electric NOI by $649,000 and natural gas NOI by $134,000.

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 8 of Exhibit No. 5 Schedule 1, and page 7 of 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 DJUSTMENTS

Q. Please explain the significance of the adjustments beginning at page 9 for Schedule 1 (electric) and page 8 for Schedule 2 (natural gas) of Exhibit No. 5.

A. The adjustments on pages 9 and 10 of Exhibit No. 5, Schedule 1, and page 8 and 9 of Exhibit No. 5, Schedule 2, are pro forma adjustments that will impact the RY1 pro

[15] See Pro Forma adjustment 22.07, which adjusts Colstrip/CS2 maintenance amounts reflected in RY1, to reflect one-third of each amount deferred for calendar years 2019 through 2021 to reflect Colstrip/CS2 maintenance amounts expected in RY2.

forma operating period. Included on page 11, Schedule 1 and page 10, Schedule 2 of Exhibit No. 5, are additional pro forma adjustments that will impact the RY2 pro forma operating period. These pro forma adjustments in RY1 and RY2 encompass revenue and expense items as well as additional capital projects, bringing the operating results and rate base to the final pro forma levels for the RY1 and RY2 rate years.

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

<u>RY1 (09.2021 – 08.2022) – Summary of Adjustments</u>

Q. Please explain each of the RY1 Pro Forma adjustments included in Exhibit No. 5, starting on page 9 of Schedule 1 and page 8 of Schedule 2.

A. The first adjustment, starting on Exhibit No. 5, page 9, 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 his testimony. This adjustment includes pro forma power supply related revenues and expenses to reflect the twelve-month period September 1, 2021 through August 31, 2022 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 (3.01P) calculates the Idaho jurisdictional share of those figures. The net effect of this adjustment increases electric NOI by $2,789,000.

Electric Adjustment (3.00T) - **Pro Forma Transmission Revenue/Expense,** was made under the direction of Mr. Schlect 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, 2021 through August 31, 2022. The net effect of this adjustment decreases electric NOI by $369,000.[16]

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 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

[16] After the completion of the Company's revenue requirement in this case, it was determined the change in transmission revenues in Pro Forma Transmission Revenues and Expenses Adjustment 3.00T included in Exhibit No. 5, Schedule 1 included an error. The Company will correct this error during the process of this case. Correcting this error increases transmission revenues $25,000 and decreases the Company's requested revenue requirement $26,000. This correction has no impact on the proposed system transmission revenues included in the Power Cost Adjustment base discussed by Mr. Schlect.

operational efficiencies by awarding variable pay for meeting pre-determined metrics;

- Promote a culture of safety;
- Pay competitively compared to others within our market;
- Reward outstanding performance; and
- Align elements of the incentive plans among all Company employees, including executive officers.

Each component is carefully considered within the overall package in order to provide total compensation which will be cost-effective for the Company, as well as, attract 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 adjustment (2.09) above) is designed to provide competitive compensation in the marketplace. The level of base pay is determined based on position qualifications such as level of education, professional designations or certifications, experience, roles and responsibilities, and within the market where we compete for talent. Avista participates in numerous confidential salary surveys provided by third-party consulting firms which compare Avista's pay programs and structure to other organizations in the utility industry, as well as other industries, regionally and nationally. Salary surveys are part of the input in the determination of salary increases and salary range updates (minimum, mid-point and maximum), as well as benchmarking jobs to market data. Avista benchmarks many jobs within the Company and reviews market data to determine if the salary range midpoints still accommodate the new estimated values established by the benchmarking process. Based on the information provided in these surveys, salary recommendations are presented to the independent Compensation Committee of the Board of Directors for their consideration and approval. The Compensation Committee can choose to grant higher or lower salary adjustments, based on the available market data.

The specific electric and natural gas adjustments**,** reflect changes to test period union and non-union wages and salaries, excluding executive salaries, which are handled separately in Pro Forma Adjustment (3.02). For non-union employees, the adjustment annualizes the impact of increases effective March 2019, and includes a 3.0% adjustment for increases which were effective March 2020. The Company has not had a final increase for non-union employees for 2021 approved (that will be in effect well before the start of the rate effective period), however the Board of Directors has approved a preliminary minimum salary increase of 3% based on 2020 salary planning surveys. The Company will update the adjustment should the actual approval be less than 3%. Union employee increases are made in accordance with contract terms to annualize the impact of the 3% increase in 2019 and reflect the 3% actual increase for 2020. The current contract with the IBEW Union 77 (Idaho/Washington) expires on March 25, 2021. The Company has included an estimated increase of 3% for 2021 in order to be consistent with non-union employees. The Company will update the contract agreement increase during the process of the case once it is available. In total, this adjustment represents an increase in expense of $1.94 million electric and $0.64 million natural gas. The effect of this adjustment decreases electric and natural gas NOI by $1,461,000 and $485,000, respectively.

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 February 2020. This salary level is allocated between Utility and Non-Utility based on 2019 levels actual percentages[17] (90% utility /10% non-utility). This adjustment also reflects the changes (retirements and additions) in officers and their impact on salary expense from 2019 to 2020. The impact of this adjustment reduces expense for electric by $141,000 and for natural gas by $37,000.

The Compensation Committee of the Board of Directors (Board) determined and approved the level of executive officer level of base salary effective March 2020, 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 electric and natural gas NOI by $106,000 and $28,000, respectively.

Electric Adjustment (3.03) and Natural Gas Adjustment (3.03) - **Pro Forma Employee Benefits**, adjusts the twelve-months ended December 31, 2019 Retirement Plans (401(k) and Pension), and Medical insurance for active employees and for those retired (post-retirement medical) to the expected amount for the rate effective period. Annually, the

[17] For those Executives who were new in 2019, the union/non-union percentages are estimated based on the previous (retired) Executives' actual allocation.

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 are summarized in Table No. 4 below:[18]

Table No. 4: Benefit Adjustment

Benefit Adjustment	System	O&M	ID Electric	ID Natural Gas
Medical	$ 6,200,705	$ 3,542,463	$ 770,336	$ 199,157
Retirement	(7,195,754)	(4,110,934)	(893,955)	(231,117)
Total	$ (995,049)	$ (568,471)	$ (123,619)	$ (31,960)

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

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

A. The Company's Retirement portion of the calculation adjusts the 401(k) expense and Pension Plan from the twelve-months ending December 31, 2019 to reflect what will be in effect during 2020, resulting in an overall <u>system expense reduction</u> of $4.5 million. 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

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

contributor to this decrease in expense is related to changes in asset value due to the actual return on assets for 2019 partially offset by changes in the discount rate and the expected long-term return on assets for 2020. 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 provided by our actuary for 2022.[19] We anticipate updates for 2021 and 2022 to be available sometime in the first quarter of 2021, and the Company will adjust pension expense at that time to reflect a prorated amount of 2021-2022 for the rate effective period.

In addition, the Company has made changes to the overall retirement plan, discussed below, resulting in an increase in 401(k) expense on a system basis of $355,000. The Company has proposed an increase of 6% consistent with proposed labor increases for 2021 and 2022 as discussed in Pro Forma Labor Non-Exec adjustment (3.01). Over the long term, we anticipate a decrease in pension expense will reduce overall retirement net expense over the long-term.

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

A. In October 2013, the Company revised the defined benefit pension plan such that, as of January 1, 2014, the plan is closed to all non-union employees hired or rehired on or after January 1, 2014.[20] All actively employed non-union employees that were hired prior

[19] The estimate for 2022 was used as the basis for the rate effective period.
[20] Changes were applicable to Local Union 659 (Oregon operations) effective April 1, 2014.

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. A defined contribution 401(k) plan replaced the defined benefit pension plan for all non-union employees hired or rehired on or after January 1, 2014. Under the defined contribution plan the Company will provide a non-elective contribution as a percentage of each employee's pay based on the age of the employee. This defined contribution is in addition to the existing 401(k) contribution where Avista matches a portion of the pay deferred by each participant. In addition to the above changes, the Company also revised our lump sum calculation for non-union retirees under the defined benefit pension plan to provide non-union participants who retire on or after January 1, 2014 with a lump sum amount equivalent to the present value of the annuity based upon applicable discount rates.

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 overage for medical, dental and vision as a portion of employee benefits. Annually, medical premiums[21] for the Company are estimated by an independent consultant, Mercer,[22] 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:

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

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

- 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. In this case, the primary contributor to the increase in expense is related to an increase in cost trend assumptions. We anticipate updates for 2021 to be available sometime in the first quarter of 2021, 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 <u>system</u> expense of $3.5 million.

As shown in Table No. 4 above, the overall net impact of changes in pension and medical expense on a system basis is a decrease of $568,000, or $124,000 Idaho electric and $32,000 Idaho natural gas. Therefore, the Pro Forma Employee Benefits adjustment increases NOI for electric by $93,000 and for natural gas by $24,000. Again, the Company will update the level of expense as soon possible during the process of the case, after receiving updated consultant information expected in early 2021.

