Exh. EMA-1T

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET NO. UE-19________

DOCKET NO. UG-19________

DIRECT TESTIMONY OF

ELIZABETH M. ANDREWS

REPRESENTING AVISTA CORPORATION

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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 State and Federal Regulation 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 as a Regulatory Analyst until my promotion to Manager of Revenue Requirements in early 2007, and later promoted 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 generally cover accounting and financial data in support of the Company's need for the proposed electric and natural gas rate relief requested in the Company's filing. I will first summarize the Company's revenue increase requests for the proposed Two-Year Rate Plan for the period April 1, 2020 through March 31, 2022.[2] Avista has proposed electric and natural gas revenue increases to become effective April 1, 2020 and April 1, 2021. The filing of one rate case for a two-year period will reduce the burden to all stakeholders of processing a general rate case every year.

For Rate Year 1, effective April 1, 2020, I will explain pro formed operating results, including expense and rate base adjustments made to actual operating results and rate base. Included with the restating and pro formed adjustments, are certain adjustments sponsored by other witnesses, which I incorporate the Washington-share of those proposed adjustments in this case. Results for Rate Year 1 reflect an electric and natural gas revenue requirement request of approximately $45.8 million and $12.9 million, respectively.

For Rate Year 2, I will explain the Company's proposed Revenue Growth Rate percentage to be applied to Year 1 proposed revenues, resulting in the revenue increase for Year 2, to be effective April 1 of 2021. Results for Rate Year 2 reflect an electric and

[2] The Two-Year Rate Plan would not preclude tariff filings authorized by or contemplated by the terms of the Energy Recovery Mechanism (ERM), Purchased Gas Adjustment (PGA), Public Purpose Rider Adjustment (DSM/LIRAP) or similar 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 new safety or reliability requirements imposed by regulatory agencies, or the recovery of unanticipated expenses beyond the Company's control – e.g., fire, wind and snowstorms.

natural gas revenue requirement request of approximately $18.9 million and $6.5 million, respectively.

In addition to discussing the Company's needed rate relief, I will also discuss the Company's proposed treatment for recovering, on an accelerated basis, the depreciation expense associated with its 15% ownership of Colstrip Units 3 and 4 that was originally included as a settlement proffered to the Commission in Docket Nos. UE-180167 and UG-180168, but was set over for a later determination in this rate case.[3]

Lastly, I will discuss changes in FASB and FERC accounting methods since Avista's last general rate case filing in Washington. Only the FERC change associated with AFUDC impacted the Company's operating results beginning in 2018, as explained in the Company's filing with the WUTC on January 31, 2019 (Docket No. UE-190074/UG-190075).

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

A. Yes. I am sponsoring Exh. EMA-2 through EMA-6, which were prepared by me. Exh. EMA-2 (Electric) and Exh. EMA-3 (natural gas) present the results of the Company's electric and natural gas Pro Forma Studies, which show actual 2018 operating results (twelve-month period ending December 31, 2018), pro forma, and proposed electric and natural gas operating results and rate base for the State of Washington. The exhibits also show the calculation of the general revenue requirement, the derivation of the

[3] The revenue requirement in this case was completed prior to the finalization of the "100% Clean" legislation, which is expected to be signed into law in early May 2019, requiring the removal of coal in Washington State by 2025. The Company will update its proposed impact of using an accelerated depreciation date of 2025 for its Colstrip assets in Washington after consulting with its Depreciation Consultant, Gannett Fleming, for revised depreciation rates, and our determination of the revised impact to the proposed revenue requirement. Based on preliminary estimates, the Company anticipates the increased Colstrip Regulatory Asset and amortization to reflect a 2025 depreciable life would require an increase in revenue requirement of approximately $236,000, above moving to a 2027 depreciable life as included in this case.

Company's overall proposed rate of return, the derivation of the net-operating-income-to-gross-revenue-conversion factor, and the specific restating and pro forma adjustments proposed in this filing. Exh. EMA-4 (electric) and Exh. EMA-5 (natural gas), present the electric and natural gas proposed Revenue Growth Rate percentage and calculation to be applied to Year 1 proposed revenues (excluding energy and natural gas cost-related revenues), resulting in the revenue increase for Year 2, as shown on Exh. EMA-2 and EMA-3, page 2. Exh. EMA-6 provides the service and jurisdiction allocation methodologies used by the Company. Finally, Exh. EMA-7 provides electronic files of all restating and pro forma adjustments. (Additional detailed calculations of the service and jurisdiction allocation methodologies used by the Company, along with a hard copy of all restating and pro forma adjustments, are provided within my workpapers filed with this case.)