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 2019 test year to include 2020 and 2021 known increases in expense. This adjustment includes the incremental costs primarily associated with <u>contractual agreements in place, pre-paid costs, or are the continuation of costs</u> for products and services that have increased beyond the 2019 historical test period associated with products and services, licensing and maintenance fees, and other costs for a range of information services programs. These incremental expenditures are necessary to support Company cyber and general security, emergency operations readiness, electric and natural gas facilities and operations support, and customer service. Mr. Kensok sponsors this adjustment and provides more information within his testimony. The effect of this adjustment decreases NOI by $638,000 for electric and by $165,000 for natural gas.[23]

Electric Adjustment (3.05) and Natural Gas Adjustment (3.05) – **Pro Forma Property Tax**, restates the 2019 test period accrued levels of property taxes to the RY1 rate period level using the most current information. As can be seen from my workpapers provided with the Company's filing, the property on which the tax is calculated is the property value as of December 31, 2020 at existing tax rates, reflecting the level of expense

[23] See Pro Forma adjustment 22.05, which adjusts Pro Forma IS/IT Adjustment 3.04 amounts reflected in RY1, to include incremental 2022 IS/IT expenses planned in RY2 above RY1 levels.

the Company will experience during 2021 and the RY1 rate period. The net effect of this adjustment decreases NOI by $592,000 electric and $110,000 natural gas.[24]

Electric Adjustment (3.06) and Natural Gas Adjustment (3.06) – **Pro Forma Insurance Expense,** reflects increases from test period 2019 insurance expense for general liability, directors and officers ("D&O") liability, and property insurance to the level of insurance expense the Company is expecting in 2020 and during RY1. New invoicing in December 2020 for the Company's general and property insurance premiums, and estimated March 2021 for D&O insurance premiums were used to determine the planned RY1 level of expense. The Company will update any estimated amounts included as soon as the actual invoices are available. The effect of this adjustment decreases NOI by $856,000 for electric and by $75,000 for natural gas.

Q. Please summarize the main cause for the increased level of insurance expense included in the Company's case, compared to that experienced in the 2019 test period.

A. Although in recent years insurance premiums have been held flat or slightly decreased, starting in late 2019 insurance companies have started raising premiums, some significantly, due to an increase in claim frequency and severity. Increases in general liability insurance premiums above and beyond industry wide increases are a result of recent wildfire activity, combined with insurers' continuing wildfire losses and perceived increase of wildfire risk throughout the western United States. Avista also expects significant increases in its Property and D & O insurance premiums at least through 2022 as insurer

[24] See Pro Forma adjustment 22.03, which adjusts Pro Forma Property Tax Adjustment 3.05 amounts reflected in RY1, to include incremental 2022 Property Tax expenses planned in RY2 above RY1 levels.

look to bring collected premiums in line with increases in losses.

With regards to general liability, the excess liability insurance marketplace started to see significant premium increases in 2019 due to an increase in loss costs for the industry primarily attributable to the frequency of large jury settlements. Given this, Avista expected to see premium increases due to wildfire exposure in its territory and across the Pacific Northwest. The occurrence of the September 7, 2020 wildfire event, coupled with the occurrence of prior fires in Avista's service territory, resulted in higher premium increases for 2021.

With regards to property insurance, the property insurance market in the latter half of 2018 began to pivot away from several years of declining rates (2013-2017) to one where premium increases will be the new norm through at least 2022. While premiums continued to decrease over the prior period, claim activity did not decrease, resulting in ever decreasing profitability for insurance companies. This problem became compounded when the industry experienced two of the biggest catastrophic loss years in the history of the industry in 2017 and 2018. This triggered an industry-wide move for insurers to start to seek property insurance premium increases in order to return this line of business to profitability. Avista had a 18.5% increase in property insurance premiums at its 12/1/19 renewal. Industry-wide, premiums have continued to increase, often at a monthly rate, since that time. Avista's insurance broker has indicated that U.S. property insurance companies will be seeking a minimum premium increase of approximately 25% annually over the next couple of years in order to return their property lines of business to profitability.

Finally, with regards to D & O insurance, this insurance has shared the same history of declining premiums during a period of increasing loss activity. Insurance companies industry-wide have seen increased losses driven by specific large loss events, merger objection lawsuits, an increase in securities class-action suits, general increases in claims frequency and higher defense costs. Going forward, insurers see additional risk in expected claims. Based on these increased risks in the industry, Avista expects a blended rate increase of 11% at its 3/31/2021 renewal.

The percentage of the general liability premium <u>increase</u> discussed above attributable to wildfire risk is estimated by the Company to be approximately 39.21%. Therefore, 39.21% of this premium increase will be expensed beginning January 2021 directly to electric operations, allocated between Idaho and Washington. Whereas, consistent with prior years, all other insurance expenses are allocated to all services and jurisdictions as a common cost.

The overall increase in insurance expense included in this case above 2019 test period levels is an increase of $4.3 million (system). The portions allocated to Idaho result in $1.1 million Idaho electric and $121,000 Idaho natural gas. The Company will update any estimated insurance premium levels once new invoices are received March 2021 and will update these estimated amounts during the process of this case. In summary, as noted above, the current effect of this adjustment decreases NOI by $856,000 for electric and by $75,000 for natural gas.

Electric Adjustment (3.07) and Natural Gas Adjustment (3.07) – **Pro Forma ARAM DFIT,** adjusts the electric and natural gas ARAM DFIT amortization expense included in the 2019 test period to reflect the level of ARAM DFIT amortization expense expected for the rate effective period. As a result of the December 31, 2017 Tax Cuts and Jobs Act (TCJA), Avista had an electric plant excess ADFIT balance (Regulatory Liability) of approximately $208.3 million as of December 2017. In accordance with the TCJA's Average Rate Assumption Method (ARAM), the Company is required to reverse (i.e. normalize) these "protected" balances over the depreciable lives of the capital assets that created the ADFIT. The Company estimates the ARAM for Avista results in an amortization period of approximately 36 years from December 31, 2017 or a remaining approximate 32 years from September 1, 2021. This long-term tax benefit was included in Idaho electric and natural gas billed rates through Tariff Schedule 72 (electric) and 172 (natural gas) effective June 1, 2018, in Case No. GNR-U-18-01 (Order No. 34070 Avista Corporation), and Idaho electric base rates effective December 1, 2019, in Case No. AVU-E-19-04).[25] The amortization of this balance over 36 years provides a tax benefit to customers (reduction in rates) of approximately $2.4 million Idaho electric and $0.4 million Idaho natural gas. The annual excess plant DFIT amortization benefit will vary annually as the IRS ARAM is not calculated on a straight-line basis. This adjustment updates the DFIT amortization expenses in RY1. The effect of this adjustment increases electric NOI by $236,000 and decreases natural gas NOI by $19,000.[26]

Q. Please now turn to page 10 of Schedule 1 (electric) and page 9 of

[25] Electric Schedule 72 expired November 30, 2019 with the effect of new base rates on December 1, 2019 reflecting the long-term tax benefit. Natural Gas Tariff Schedule 172 will expire after the pendency of this case, expected August 31, 2021, with RY1 natural gas base rates reflecting the long-term tax benefit.

[26] If the Commission approves the Company's Tax Accounting Application filed October 30, 2020 (Case Nos. AVU-E-20-12 and AVU-G-20-07) requesting authorization to change its accounting for federal income tax expense from a normalization method to a flow-through method for certain plant basis adjustments, certain excess DFIT tax balances will be reclassed as non-protected and removed from the ARAM calculation. These removed balances would be available to be returned to customers over a shorter period as discussed in the Tax Accounting Application. Electric and natural gas Pro Forma ARAM Adjustments (3.07) would therefore need to be revised during the pendency of this general rate case to reflect those changes, lowering the annual ARAM tax amortization benefit.

Schedule 2 (natural gas) of Exhibit No. 5, and discuss the pro forma adjustments shown there.

A. Beginning on page 10 of Schedule 1 (electric) and page 9 of Schedule 2 (natural gas) of Exhibit No. 5 are Electric Adjustment (3.08) and Natural Gas Adjustment (3.08) – **Pro Forma Capital Additions 2020 EOP**, which reflect 2020 capital additions[27] together with the associated AD and ADFIT at a December 31, 2020 EOP basis. This adjustment also includes associated depreciation expense for these 2020 additions, as well as, incremental annualized depreciation expense on plant-in service at December 31, 2019. In addition, the plant-in-service at December 31, 2019 EOP was adjusted to a December 31, 2020 EOP basis. Finally, 2020 retirements on plant-in-service at December 31, 2019 were included reducing expense and the overall impact of this adjustment. Ms. Schultz describes this adjustment in detail within her testimony. The effect of this adjustment increases Idaho rate base $20,464,000 electric and $2,671,000 natural gas. The effect of this adjustment on Idaho NOI is a decrease of $4,536,000 electric and $907,000 natural gas.[28]

Electric Adjustment (3.09) and Natural Gas Adjustment (3.09) – **Pro Forma Capital Additions 08.2021 EOP**, reflects January 1, 2021 through August 31, 2021 capital additions[29] together with the associated AD and ADFIT at an August 31, 2021 EOP basis.

[27] For each of the periods 2020 through August 31, 2023, distribution-related capital expenditures associated with connecting new customers to the Company's system was excluded. An increase in revenues from growth in the number of customers from the historical test year to the RY1 and RY2 rate periods are excluded, therefore, the growth in plant investment associated with customer growth was also excluded.

[28] As discussed by Ms. Schultz, after completion of the revenue requirement proposed in this filing, it was determined that the Customer Facing Technology project "Energy Management (Budget) Alerts", totaling approximately $790,000 total transfer-t-plant in 2020 (system), was a Washington only project, as discussed by Mr. Magalsky. Therefore, this project should have been excluded from Pro Forma Capital Additions 2020 EOP Adjustment (3.08) in this filing. A portion of this project, however, was allocated to Idaho electric and natural gas in error. Correction of this error will reduce Idaho net rate base by approximately $153,000 for electric and $41,000 for natural gas. This will also result in a reduction to the Company's proposed Idaho electric and natural gas revenue requirements of approximately $48,000 and $13,000, respectively.

[29] See footnote 25.

This adjustment also includes associated depreciation expense for these additions. In addition, the plant-in-service at December 31, 2020 EOP was adjusted to an August 31, 2021 EOP basis. Finally, 2021 retirements through August 31, 2021 on plant-in-service at December 31, 2020 were included, reducing expense and the overall impact of this adjustment. Ms. Schultz describes this adjustment in detail within her testimony. The effect of this adjustment increases Idaho rate base $1,467,000 electric and $1,493,000 natural gas. The effect of this adjustment on Idaho NOI is a decrease of $1,869,000 electric and $298,000 natural gas.[30]

Electric Adjustment (3.10) and Natural Gas Adjustment (3.10) – **Pro Forma Capital Additions 08.2022 AMA**, reflects September 1, 2021 through August 31, 2022 capital additions[31] together with the associated AD and ADFIT at an August 31, 2022 AMA basis. This adjustment also includes associated depreciation expense for these additions. In addition, the plant-in-service at August 31, 2021 EOP was adjusted to an August 31, 2022 AMA basis. Finally, 2022 retirements through August 31, 2022 on an AMA basis, on prior plant-in-service were included, reducing expense and the overall impact of this adjustment. Ms. Schultz describes this adjustment in detail within her testimony. The effect of this adjustment increases Idaho rate base $22,341,000 electric and $1,079,000 natural gas. The effect of this adjustment on Idaho NOI is an increase of $452,000 electric and $69,000

[30] As discussed by Ms. Schultz, after completion of the revenue requirement proposed in this filing, the Company identified approximately $26 million (system) of additional 2021 transfers to plant related to variances between final 2020 expected amount and 2020 year-end CWIP. This will result in an increase to the Company's proposed Idaho electric and natural gas proposed revenue requirements of approximately $1,000,000 and $100,000, respectively.

[31] See footnote 25.

natural gas.[32]

Electric Adjustment (3.11) – **Pro Forma Operation & Maintenance (O&M) Offsets,** includes 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 costs and were discussed in the direct testimony of Ms. Rosentrater, with the capital asset with which the net offset relates. The net effect of this adjustment increases electric NOI by $42,000. As noted above, additional reductions in expense were reflected in Pro Forma Adjustments (3.08) through (3.10) (as well as pro forma adjustments (22.01) and (22.02)) with the inclusion of retirements in each electric pro forma capital adjustment. No further O&M reduction was included for natural gas operations in addition to the inclusion of retirements in each natural gas pro forma capital adjustment.

Electric Adjustment (3.12) and Natural Gas Adjustment (3.11) – **Pro Forma Fee-Free Amortization,** reflects the annual electric and natural gas expense associated with the "fee-free" payment expense expected during the rate year and the amortization expense of the "fee-free" payments approved for deferral as described below.

On January 13, 2016, Avista filed with the IPUC an application requesting an order authorizing accounting and ratemaking treatment of fees for credit and debit card payments made by residential customers. Avista asked to defer, for up to 36 months from the time the program went into effect, all fees paid by Avista related to offering a fee-free program for

[32] See RY2 pro forma additions included beyond RY1, included with Pro Forma Capital Additions Adjustments (22.01) and (22.02) described below. Also provided below is a summary of the revenue requirements of the specific large and distinct projects related to Wildfire, EIM, and Customer Experience investments discussed by Mr. Howell, Mr. Kinney and Mr. Magalsky, respectively, included in the Pro Forma Capital Additions Adjustments (sponsored by MS. Schultz) for RY1 and RY2 for ease of reference of these projects on an individual basis.

payment of bills by Idaho residential customers that use credit and debit cards. Avista also proposed that the deferred balance would be included in the Company's next general rate case and amortized over 24 months.

On April 1, 2016 the Commission issued Order No. 33494 in Case No. AVU-E-16-01 and AVU-G-16-01 approving Avista's application for an order authorizing accounting and ratemaking treatment of its residential fee-free payment program, including deferred accounting treatment of up to 36 months. However, the Commission ordered the amortization period was to be determined in the Company's next general rate case. The fee-free payment program was then successfully launched February 19, 2017.

As of November 30, 2019, for electric, and January 31, 2020, for natural gas, \$678,000 and \$475,000, respectively, of Idaho customer transactions through the fee-free payment program were deferred, for an Idaho total of \$1,153,000. With the conclusion of the electric general rate case (Docket AVU-E-19-04), the Company received approval to begin amortizing the electric deferred balance over three years beginning January 1, 2020.

In this proceeding, the Company is proposing to include "fee-free" payment expense expected during the rate year of \$405,000 for electric. In addition, the Company is proposing to include an amortization expense of \$146,000 of the electric "fee free" deferred balance. This amount is the result of amortizing the <u>remaining balance</u> (\$291,000) of "fee-free" payments deferred from February 2017 through November 30, 2019 (total deferred \$678,000).[33] Although in Case No. AVU-E-19-04, the Commission approved a three-year amortization period for the deferred electric balance of \$232,000 annually, the Company is

[33] Avista will have amortized approximately \$387,000 of the electric deferred "free fee" balance from January 1, 2020 through August 31, 2021. Leaving a balance of approximately \$291,000 at the start of the new rate period effective September 1, 2021.

proposing to extend that amortization eight months, lowering the annual amortization expense to $146,000 over the Two-Year Rate Plan, from September 1, 2021 through August 31, 2023.

For natural gas, the Company is proposing to include “fee-free” payment expense expected during the rate year of $265,000. In addition, the Company is proposing to include an amortization expense of $238,000 of the natural gas “fee free” deferred balance. The total deferred balance from February 2017 through January 31, 2020 totaled approximately $475,000. Consistent with electric, with regards to amortizing over the Two-Year Rate Plan the remaining electric deferred balance, the Company requests approval to amortize the natural gas deferred balance of $475,000 over two years starting September 1, 2021 through August 31, 2023.

In summary, for electric, the Company has included a total adjustment to expense of $551,000 (including $146,000 for the amortization of the deferred balance and approximately $405,000 for rate year expense). The net effect of this adjustment decreases electric NOI by $436,000. For natural gas, the Company has included a total adjustment to expense of $503,000 (including $238,000 for the amortization of the deferred balance and approximately $265,000 for rate year expense). The net effect of this adjustment decreases natural gas NOI by $392,000.[34]

Electric Adjustment (3.13) and the final RY1 Natural Gas Adjustment (3.12) – **Pro Forma Restate 2019 ADFIT,** reflects the updated ADFIT balances for the impact of the tax

[34] See Andrews’ workpapers at electric Adjustment 3.12 and natural gas Adjustment 3.11 for further adjustments between accounts, which have no impact on overall expense.

accounting method changes (updating the tax repairs adjustment[35] and including the Industry Director Directive No. 5 (IDD #5) and meters tax deductions), described by Mr. Krasselt, which were reflected in the Company's 2019 tax return filed in October 2020. The adjustment first restates the December 31, 2019 ADFIT balance for the impact of the 2019 tax return. The adjustment then pro forms the impact of these tax method changes for the estimated 2020 impact, factoring in the additional ADFIT that was pro formed in other previous adjustments described by me above. The overall effect of this adjustment decreases Idaho NOI by $74,000 for electric and $32,000 for natural gas. This adjustment also reduces total rate base by $15,082,000 for electric and $6,475,000 for natural gas.

Electric Adjustment (3.14) **Pro Forma Colstrip Amortization**, reflects the approved treatment (with one modification for transmission assets, described below) 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.[36] This adjustment also reflects the Company's proposal to include the Colstrip capital additions between January 1, 2020 and August 31, 2022, on an AMA basis in the Colstrip Regulatory Asset for recovery over its authorized amortization period.

Company witness Mr. Thackston sponsors the Colstrip capital additions testimony, describing the capital that has been included in this general rate case, including capital

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[35]Avista's largest basis adjustment has historically been tax repairs. Beginning in 2014, Avista changed its method of accounting as it relates to determining whether expenditures to maintain, replace, or improve various utility property were capitalized under § 263(a) or are deductible under § 162. Avista has elected to deduct these items for tax purposes while capitalizing them for book purposes. In 2020, Avista reexamined the tax repairs calculation and filed a change in accounting method with the IRS, under IRC § 481(a), to adopt a more detailed calculation.

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

additions between January 1, 2020 and August 31, 2023, for prudency review in this proceeding. This adjustment for RY1 includes capital additions between January 1, 2020 and August 31, 2022 and Adjustment 22.07 for RY2, described below, includes capital additions between September 1, 2022 and August 31, 2023.