II. SUMMARY OF PROPOSED ELECTRIC AND NATURAL GAS TWO-YEAR RATE PLAN

Q. Please summarize the Company's electric and natural gas Two-Year Rate Plans proposed for April 1, 2020 through March 31, 2022?

A. The Company is proposing a Two-Year Rate Plan (Rate Plan) including the period April 1, 2020 through March 31, 2022, with proposed revenue increases effective April 1, 2020 and April 1, 2021.

With an April 1 effective date, this filing continues to have the effect of changing the "cycle" of base rate adjustments from the middle of winter to April 1st – after the end of the winter heating season. Therefore, the timing of this filing, together with the Rate Plan, will avoid base rate adjustments for customers in the middle of winter for the next two years.

Furthermore, the Two-Year Rate Plan will provide a degree of rate predictability for customers, and a respite from the burdens and costs of the current pattern of continuous annual rate case filings for the Company, Staff, and other participants. The Two-Year Rate Plan will also provide an incentive for Avista to manage its costs in order to earn the authorized rate of return proposed in this filing over the Rate Plan period.[4]

Q. Please provide a brief overview of the calculation of Rate Year 1 versus Rate Year 2 revenue requirements used by Avista to demonstrate the need for rate relief in this case.

A. Rate Year 1, with a proposed effective date of April 1, 2020, was prepared as a traditional pro forma study, including restating and pro forma adjustments beyond the historical test year (2018). Included with the electric and natural gas restating adjustments is an End-Of-Period (EOP) 2018 Net Plant adjustment, adjusting net plant from an average-of-monthly-average (AMA) 2018 historical test year balance to a 2018 EOP net plant historical test-year balance, similar to that approved by the WUTC in Avista's last general rate case proceeding (Docket Nos. UE-170485 and UG-170486). As discussed later in my testimony, without this EOP 2018 Net Plant adjustment to reduce regulatory lag experienced by the Company, the Company would have no chance of earning its authorized rate of return proposed in this case in Rate Year 1, which would be further exacerbated in Rate Year 2. The results of the electric and natural gas Pro Forma Studies for Rate Year 1 is $45.8 million for electric and $12.9 million for natural gas.

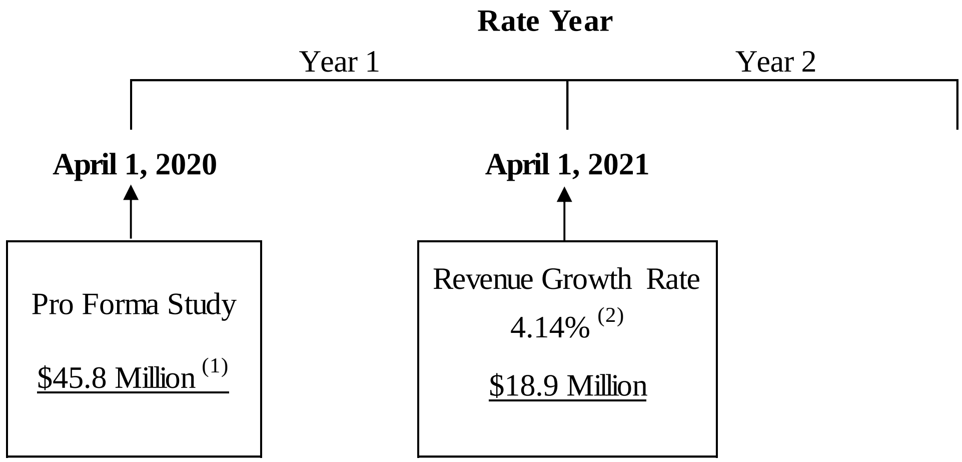
[4] Company witness Mr. Vermillion also discusses the decision to propose a Two-Year, rather than a Three-Year Rate Plan, in light of varying circumstances, such as timing of completion of the Company's Advanced Metering Infrastructure (AMI) project in 2021, changes on the horizon related to some legislative initiatives, as well as an opportunity to allow for staggered peer utility rate-plans.