The effect of this adjustment increases Idaho regulatory amortization expense by $338,000, increases depreciation expense by $3,000 and increases Colstrip net plant by $5,452,000. The net impact of this adjustment, therefore, increases Idaho electric rate base by $5,452,000 and decreases electric NOI by $230,000.

Q. Please provide a brief summary of the accounting treatment approved by the IPUC for Colstrip Units 3 and 4 in Order 34276 of Case No. AVU-E-18-03.

A. On March 19, 2019, per Order 34276 in Case No. AVU-E-18-03, the IPUC approved the Settlement Stipulation proposed by the Settling Parties, regarding Avista's recovery of Colstrip Units 3 and 4's undepreciated investment in Colstrip Units 3 and 4 and its asset retirement obligations (ARO) for Colstrip, assuming a remaining "useful life" of those units through December 31, 2027.[37] The IPUC approved the recovery of the undepreciated balance as follows:

- Maintain the current level of Idaho's share of depreciation expense of $2.475 million annually currently being recovered from customers through December 31, 2027.
- Use of $6.41 million (ID share) of "temporary" tax credits associated with Non-plant Excess ADFIT[38] to offset the total balance associated with the acceleration of depreciation/ARO costs on the current Colstrip Unit 3 and 4 assets.

[37] Prior to the "useful life" of 2027 for depreciation purposes approved in Case No. AVU-E-18-03, these units had been on a depreciation schedule of 2034 and 2036, respectively. No closure date was established for Colstrip Units 3 and 4 as a part of the Settlement agreement.
[38] The tax credits were made available by the provision of the Tax Cuts and Jobs Act (TCJA) that reduced the federal corporate tax rate from 35% to 21%.

- The remaining balance not recovered through depreciation will be recovered through the amortization of a Regulatory Asset (FERC Account No. 183.327 - Colstrip Regulatory Asset) and amortized over 34.75 years (beginning April 1, 2019) through 2053. The Regulatory Asset, net of accumulated deferred federal income taxes, will be included in rate base and will earn Avista's rate of return.[39]
- Prudency of any capital additions not yet in current rates are subject to review in future rate proceedings.

Q. Please discuss the Company's proposal in this case related to Colstrip transmission investment.

A. The Company originally included the transmission assets in its proposal to accelerate depreciation to 2027 and defer the excess amount of depreciation not included in customers' rates for recovery over 34 years. The Company has determined that the transmission assets will be functional if and when the Colstrip generating units are no longer functional. Therefore, the Company is proposing to remove the transmission assets from the Colstrip accounting that has been approved by the Commission.

As shown below in Table No. 5 below, removing the transmission investment from the Colstrip deferral accounting reduces the amortization expense by $125,000. The Company is proposing that the Colstrip transmission assets are depreciated using the depreciation rates approved for non-Colstrip transmission assets that was approved in the Company's most recent deprecation study (Case No. AVU-E-18-03).

Q. How is the amortization expense of the Colstrip Regulatory Asset impacted by the Company's proposal in this case?

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[39] The Colstrip related accounts included as rate base include the following: FERC Account No. 101.0 – Plant Cost, FERC Account No. 108.0 – Accumulated Depreciation, FERC Account No. 108027 – Colstrip Plant Adjustment, FERC Account No. 182.327 – Regulatory Asset Colstrip, FERC Account No. 230.027 – Colstrip ARO Liability, FERC Account No. 254.027 – Regulatory Liability Colstrip, FERC Account No. 242.0 – Colstrip Accounts Payable, and associated Accumulated Deferred Federal Income Taxes.

A. As shown in Table No. 5, removing transmission assets and adding the capital additions between January 1, 2020 and August 31, 2023, results in a revised annual regulatory amortization expense of $923,000 in RY1 and $977,000 in RY2 over the remaining 33 years.[40]

Table No. 5 – Idaho Colstrip Amortization Expense

Idaho Colstrip Amortization Expense ($000s)		
Amortization Expense Approved AVU-E-18-03	$	780
Additional Amortization Expense Approved AVU-E-19-04		83
Total Amortization Expense Approved AVU-E-19-04		863
Updates to Amortization Expense Filed in Case:		
Remove Transmission Assets from Deferral		(125)
Rate Year 1 - Capital Additions		185
Total Amortization Expense Proposed - Rate Year 1	$	923
Updates to Amortization Expense Filed in Case:		
Rate Year 2 - Capital Additions		54
Total Amortization Expense Proposed - Rate Year 2	$	977

The Final RY1 adjustment is Electric Adjustment (3.15) – **Pro Forma Wildfire Resiliency Plan Expense,** which reflects the increase in expenses related to the Company's Wildfire Resiliency Plan ("Wildfire Plan"), as supported by Mr. Howell.[41] This pro forma adjustment reflects the wildfire operating expenses expected during the rate effective

[40] See Pro Forma adjustment 22.07, which adjusts Pro Forma Colstrip Amortization Adjustment 3.14 amounts reflected in RY1, to include incremental RY2 capital additions and amortization expense planned in RY2 above RY1 levels.

[41] Wildfire Plan capital additions, together with associated A/D, ADFIT, and depreciation expense, from January 1, 2020 through August 31, 2023 over the Two-Year Rate Plan are included in Pro Forma Capital Additions Adjustments 3.08 through 3.10 in RY1, and Pro Forma Capital Additions Adjustments 22.01 and 22.02 in RY2, sponsored by Ms. Schultz. Mr. Howell discusses the need for these additions in his direct filed testimony.

period.[42] Section VI. "Wildfire Recovery and Balancing Account" below, provides additional information supporting the pro forma expenses and capital investment included in this case, as well as the proposed Wildfire Balancing Account to track expenses during the 10-year life of the plan. The effect of this adjustment decreases NOI by $1,654,000.

RY2 (09.2022 – 08.2023) – Summary of Adjustments

Q. Please now explain each of the RY2 Pro Forma adjustments included in Exhibit No. 5, starting on page 11 of Schedule 1 and page 10 of Schedule 2.

A. The Company has only included the incremental expenses above RY1 level expenses for the following major cost categories: 1) new plant investment, including depreciation (including updating Colstrip Unit 3 and 4 additions and regulatory amortization), through August 31, 2023 on an AMA basis and 2) property taxes on investment through 2021; as well as updates to certain O&M and A&G expenses, such as: 3) non-executive labor increases; 4) Wildfire Plan expenses; 5) Colstrip/CS2 maintenance expense; and 6) IS/IT expenses. The pro forma RY2 results do not reflect all incremental increases expected during RY2, and therefore, the results of the RY2 and incremental RY2 revenue requirement included in this filing for both electric and natural gas are conservative.

[42] As discussed by Mr. Howell, the Company has not included offsets to operating expenses in this case associated with wildfire. The goal of wildfire resiliency is to reduce the overall risk associated with wildfires. In short, the benefits of the Wildfire Plan are largely measured in terms of risk reduction for all parties involved. The Company, however, recognizes a potential for costs savings and cost shifts from operating and maintenance expense towards capital investment. The overall impact of cost savings and cost shifts will not be well understood until the Wildfire Plan is operational and performance data can be obtained and analyzed. However, one of the objectives of the Wildfire Plan is to reduce the number of equipment failures and tree-related outages and by doing so, avoid emergency response.

The Company has provided workpapers, both in hard copy and electronic formats, 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. 5, page 11 of Schedule 1 and page 10 of Schedule 2, is Electric Adjustment (22.01) and Natural Gas Adjustment (22.01) - **Pro Forma Capital Additions 08.2022 EOP**, which reflects September 1, 2021 through August 31, 2022 capital additions[43] together with the associated AD and ADFIT at an August 31, 2022 EOP basis. This adjustment also includes associated depreciation expense for these additions. In addition, the plant-in-service at August 31, 2022 AMA was adjusted to an August 31, 2022 EOP basis. Finally, 2022 retirements through August 31, 2022 on an EOP basis, on prior plant-in-service were included, reducing expense and the overall impact of this adjustment. Ms. Schultz describes this adjustment in detail within her testimony. The net impact of this adjustment is an increase in total rate base of $10,799,000 electric and $409,000 natural gas. The net effect of this adjustment on NOI is a decrease of $2,808,000 electric and $428,000 natural gas.

Electric Adjustment (22.02) and Natural Gas Adjustment (22.02) **Capital Additions 08.2023 AMA** reflects September 1, 2022 through August 31, 2023 capital additions[44] together with the associated AD and ADFIT at an August 31, 2023 AMA basis. This adjustment also includes associated depreciation expense for these additions. In addition,

[43] As noted previously, each of the periods 2020 through August 31, 2023, distribution-related capital expenditures associated with connecting new customers to the Company's system was excluded. An increase in revenues from growth in the number of customers from the historical test year to the RY1 and RY2 rate periods are excluded, therefore, the growth in plant investment associated with customer growth was also excluded.
[44] *Ibid.*

the plant-in-service at August 31, 2022 EOP was adjusted to an August 31, 2023 AMA basis. Finally, 2023 retirements through August 31, 2023 on an AMA basis, on prior plant-in-service were included, reducing expense and the overall impact of this adjustment. Ms. Schultz describes this adjustment in detail within her testimony. The net impact of this adjustment is an increase in total rate base of $24,835,000 for electric and $813,000 for natural gas. The net effect of this adjustment on NOI is an increase of $990,000 for electric and $173,000 for natural gas.