The Rate Year 2 revenue increases, with a proposed effective date of April 1, 2021, were based on the Company's proposed Revenue Growth Rate percentage. The Revenue Growth Rates for both electric and natural gas, were developed based on the historical trend of changes in rate base components and operating expenses, using normalized data from prior Commission Basis Reports for the period 2014 through 2018, offset by annual expected revenues from 2018 through the end of Rate Year 1 (March 31, 2021). For Rate Year 2, the annual Revenue Growth Rate is applied to the energy (non-ERM) and non-gas cost authorized revenues at the time Year 2 rate changes go into effect. The results of applying the proposed annual electric and natural gas Revenue Growth Rate to Rate Year 1 proposed revenues, results in Rate Year 2 electric and natural gas increases of $18.9 million and $6.5 million, respectively.

Q. By way of summary, would you please illustrate how the proposed revenue increases for each of the rate years were developed?

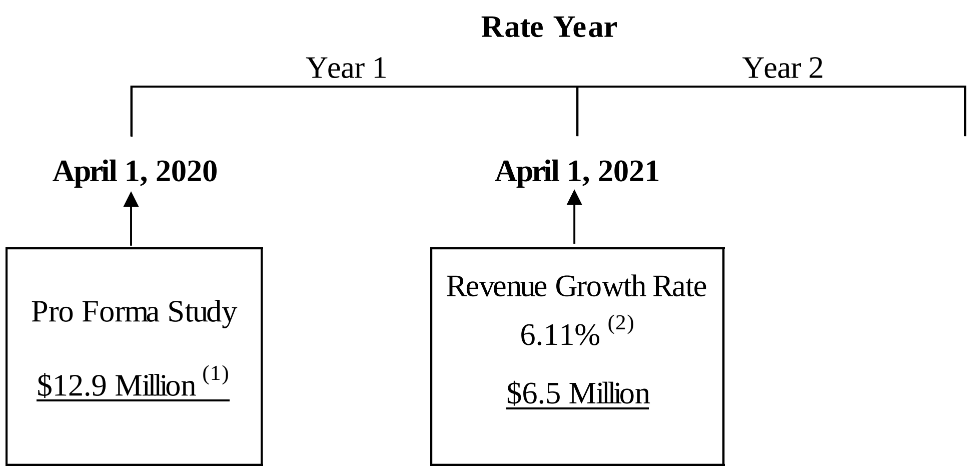
A. Yes. Illustration Nos. 1 (electric) and 2 (natural gas) below show how the revenue increases for Rate Year 1, effective April 1, 2020, were based on the electric and natural gas Pro Forma Studies, while Year 2 of the Rate Plan were determined from applying the Revenue Growth Rate to Year 1 revenues.

<u>Illustration No. 1: Derivation of Electric Revenue Requirement - Two-Year Rate Plan</u>



(1) See Exh. EMA-2, p. 2, ln. 7
(2) See Exh. EMA-4, p. 1 for Revenu Growth Rate; EMA-2, p. 2, ln. 14 (for Revenue Rqmt.)
The 4.14% Revenue Growth Rate is based on non-energy amounts. On a <u>billed</u> basis (including total revenues) this percentages reflects a 3.35% proposed increase.

<u>Illustration No. 2: Derivation of Natural Gas Revenue Requirement - Two-Year Rate Plan</u>



(1) See Exh. EMA-3, p. 2, ln. 7
(2) See Exh. EMA-5, p. 1 (for Revenue Growth Rate); EMA-3, p. 2, ln. 14 (for Revenue
The 6.11% Revenue Growth rate is based on non-gas cost amounts. On a <u>billed</u> basis (including total revenues) this percentages reflects a 4.59% proposed increase.

Q. What guidance has the WUTC Commission provided in recent years as to various "tools" available to it for determining the appropriate ratemaking

adjustments to achieve the objective of providing a utility the opportunity to recover its costs and earn a fair return?