Q. Before continuing your discussion of RY2 Pro Forma Adjustments, is there specific information you would like to discuss regarding certain large and distinct capital investments?

A. Yes. As noted above, with the exception of the pro forma Colstrip Units 3 and 4 generation capital additions separately identified in Pro Forma Adjustments (3.14) for RY1 and (22.07) for RY2, Ms. Schultz sponsors the overall pro forma capital additions from January 1, 2020 through August 31, 2023 included in the Company's case in electric and natural gas Pro Forma Capital Additions adjustments (3.08) through (3.10) for RY1, and (22.01) and (22.02) for RY2. Included in those adjustments are large and distinct projects discussed by the following witnesses: 1) Mr. Howell discusses the Company's investment related to Avista's Wildfire Plan; 2) Mr. Kinney discusses the Company's investment related to Avista's investment in EIM; and 3) Mr. Magalsky discusses the Company's capital additions related to Avista's Customer Facing Technology investment. For ease of reference to the associated net plant investment and revenue requirement for these specific projects included in by Ms. Schultz in her adjustments, Table No. 6 below provides the individual net plant investment and revenue requirement for RY1 and RY2 for these three specific large and distinct projects.

<u>Table No. 6 – Wildfire, EIM & Customer Facing Technology Investment</u>

Idaho Net Plant Investment and Revenue Requirement (000s)								
	Wildfire Plan Investment		EIM Investment		Customer Facing Technology Investment			
	Electric		Electric		Electric		Natural Gas	
	RY1	RY2	RY1	RY2	RY1	RY2	RY1	RY2
Net Plant Investment	$ 9,190	$ 9,802	$ 5,584	$ 778	$ 5,352	$ 840	$ 1,424	$ 223
Two-Year Total Rate Base		$ 18,992		$ 6,362		$ 6,192		$ 1,647
Revenue Requirement	$ 1,122	$ 1,189	$ 1,280	$ 484	$ 2,077	$ 678	$ 552	$ 180
Two-Year Total Revenue Requirement		$ 2,311		$ 1,764		$ 2,756		$ 733

Q. Please continue with your explanation of the remaining RY2 pro forma adjustments included on page 11 of Schedule 1 and page 10 of Schedule 2 of Exhibit No. 5.

A. The next adjustments on page 11 of Schedule 1 and page 10 of Schedule 2 of Exhibit No. 5 include Electric Adjustment (22.03) and Natural Gas Adjustment (22.03) – **Pro Forma Property Tax**, which reflects incremental property tax expense from RY1 (included in Pro Forma Property Tax adjustment (3.05)) to RY2 using the most current information. As can be seen from my workpapers provided with the Company's filing, the property on which the tax is calculated is the property value as of December 31, 2021 at existing tax rates, reflecting the level of expense the Company will experience during 2022 and the RY2 rate period. The net effect of this adjustment decreases NOI by $589,000 electric and $100,000 natural gas.

Electric Adjustment (22.04) and Natural Gas Adjustment (22.04) – **Pro Forma Labor Non-Exec**, reflects incremental union and non-union wages and salaries from RY1 (included in Pro Forma Labor Non-Exec adjustment (3.01)) to RY2 (excludes executive salaries). For non-union and union employees, wages and salaries were adjusted to include an estimated increase of 3% for 2022 effective March 1, 2022 for non-union employees, and March 26, 2022 for union employees. The net effect of this adjustment on NOI is a decrease of $694,000 electric and $230,000 natural gas.

Electric Adjustment (22.05) and final RY2 Natural Gas Adjustment (22.05) – **Pro Forma IS/IT Costs**, adjusts the IS/IT expense level included in RY1 (included in Pro Forma IS/IT Costs adjustment (3.04)) to reflect incremental 2022 expected increases primarily associated with changes in contractual agreements, pre-paid costs, or the continuation of costs for products and services that will increase beyond the RY1 levels associated with products and services, licensing and maintenance fees, and other costs for a range of information services programs. These incremental expenditures are necessary to support Company cyber and general security, emergency operations readiness, electric and natural gas facilities and operations support, and customer service. Mr. Kensok sponsors this adjustment and provides more information within his testimony. The effect of this adjustment decreases NOI by $151,000 for electric and by $38,000 for natural gas.

Electric Adjustment (22.06) – **Colstrip/CS2 Maintenance,** adjusts the Colstrip/CS2 Maintenance expense level included in RY1 (see restating adjustment 2.12) to reflect the revised expense for RY2. This adjustment adjusts expense to one-third of each amount deferred for calendar years 2019 through 2021, increasing Idaho electric expense by approximately $379,000, and decreasing NOI by $286,000.

Electric Adjustment (22.07) **- Pro Forma Colstrip Capital and Amortization**, reflects the approved treatment (with one modification for transmission assets, described above in Adjustment 3.14) 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 Colstrip capital additions between September 1, 2022 and August 31, 2023 on an AMA basis in the Colstrip Regulatory Asset for recovery over its authorized amortization period.

The effect of this adjustment increases regulatory amortization expense by $53,000 and increases Colstrip net plant by $1,299,000. The net impact of this adjustment decreases electric NOI by $34,000.

The Final RY2 adjustment is Electric Adjustment (22.08) – **Pro Forma Wildfire Plan Expense,** which reflects the incremental increase in wildfire related expenses from RY1 (included in Pro Forma Wildfire Plan Expense adjustment (3.15)) to RY2, as supported by Mr. Howell.[45] Section VI. "Wildfire Recovery and Balancing Account" below, provides additional information supporting the incremental pro forma expenses included in this case, as well as the proposed Wildfire Balancing Account to track expenses during the 10-year life of the plan. The effect of this adjustment decreases NOI by $274,000.

<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 7.30% rate of return on a pro forma basis for the Two-Year Rate Plan?

[45] Wildfire Plan capital additions, together with associated A/D, ADFIT, and depreciation expense, from January 1, 2020 through August 31, 2023 over the Two-Year Rate Plan are included in Pro Forma Capital Additions Adjustments 3.08 through 3.10 in RY1, and Pro Forma Capital Additions Adjustments 22.01 and 22.02 in RY2, sponsored by Ms. Schultz. Mr. Howell discusses the need for these additions in his direct filed testimony. p

A. For electric, the net operating income deficiency amounts to $18,580,000 for RY1 and $6,540,000 (incremental) for RY2, as shown on line 5, page 3 of Exhibit No. 5, Schedule 1. The resulting revenue requirement is shown on line 7 and amounts to $24,783,000 for RY1, or an increase of 10.1%, and $8,722,000 (incremental) for RY2, or an increase of 3.2%.

Concurrent with the RY1 effective date (September 1, 2021), the Company proposes to return to customers the Tax ADIT benefit (if approved), beginning September 1, 2021 through separate electric Tariff Schedule 76 "Tax Customer Credit" of $24,783,000 million, offsetting the Company's requested electric base rate relief over approximately 15 months, resulting in no billed impact to electric customers. As discussed by Mr. Miller, electric Tariff Schedule 76 would be in effect September 1, 2021 until approximately November 30, 2022.

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 7.30% 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 $38,000 for RY1 and $712,000 (incremental) for RY2, as shown on line 5, page 3 of Exhibit No. 5, Schedule 2. The resulting revenue requirement is shown on line 7 and amounts to $52,000 for RY1, or an increase of 0.1%, and $950,000 (incremental) for RY2, or an increase of 2.2%.

Concurrent with the RY1 effective date (September 1, 2021), the Company proposes to return to customers the Tax ADIT benefit (if approved), beginning September 1, 2021 through separate natural gas Tariff Schedule 176 "Tax Customer Credit" of $1,226,000 million - reducing current natural gas billed rates by approximately 1.8%. As discussed by Mr. Miller, Tariff Schedule 176 would be in effect for the 10-year period September 1, 2021 through August 31, 2031.

In addition, concurrent with the RY2 natural gas effective date of September 1, 2022, the Company proposes to return to customers the Deferred Depreciation Expense balance of approximately $900,000,[46] through separate natural gas Tariff Schedule 177 "Deferred Depreciation Credit," resulting in an overall 0.1% bill impact to natural gas customers. As discussed by Mr. Miller, Tariff Schedule 177 would be in effect for the 12-month period September 1, 2021 through August 31, 2022.

VI. WILDIRE RECOVERY AND BALANCING ACCOUNT

Q. Please summarize the Company's Wildfire Resiliency Plan and its request of this Commission to recover planned wildfire costs.[47]

A. As noted above, Mr. Howell sponsors testimony detailing the Wildfire Resiliency Plan, annual costs and risks over the 10-year plan (2020 through 2029). Based on that Plan, included in Avista's Two-Year Rate Plan (and reflected in the Company's Electric Pro Forma Study RY1 and RY2 results) are Wildfire Plan capital additions for the period January 1, 2020 through August 31, 2023, and Wildfire Plan expenses for the RY1 and RY2 rate effective periods. Specifically, Wildfire Plan capital additions, together with associated A/D, ADFIT, and depreciation expense, are included in Pro Forma Capital

[46] See footnote 4.
[47] In addition to the requested rate relief included in this GRC, the Company recently received Commission approval in Case No. AVU-E-20-05, Order No. 34883,[47] of its Wildfire Plan Deferral Application, authorizing the Company to defer incremental wildfire O&M and depreciation expense prior to new rates going into effect (September 1, 2021), i.e., 2020 through August 31, 2021.