A. This Commission provided guidance in Avista's 2016 general rate case, Dockets UE-160228/UG-160229, Order 06, at paragraph 79, where it noted that it is tasked with determining an appropriate balance between the needs of the public to have safe and reliable electric and natural gas services at reasonable rates, and the financial ability of the utility to provide such services on an ongoing basis.[5]

To accomplish this, the Commission identified (Order 06, paragraph 82) certain "tools" they may consider:

> While the Commission traditionally has described its ratemaking practice as being based on the historical test year, a key operative part of this description is 'based on.' In point of fact, our practice is quite forward looking and in actuality a process sometimes referred to as a 'hybrid test year.' The Commission, for example:
>
> - Approves pro-forma adjustments to test-year costs when the adjustments are adequately supported. The Commission retains significant discretion to apply flexibly the requirements that *pro forma* adjustments be known and measurable, used and useful, and matched to offsetting factors. The Commission has not established bright-line standards governing the timing or the number of adjustments that can be accepted in a given case, and has not established a minimum size for *pro forma* adjustments to be recognized.
> - May allow new generation plant or other infrastructure in rate base even when the new facilities are placed in service subsequent to the end of the test period. The more certain the timing of infrastructure being in service, that is used and useful, and the more certain the costs, the more likely the post-test period rate base will be approved.
> - May approve end-of-period rate base when this is shown to be appropriate.

[5] The governing statutes require the Commission to determine results that establish "fair, just, reasonable and sufficient" rates (RCW.80.28.010), which mean: "rates that are fair to customers and to the Company's owners; just in the sense of being based solely on the record developed in a rate proceeding; reasonable in light of the range of possible outcomes supported by the evidence; and sufficient to meet the needs of the Company to cover its expenses and attract necessary capital on reasonable terms." (emphasis added) (Order 06, par. 79)

- May approve hypothetical capital structures to improve a utility's financial condition.

Therefore, as will be discussed further in my testimony, as well as other Company witnesses (i.e. Ms. Schuh, Mr. Thies and Mr. Vermillion), the Company has included various "tools," which are recognized by this Commission, in this proceeding to reduce regulatory lag, and to ensure the opportunity (not a guarantee) by the Company to earn its proposed rate of return – mainly: 1) adjusted historical test year results to EOP net plant; and 2) use of a hypothetical capital structure of 50% equity and 50% long-term debt.[6]

Q. What guidance did the Commission give regarding its development of and acceptance of multi-year rate plans?

A. In Avista's 2016 rate case, the Commission stressed that any escalation over time must begin with development of a modified historical test year with pro-forma plant additions.[7] This is the approach Avista has used in this case, by developing the revenue requirement for the first year by pro-forming the 2018 historical test year. Next we used essentially the same "rigorous trend analysis" as previously characterized by the Commission in its 2016 Order to develop rates for year 2.[8] And, as discussed below, the analysis includes "mechanisms that result in a reasonable sharing of risks between shareholders and ratepayers ….," as instructed by the Commission.[9]

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[6] Short-term debt was excluded from the debt component, resulting in a capital structure of 50% equity / 50% debt. This is consistent to the approach used in Avista's Idaho and Oregon jurisdictions, where short-term debt is excluded to determine the appropriate capital structure. Both Idaho and Oregon currently employ a 50% equity component for Avista.

[7] See Washington Utilities and Transportation Commission, Order 06, Dockets UE-160228 and UG-160229 (hereinafter the 2016 Order or Case), ¶62.

[8] *id.* ¶75

[9] *id.*

Finally, the Commission in its 2016 Order said at ¶76:

> "A future proposal for a multi-year rate plan such as that approved for Avista in 2012, or for PSE in 2013, for example could include both updated rates as a starting point and rate escalator one year later, or escalation annually for two or three years, subject to reporting requirements, and, perhaps, an earnings test or sharing mechanism," (emphasis added)

All of these elements are satisfied in this filing.

Q. In April 2018, however, didn't this Commission reject the Company's proposed Three-Year Rate Plan?

A. Yes, it did, based on the unique circumstances of that case. In its April 2018 Order[10] at ¶47, however, it noted a multi-year rate plan remains a "tool":

> "Multi-year rate plans are a tool that the Commission has used in prior rate cases to stop the annual cycle of rate cases, halt attrition of the Company's earnings, and remove the risk associated with regulatory lag.[11] We continue to welcome use of multi-year rate plans in appropriate circumstances to control the seemingly unending, annual filings of rate cases." (emphasis added)

It was just not appropriate "at this time" (April 2018), because of surrounding "circumstances" – i.e., the Tax Cuts and Jobs Act ("TCJA"), the then-pending Hydro One Merger, and Avista's filed depreciation studies that included, among other things, changes to depreciation for Colstrip Units #3 and #4.