Additions Adjustments (3.08) through (3.10) in RY1, and Adjustments (22.01) and (22.02) in RY2, sponsored by Ms. Schultz. As shown in Table No. 6 above, Wildfire Plan capital additions included in the Company's case total $19.0 million over the Two-Year Rate Plan ($9.2 million in RY1 and $9.8 million in RY2).

Wildfire transmission and distribution operating expenses included in this case for RY1 and RY2 are discussed above and reflected in Wildfire Expense Adjustment (3.17) for RY1 and Adjustment (22.08) for RY2. Per Exhibit No. 5, Schedule 1, pages 10 and 11, Wildfire expenses included in the Company's case total $2.6 million ($2.2 million in RY1 and $0.4 million in RY2).[48]

The Company is also requesting the Commission authorize the Company to create a two-way Wildfire Balancing Account, based off the base level of wildfire expense included in each GRC going forward, tracking the actual annual difference up or down over the 10-Year Wildfire Plan. Each of these recovery proposals are discussed further below.

In summary, although the Company will still experience regulatory lag on capital additions between rate cases over the 10-Year Wildfire Plan, approval of the Company's proposals, mainly impacting wildfire expenses and rate period capital additions as outlined in this testimony, is an important element of the Company's wildfire program and helps support the level of wildfire mitigation efforts proposed in the Company's Wildfire Plan.

Q. While you will provide more granularity of what Avista has included in this case, what is the total overall electric revenue requirement included in this case related to the Company's Wildfire Resiliency Plan?

[48]As noted below, the resulting net revenue requirement of the total Wildfire Plan capital additions and expense is $4.9 million ($3.3 million in RY1 and $1.6 million in RY2). Further detail of the included amounts is discussed below.

A. The overall electric revenue requirement included in this case associated with Wildfire Plan total capital additions and expense is approximately is $4.9 million over the Two-Year Rate Plan ($3.3 million in RY1 and $1.6 million in RY2).

Q. Please provide a brief summary of the Company's Wildfire Resiliency Plan.

A. As discussed by Mr. Howell, the risk of large wildfire events is increasing across the western United States. Recent fire events in Avista's own service territories of Idaho, Washington and Oregon, as well as major wildfire activities in other states such as California, illustrate that utility operating risk is increasing related to wildfires. Reducing the risk of wildfires is critical for customers, communities, investors, and the regional economy. Avista has taken a proactive approach for many years to manage wildfire risks and impacts, and through its Wildfire Plan, the Company has identified additional wildfire defenses for implementation. The goals, strategies, and tactics set forth in this plan reflect a quantitative view of risk. Additional research, conversation and analysis with Avista's operating staff and steering group provided critical qualitative and contextual information that also shaped the recommendations. This combination of quantitative and qualitative analysis ensures the recommendations are robust, well-rounded, and thoughtful, and that they align with the plan goals and are appropriate. Mr. Howell's direct testimony provides details behind the creation of the Wildfire Plan. Exhibit No. 12, Schedule 1 is a copy of the Wildfire Plan.

As presented in Table No. 7 below, the Company's Wildfire Plan, including all 28 plan recommendations discussed by Mr. Howell, expects total costs over the ten-year period 2020 through 2029 to reflect capital investment of $268,965,000, and corollary operating expenses of $59,586,000 (electric system numbers). Annual program costs for the period

2020 – 2029 are also shown in Table No. 7 as follows:

<u>Table No. 7 – Wildfire Annual System Capital Investment & Operating Expense</u>

(000s)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	10-YR Ttl
Capital	$5,265	$16,985	$27,055	$31,380	$31,380	$31,380	$31,380	$31,380	$31,380	$31,380	$268,965
O&M	$2,416	$5,371	$6,917	$7,435	$7,354	$6,772	$6,540	$6,059	$5,627	$5,096	$59,586

These total capital investments and expenses of the Wildfire Plan will be directly assigned, where possible, or allocated to Avista's Idaho and Washington jurisdictions over time as the costs occur. (Shaded areas in Table No. 7 above reflect system balances considered in this case.)

Q. What Wildfire Plan costs have been included in this general rate case?

A. Specific costs proposed by Avista in this general rate case reflect the expected wildfire related transmission and distribution costs to be charged to Idaho during the RY1 and RY2 rate effective periods, i.e. September 1, 2021 through August 31, 2023. Table Nos. 8 and 9 below split the annual system and Idaho expected capital and operating expenses between distribution and transmission for the calendar periods 2020 through 2023 only, for the 10-year plan. Using this information, the Company has incorporated the incremental wildfire costs within Electric Pro Forma Study Exhibit No. 5, Schedule 1.

<u>Table No. 8 – Wildfire Plan Capital Investment – Idaho-Share & System (000s)</u>

Total Wildfire Plan - Idaho and System (Capital)						
	Idaho			System		
	Distribution	Transmission	Total	Distribution	Transmission	Total
2020	**1,298**	**691**	**1,988**	**3,255**	**2,010**	**5,265**
2021	**5,099**	**1,361**	**6,459**	**13,025**	**3,960**	**16,985**
2022	**8,252**	**2,022**	**10,274**	**21,170**	**5,885**	**27,055**
2023	**10,022**	**1,996**	**12,018**	**25,570**	**5,810**	**31,380**

Included in Pro Forma Capital Additions Adjustments (3.08) through (3.10) in <u>RY1</u>

are Idaho distribution and transmission wildfire gross plant additions, transferring to plant during the period 2020 through August 31, 2022, totaling $10.1 million. Additionally, included in Pro Forma Capital Additions Adjustments (22.01) and (22.02) in RY2 are Idaho distribution and transmission wildfire gross plant additions, transferring to plant September 1, 2022 through August 31, 2023, totaling $11.0 million.[49] The revenue requirement included in the Company's filed case, related to these wildfire capital additions, including depreciation expense and the tax effect of debt interest, total approximately $1.1 million and $1.2 million in RY1 and RY2, respectively.

Table No. 9 – Wildfire Plan O&M Expense – Idaho-Share & System (000s)

Total Wildfire Plan - Idaho and System (Expense)						
	Idaho			System		
	Distribution	Transmission	Total	Distribution	Transmission	Total
2020	606	302	909	1,536	880	2,416
2021	1,610	455	2,065	4,047	1,325	5,372
2022	2,117	550	2,667	5,316	1,602	6,918
2023	2,323	550	2,874	5,834	1,602	7,436

Wildfire distribution and transmission operating expenses as shown in Table No. 9 above, were included in the Company's filing in Pro Forma Wildfire Expenses Adjustment (3.15) for RY1, and Pro Forma Wildfire Expenses Adjustment (22.08) for RY2. The prorated amount of calendar 2021 ($2.065 million) and 2022 ($2.667 million) included in RY1 totaled approximately $2.195 million (Idaho-share) for operating expenses (and $2.207 million revenue requirement).[50] Additionally, the prorated amount of calendar 2022 ($2.667

[49]In both RY1 and RY2, these plant additions, are included on an AMA basis for the rate effective period ($10.1 million and $11.00 million, respectively), net of A/D and ADFIT, results in a net rate base adjusted amount of $9.2 million in RY1, and $9.8 million in RY2 as shown in Table No. 6 above.

[50]Wildfire risk tree and other expenditures are incremental to existing vegetation management expenses included in the 2019 test period, with the exception of approximately $265,000 (Idaho/Washington). For RY1 the calculation of the operating expense included in this case was calculated based on Idaho's share of prorated 2021 and 2022 expenses, offset by existing vegetation management expense included in the 2019 test period of $81,000 (Idaho-share). See Andrews workpapers for analysis.

million) and 2023 ($2.874 million) totaled approximately $2.56 million, for an incremental amount included in RY2 of approximately $363,000 (Idaho-share) for operating expenses (and $365,000 revenue requirement).

Q. What is the total overall electric revenue requirement included in this case?

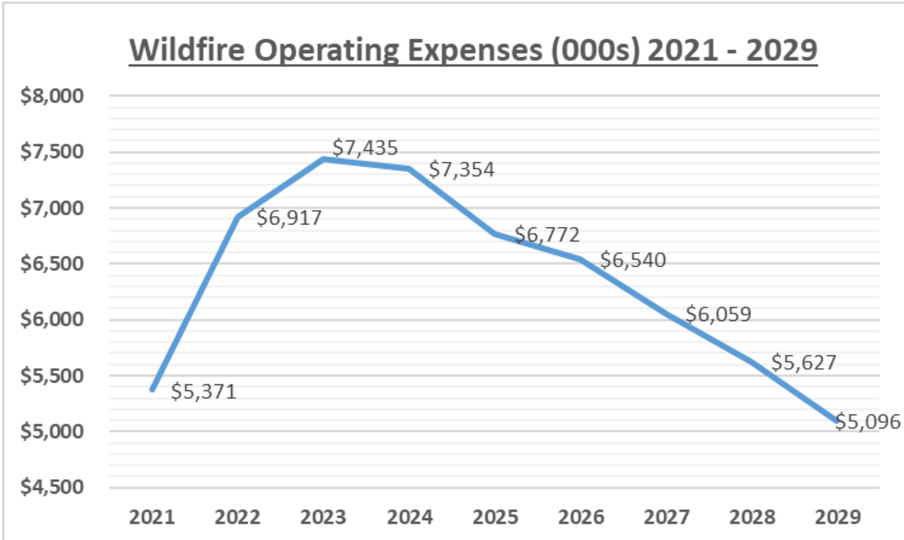
A. As stated earlier, the overall electric revenue requirement included in this case associated with Wildfire Plan total capital additions and expense is approximately is $4.9 million over the Two-Year Rate Plan ($3.3 million in RY1 and $1.6 million in RY2).

Q. Please turn now to the Company's proposal to create a Wildfire Balancing Account related to wildfire expenses.

A. Lastly, the Company is proposing to create a Wildfire Balancing Account to track the variability in wildfire expenses over the 10-year life of the Wildfire Plan. As shown in Illustration No. 1 below, the O&M expenses on a system annual basis over the 10-year life of the Wildfire Plan increases from $5.4 million in 2021[51] to a maximum increase of $7.4 million in 2024, before declining over the remaining years to $5.1 million in 2029, producing more of a "bell-shaped" curve.

[51] The first partial year of the Wildfire Plan in 2020 of $2.4 million system is not shown.

Illustration No. 1 – Wildfire System Annual Operating Expenses



Given this expected “bell-shaped” curve of expenses beginning after the first partial year (2020), and that expenses are expected to begin to decline after year 4 (2024) of the Wildfire Plan, in order to protect customers by ensuring customers pay no-more/no-less of the O&M expenses of this Wildfire Plan, the Company believes it prudent for the Commission to establish a two-way balancing account for these costs. By establishing a base level of expense in this case of $2.195 million in RY1 and $2.558 million in RY2 (included in Pro Forma Wildfire Expense Adjustment (3.15) for RY1 and (22.08) for RY2 in Exhibit No. 5, Schedule 1) and each subsequent general rate case following, allowing the Company to track actual expenses against the base, and defer the difference up or down over time for later recovery or return to customers, will ensure customers pay no more than the actual wildfire expenditures over the 10-year plan.

Avista proposes to record the deferral balances (expense levels higher or lower than the GRC established base) into a balancing account recorded as a separate regulatory asset in FERC Account 182.3 (Other Regulatory Assets), and credit FERC Account 407.4

(Regulatory Credit). The costs as incurred will be debited to various expense accounts. In each subsequent general rate case proceeding, Avista would propose a new base, made up of the expected rate effective period expenses. The level of expense included in that GRC however, will be offset by or added to the deferred amount in the wildfire balancing account. The Company would address in each GRC the prudence of any deferred balances. The intent of the balancing account is to track actual costs and match dollar-for-dollar what is collected from customers during the period September 1, 2021 through December 31, 2029. The Company proposes that interest will not accrue on the unamortized balance.[52]

Q. Please discuss the Wildfire Deferral Application recently approved by the Commission.

A. The Idaho Commission recently approved Avista's Wildfire Plan Deferral Application (Case No. AVU-E-20-05, per Order No. 34883), authorizing the Company to defer incremental wildfire O&M and depreciation <u>expense</u> prior to new rates going into effect (September 1, 2021), i.e., 2020 through August 31, 2021. Support of the Wildfire Plan itself, and costs and risks over the 10-year Wildfire Plan were provided in detail in the Wildfire Deferral Application, as well as discussed in Attachments A through E of the Wildfire Deferral Application.[53]

Approval of Avista's Wildfire Deferral Application, authorized Avista to defer its actual incremental wildfire O&M and depreciation expenses in 2020 (approximately $1.1

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[52] Tracking the on-going expenses versus an approved base over the life of the 10-year plan would allow the Company to set these costs aside for an opportunity to recover these costs in future rate proceedings and ensure customers pay no more/no less than actual wildfire expenses incurred. Any costs deferred and set aside for a future period will provide this Commission and other parties the opportunity to review the costs after-the-fact and make a prudence determination prior to the Company receiving recovery of the prudently incurred costs.

[53] Attachments A through E of the Wildfire Deferral Application have been provided in this proceeding, sponsored by Mr. Howell, Exhibit No. 12, Schedules 1 through 6.

million Idaho-Share) and actual 2021 expenses prior to new rates going into effect (estimated at $1.5 million through August 31, 2021) of Avista's actual Wildfire Plan efforts. The expected amount to be deferred during the fifteen-month period June 1, 2020 through August 31, 2021, is therefore estimated at $2.6 million. Avista will record the monthly deferral as a regulatory asset in FERC Account 182.3 (Other Regulatory Assets) without a carrying cost, and credit FERC Account 407.4 (Regulatory Credit). The costs as incurred will be debited to various expense accounts.

Avista will address the prudence of the costs incurred and request recovery of the deferred costs, including a carrying charge on the deferral at the authorized rate of return, in a future general rate case proceeding. At that time, the Company will also propose an amortization period to recover the costs from Idaho customers over a future period.

VII. TAX ACCOUNTING APPLICATION – BASIS ADJUSTMENTS IDD #5 AND METERS

Q. Please summarize the Company's accounting application filed with the Commission on October 30, 2020, requesting approval to change its accounting for federal income taxes.

A. As discussed by Mr. Krasselt, and summarized below, the Company filed with this Commission on October 30, 2020 its "Application for an Order Authorizing Approval to Change Its Accounting for Federal Income Tax Expense Certain Plant Basis Adjustments and Deferral of Associated Changes in Tax Expense" (Tax Accounting Application). Mr. Krasselt in his supporting testimony describes in more detail the Company's Tax Accounting Application and explains the Company's request seeks authorization to change its accounting for federal income tax expense from the normalization method to a flow-through method for certain "non-protected" plant basis adjustments,[54] including Industry Director Directive No. 5 (IDD #5) and meters.[55] Approval of the Company's Tax Accounting Application would provide benefits to customers, which the Company also through the Tax Accounting Application, is requesting approval to defer. However, <u>approval in all three of Avista's jurisdictions</u> (Idaho, Washington and Oregon) to make this change is required, and any changes need to be adjusted concurrent with a GRC, as it has significant impact on tax expense and rate base. Furthermore, the Company has requested in its Tax Accounting Application approval of the change in accounting, and the deferral of benefits, on or before May 1, 2021, to ensure approval from all three jurisdictions is received in time to apply this change and return the customer benefits in each state effective with each State's next general rate case.

As discussed further below, after receiving approval in all three jurisdictions of the accounting change and the deferral of the benefits, the Company is proposing to begin

[54] As noted by Mr. Krasselt, during 2020, Avista worked with consultants from the Deloitte accounting firm on a 2019 tax review project. The outcome of this project was to expand on the tax deduction for repairs expenses that the Company originally implemented in 2014. This change allowed the Company to deduct costs for tax purposes that previously were capitalized, thereby reducing current federal income taxes owed to the IRS. While the Company expanded its deduction for repairs expenses, the deferred taxes for this deduction will continue to be normalized and therefore, are not part of the deferral application or the credits available for the Tax Customer Credits.

[55] In addition to the repairs review, Avista filed two new accounting method changes with the IRS to modify its tax method for accounting for certain costs relating to IDD #5 and meters. IDD #5 relates to mixed services costs that are part of the capitalized book costs of utility property but can be capitalized to inventory and expensed for tax purposes as a cost of goods sold expenditure. The meter accounting method change allows Avista, for income tax purposes, to deduct meter costs instead of capitalizing them if the per unit cost is less than $200. These changes were included with the 2019 federal tax return that was filed in October 2020 and is the basis of the request for an accounting change in the Company's Tax Application.

amortization of the deferred benefits, concurrent with the effective date of this GRC.[56]

Q. What is the basis of the Company's change in accounting requested?

A. There are two methods that regulated utilities may use to record the federal income taxes related to book-to-tax differences, (1) normalization and (2) flow-through. Using a normalization method to compute income tax expense simply means that all the income tax costs related to items in the current period will be computed, whether paid in the current year or paid later. This method creates deferred income tax and the associated accumulated deferred income tax that is subtracted from rate base.

Flow-through accounting generally treats the actual current Federal income tax liability of the regulated utility as the utility's tax expense in determining utility rates. Thus, under flow-through accounting, the tax benefits of accelerated tax expense and other similar items are taken into account immediately in determining utility rates (through their effect of reducing current income tax expense). Accumulated deferred tax reserves related to tax items that have been flowed through are not included in the rate base calculation as the tax benefit was provided, or flowed-through, to customers.

Currently the Company uses the normalization method for accounting for most of its federal income taxes related to book-to-tax differences – both "protected" and "non-

[56] As discussed by Mr. Krasselt, in the Northwest we are aware that Idaho Power and Northwest Natural utilize the flow-through method of accounting for some of their non-protected book-to-tax differences. It is our understanding that the following state utility commissions have authorized flow-through accounting for certain of its regulated utilities: California, Idaho, Iowa, Louisiana, Montana, South Dakota, Maine, Wisconsin, Pennsylvania and New Jersey, although this is not an exhaustive list. Specific utility examples include, Pacific Gas and Electric Company in California, Pennsylvania Power and Light Electric Utilities Corporation, NorthWestern Energy in Montana, South Dakota and Nebraska, Cleco Power LLC in Louisiana, and Wisconsin Electric Power Company, to name a few.

protected."[57] Through the Company's Tax Accounting Application, the Company is proposing to change to the flow-through method of accounting for income taxes for certain "non-protected" plant basis adjustments (related to IDD#5 and meters) that the Company developed with the 2019 tax review project it completed in 2020. Approval of this accounting change would create tax benefits that could be returned to customers.