As discussed by Mr. Vermillion, the issues related to the TCJA and Hydro One merger have been resolved, and the issues related to depreciation of Colstrip has been included in this case, at the direction of the Commission,[12] as discussed later in my

[10] See, WUTC v. Avista, Docket No(s) UE-170485 and UG-170486, Order 07, (hereinafter 2017 Order or Case)

[11] See, WUTC v. Pacific Power & Light Company, Docket UE-152253, Order 12 (Sept. 1, 2016) and WUTC v. Puget Sound Energy, Dockets UE-121607 and UG-121705 et al, Order 07 (June 25, 2013).

[12] Dockets UE-180167 and UG-180168, Order 04 (Modified), ¶29.

testimony. Even though the 2017 rate plan was rejected, the Commission was quick to note that it "doesn't reflect a change in our recognition of the value of multi-year rate plans either to end the cycle of annual rate filings or to support the utilities efforts at efficiency." (2017 Order, at ¶51)

Q. In its 2016 Order, supra, at ¶76, the Commission noted that a multi-year rate plan could be "subject to reporting requirements, and, perhaps, an earnings test or sharing mechanism." Please explain how the Company proposes to meet these requirements.

A. Included in Avista's Two-Year Rate Plan proposal are "checks and balances" to ensure that retail rates are fair for customers throughout the Two-Year Rate Plan. Through the existing electric and natural gas Decoupling Mechanisms, Avista is subject to separate one-way earnings tests for each of its Washington electric and natural gas operations. As discussed by Company witness Mr. Ehrbar, as a part of this general rate case, Avista is seeking to extend its electric and natural gas decoupling mechanisms through March 31, 2025, and as a part of that request would keep the current one-way earnings test in effect. If Avista were to over-earn during the Two-Year Rate Plan, Avista would share half of the overearnings, protecting customers. However, if Avista under-earns, there is no corresponding protection for the Company under these circumstances; Avista would simply absorb the shortfall.

In addition, as discussed by Ms. Schuh, the Company is proposing to provide additional information for any 2019 electric and natural gas projects included in this case for Rate Year 1 that have not transferred to plant by the time Staff and other parties have completed their review, and the Company is also proposing to provide a capital report providing year-end 2020 capital projects that are in-service prior to Rate Year 2.

Specifically for Rate Year 1, of the 20 discreet 2019 "major projects" that have <u>not</u> transferred to service, or are not complete by the time Staff and other party testimony is due in this case, Avista will supplement the record by providing an updated transfers-to-plant listing prior to the effective date of year one rates. In addition, before the rate-effective date of April 1, 2020 the Company will provide a signed affidavit of the three capital witnesses in this case, under the penalty of perjury, attesting to the fact that each of the projects have transferred to plant-in-service, and are used and useful for customers. This additional support, will serve to validate that such plant is, in fact, in-service, and will provide the Commission assurance that the pro forma level of capital included for Rate Year 1 is serving customers prior to and during the rate year.

For Rate Year 2 (beginning April 1, 2021), the Company is proposing to file with this Commission a Washington Electric and Natural Gas Capital Report by February 15, 2021, which will include: 1) a summary report of actual capital additions (i.e. transfers-to-plant-in-service) and actual year-end (end of period) net plant balances as of December 31, 2020; 2) a final results of operations report (normally filed with the Commission) showing the net plant level for Washington electric and natural gas at December 31, 2020; and 4) a signed affidavit from the three capital witnesses in this case (Mr. Thackston, Ms. Rosentrater, and Mr. Kensok), attesting to the fact that these projects have transferred to plant in-service, and are used and useful to customers. This report will provide an opportunity for review of the level of net plant in-service prior to new rates going into effect on April 1, 2021.