Q. What is the breakdown of the protected and non-protected deferred tax balances, after adjustment for the tax review?

A. Avista records the accumulation of deferred taxes on plant book-to-tax differences in FERC Account No. 282900. As of December 31, 2019, FERC Account No. 282900 contained a balance of $819 million that has been normalized prior to adjustments related to the tax review. After adjustment for the tax review, the estimated balance is $885 million. Much of this balance is protected because it relates to accelerated depreciation, including bonus depreciation[58]. However, included in FERC Account No. 282900 is non-protected basis adjustments (i.e. IDD #5, meters, repairs and other). Avista has historically normalized the entire FERC Account No. 282900 balance.

Table No. 10 below shows the breakdown of the protected and non-protected deferred tax balances, after adjustment for the tax review, as of December 31, 2019:

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[57] The IRS requires normalization on book-to-tax differences it considers protected. The capitalizing of utility property under IRC§ 263(a) constitutes protected assets that are subject to the normalization requirement under IRC § 168(i)(9). The two primary areas that give rise to protected differences are book-to-tax differences for depreciation method and depreciable life of the asset (commonly referred to as "method/life differences"). The normalization requirements of the Internal Revenue Code are designed to prohibit the direct or indirect flow-through of accelerated depreciation tax benefits to utility customers. Other book-to-tax differences not related to method/life differences are considered non-protected, such as expenditures capitalized for book purposes but allowed as a deduction for tax purposes. These non-protected book-to-tax differences are not required to be normalized.

[58] Bonus depreciation is a tax incentive that allows a business to immediately deduct a large percentage of the purchase price of eligible assets, such as machinery, rather than write them off over the "useful life" of that asset.

Table No. 10: Protected/Non-Protected Deferred Tax Balances at December 31, 2019

FERC Account No. 282900 - ADFIT Estimated Balance at December 31, 2019	
Protected	$ 599,773,098
Non-Protected - Proposed Flow-Through	106,824,795
Non-Protected - Other	178,574,508
	$ 885,172,401

By changing to the flow-through method of accounting for certain basis adjustments, including IDD #5 and meters, as discussed by Mr. Krasselt, Avista will have an estimated $106.2 million (system) of ADIT as of December 31, 2019, which represents approximately $134.4 million (system grossed-up for federal income taxes) that can be recorded in a regulatory liability and used to offset customers' rates in future general rate cases. Detail of these balances have been provided by Mr. Krasselt as Exhibit No. 4, Schedule 1. A summary of the estimated ADIT amount by jurisdiction is shown in Table No. 11 below.

Table No. 11: Tax Benefit by Jurisdiction through December 31, 2019

Tax Impact of Basis Adjustments (IDD #5 and Meters)
December 31, 2019

	ADFIT	**Grossed-up for Federal Taxes**
WA Electric	$ (40,748,313)	$ (51,580,143)
ID Electric	(21,941,399)	(27,773,923)
WA Natural Gas	(19,653,292)	(24,877,585)
ID Natural Gas	(8,422,839)	(10,661,822)
OR Natural Gas	(15,443,480)	(19,548,709)
	$ (106,209,323)	$ (134,442,181)

Avista would have an annual additional tax benefit each year, beginning in 2020, which would be available for immediate use to offset customers' rates, estimated to be $16.4 million, shown in Table No. 12 below.

Table No. 12: Tax Benefit by Jurisdiction for Calendar 2020

Estimated Tax Impact of Basis Adjustments (IDD #5 and Meters) Annual Additional Amounts		
	ADFIT	**Grossed-up for Federal Taxes**
WA Electric	$ (5,179,775)	$ (6,556,678)
ID Electric	(2,789,110)	(3,530,519)
WA Natural Gas	(2,624,993)	(3,322,776)
ID Natural Gas	(1,124,997)	(1,424,047)
OR Natural Gas	(1,240,032)	(1,569,661)
	$ (12,958,907)	$ (16,403,679)

The total of the tax benefits included in Table Nos. 11 and 12, therefore, through December 31, 2020, associated with changing to the flow-through method of accounting for IDD#5 and meters, and available for use to offset customers' rates, after receiving approval in all three jurisdictions, is estimated at $150.8 million (system), or $31.3 million for Idaho electric, and $12.1 million for natural gas.

Q. Why is it important to make the requested modifications concurrent with a general rate case as proposed by the Company?

A. ADFIT is a reduction to rate base. If Avista was authorized to change to the flow-through method of accounting for the proposed basis adjustments IDD #5 and meters, and the tax benefits were to be given to customers over a shorter period than if using the normalization method, the ADFIT balance related to these basis adjustments would not be included in the rate base calculation, as the amount would have already been flowed through to customers. Given this complexity, it is through a general rate case that the proposed modifications need take place, with the benefit used to mitigate such rate filings and appropriately track changes in rate base and other accounts.

Q. How has the Company proposed to account for the change in accounting as requested in the Tax Accounting Application?

A. The Company has provided detailed calculations and accounting entries that reflects the impact of changing from using the normalization method for the new basis adjustments to the flow-through method filed with the Tax Accounting Application. A high-level summary of those accounting entries follows.

Avista will record the 2019 tax return adjustments and all future monthly tax accruals using the normalization method, until the Company receives approval to change to the flow-through method in all three states. This allows the Company to continue to record deferred taxes and will increase the ADIT balance recorded in FERC Account No. 282900.

After the Company receives approval from all three states to utilize the flow-through method of accounting for IDD #5 and meters, as described above, the Company will record the amounts that have accumulated at that point related to those basis adjustments to FERC Account No. 254.3 – Regulatory Liability at the grossed-up amount. Associated deferred taxes will be recorded on this deferral in FERC Account No. 190 – ADFIT. The net of these two accounts will equal the amount that had been recorded in FERC Account. No. 282900 and will be included as an offset to rate base until flow-through begins. This will allow customers to continue to receive the benefits of the basis adjustments, as a reduction to rate base, until such time the flow-through benefits are included in rates.

Q. What is the Company proposing with regards to the amortization of the

tax benefits?

A. As a part of this general rate case, if the Tax Accounting Application's proposed accounting treatment is approved by all three jurisdictions (Idaho, Washington and Oregon), as well as approval to defer these tax benefits, the Company proposes to return the accumulated tax benefits that will be recorded in FERC Account No. 254.3 over a shorter period of time than the current normalization method allows, taking into consideration the impact of any proposed change in base rates. Once those credits are being returned to customers, the Company will amortize the accumulated tax benefits recorded in the regulatory liability account as proposed in this filing. The Company is also proposing to defer the future annual benefits of the IDD# 5 and meters basis adjustments to ensure the customer receives all benefits from the flow-through in future general rate cases.

As discussed by Company witness Mr. Miller, concurrent with the effective date of this general rate case, the Company proposes to return to customers the tax benefit, beginning September 1, 2021, for approximately one and one quarter (1¼) years for electric and ten (10) years for natural gas, through separate Tariff Schedules 76 (electric) and 176 (natural gas), titled "Tax Customer Credit," of $24.783 million for electric and $1.226 million for natural gas - offsetting the Company's requested electric base rate relief - resulting in no billed impact to electric customers; and reducing current natural gas billed rates by approximately 1.8%. Therefore, the amortization and the Tax Customer Credit Tariff Schedules 76 and 176, if approved as filed, would be in place from September 1, 2021 through November 30, 2022 for electric and August 31, 2031 for natural gas.

Furthermore, as discussed by Mr. Thies, because the return of the Tax Customer Credit benefits will have an impact on the Company's cash flow, weakening credit metrics tracked by the rating agencies, the Company requests that, regardless of the electric and natural gas base revenue increases approved in this case, the electric and natural gas tax benefit amortization does not go beyond base rate increases approved on an annual basis, and does not go beyond a two year amortization period for those increases.[59] Any remaining balance after the two-year amortization of the rate period increases included in Tariff Schedule 76, for example, plus the on-going, incremental, annual deferred tax benefit recorded starting in January 2021 for both electric and natural gas, would be amortized over a 10-year period going forward in a future period. With regards to natural gas, with RY1 resulting in a de minimis rate change of $54,000, the Company has proposed the Customer Tax Credit through Tariff 176 be amortized over a 10-year period effective September 1, 2021.

We believe this proposal properly balances the rate impact to customers and the Company's financial health. In addition, a 10-year amortization is significantly shorter, benefiting customers longer-term than if the IDD#5 and meters basis adjustments remained using normalization accounting, which would amortize these balances over approximately 34+ years for IDD#5 and approximately 15 years for meters.

[59] As discussed by Mr. Thies, currently the Company's credit rating is at BBB, two notches above "non-investment grade" rating levels. A downgrade to our ratings to one-notch above or to non-investment grade, could be possible if the Commission were to include a higher amortization balance than the approved rate increases. That is true as well if the Commission went beyond the two-year amortization period proposed in this filing.

VIII. 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-19-04 and AVU-G-17-01, 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.