The capital reporting information for Rate Year 2 would provide assurance to the Commission that the rate increases approved effective April 1, 2021 would include a level of net utility plant that is actually in-service serving customers prior to new rates going into effect. In addition, if the capital reporting information shows that the level of plant in service at the beginning of Rate Year 2 will no longer support the proposed step increase, the Commission would have an opportunity to make modifications prior to rates going into effect, and reduce the revenue requirement accordingly.[13] An actual prudency determination on such plant, however, can wait until the next general rate case.[14]

III. PROPOSED REVENUE AND PERCENTAGE INCREASES FOR TWO-YEAR RATE PLAN

Q. Please summarize the proposed electric and natural gas revenue increases proposed by the Company in this case.

A. Table No. 1 below provides a summary of the proposed Two-Year Rate Plan revenue increases and percentage increases.

[13] The level of net plant approved for Rate Year 2 would be based on the final net plant after ADFIT balance approved for Rate Year 1, multiplied by the "Net Plant After ADFIT" Revenue Growth Rate Category (discussed in Section VII. Derivation of Revenue Growth Rate) ultimately approved by the Commission, to arrive at a level of net plant after ADFIT balance.

[14] The use of a subsequent prudency review in the next GRC was employed by the Commission in WUTC v. PSE, Docket Nos. UE-180899 & UG-180900 (Order 05) when approving the settlement, the Commission stated at ¶26:

> We acknowledge the inherent difficulty of conducting a prudence review in the short timeframe afforded in this expedited filing and agree that deferring prudence reviews until the Company's next general rate case is a reasonable solution that will allow all parties and the Commission to conduct a more thorough analysis.

Table No. 1: Proposed Electric and Natural Gas Two-Year Rate Plan

Washington Electric and Natural Gas Two-Year Rate Plan Summary of Revenue Requirement (000s) and % Increases April 1, 2020 - March 31, 2022			
Service		**(April 1, 2020 - March 31, 2021)**	**Rate Year 2 (April 1, 2021 - March 31, 2022)**
WA Electric	**Revenue Requirement**	**$ 45,775**	**$ 18,927**
	% Base	**9.12%**	**3.46% (1)**
	% Billed	**8.82%**	**3.35%**
WA Natural Gas	**Revenue Requirement**	**$ 12,935**	**$ 6,456**
	% Base	**13.80%**	**6.05% (1)**
	% Billed	**10.12%**	**4.59%**

(1) Revenue increases for Rate Year 2 are proposed to be implemented through Schedule 96 and 196, and not through a change to base tariffs, as discussed by Company witness Mr. Miller.

As noted in Table No. 1 above, the proposed base electric increase, effective April 1, 2020, is $45.8 million or 9.12% (8.82% on a billed basis). The base natural gas increase, effective April 1, 2020, is $12.9 million or 13.80% (10.12% on a billed basis).

For Rate Year 2 (April 1, 2021) the proposed revenue increase is $18.9 million or 3.46% (3.35% on a billed basis) for electric operations, and $6.5 million or 6.05% (4.59% on a billed basis) for natural gas operations.

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 to base its need for additional electric and natural gas revenue is the twelve-month period ending December 31, 2018, presented on a pro forma basis. Current authorized rates were based upon the twelve-months ending December 31, 2016 test year utilized in Docket Nos. UE-170485 and UG-170486 (*Consolidated*), adjusted on a pro forma basis.

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

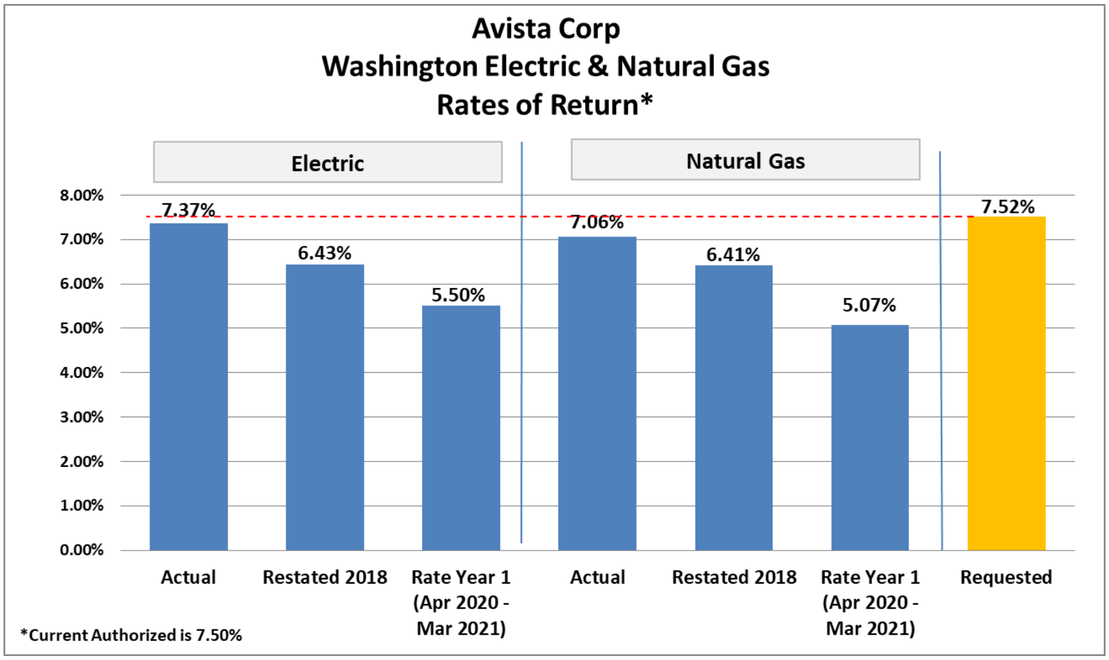
A. The Company's current authorized rate of return for its Washington operations is 7.50%, effective May 1, 2018 for both our electric and natural gas systems, approved in Dockets UE-170485 and UG-170486 (*Consolidated*).

Q. By way of summary, please explain the different rates of return that you will be presenting in your testimony.

A. There are four different rates of return that are provided. The actual ROR earned by the Company during the 2018 test period, the Restated 2018 results for the 2018 test period (representing 2018 normalized Commission Basis (CB) ROR, adjusted to 2018 EOP Net plant basis[15]), the adjusted ROR for Rate Year 1 (April 1, 2020 – March 31, 2021) determined in my Exh. EMA-2 and Exh. EMA-3, and the requested ROR. These returns are shown in Illustration No. 3 below:

[15] Normalized Commission Basis reports filed with the Commission on April 26, 2019 reported CBR results of 7.19% for electric, and 7.39% for natural gas for the twelve-months ended December 31, 2018.

<u>Illustration No. 3: Rates of Return</u>



After taking into account 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 Washington jurisdictional operations for Rate Year 1 are 5.50% and 5.07%, respectively. Both return levels are below the Company's requested rate of return of 7.52%. The incremental revenue requirement necessary to give the Company an opportunity to earn its requested ROR is $45.8 million for the electric operations and $12.9 million for the natural gas operations.

Q. What are the primary factors driving the Company's requested electric and natural gas revenue increases over the Two-Year Rate plan?

A. The increase in overall costs to serve customers is driven primarily by the continuing need to replace and upgrade the facilities and technology we use every day to serve our customers[16], while revenue growth remains low. In particular, Rate Year 1 of the Company's requested rate relief is higher primarily because Rate Year 1, in a sense, is trying to "catch up" on its recovery of capital investment in-service through calendar-year 2018, compared to that currently included in rates (an approximately 18 month period) .

In its last general rate case (GRC), the Commission ultimately allowed only 12 projects (with balances at August 31, 2017) for 2017, to be included in new base rates effective May 1, 2018. The unrecovered capital investment from 2017, plus all of the investment in 2018 results in a net rate base growth[17] of approximately $126.0 million for electric[18] and $66.3 million for natural gas[19] investment included in this filing. In addition, as discussed by Ms. Schuh, the Company has also pro formed certain "major" 2019 electric and natural gas capital projects (20 discreet "major projects"), totaling approximately $84.9 million for electric and $26.5 million for natural gas of gross plant additions.[20] Ms. Schuh

[16] As discussed by Mr. Thies, from 2019 through 2023, the capital expenditure level is expected to remain constant at approximately $405 million annually, for utility generation, transmission and distribution facilities and other requirements.

[17] Net rate base growth includes gross plant additions adjusted/reduced for accumulated depreciation (A/D) and Accumulated Deferred Federal Income Taxes (ADFIT).

[18] In Avista's last GRC, Docket UE-170485, Order 07, Appendix B, page 1, the Commission approved $1.52 billion of electric net rate base. Excluding working capital and deferred debit/credit balances approved of $56.7 million (see Andrews' Exh. EMA-11, page 1, lines 47 and 48), approved net plant after ADFIT totals $1.466 billion. In this case, restated net plant after ADFIT, per Andrews Exh. EMA-2, page 7, line 46 totals $1.592 billion, for an increase in net plant after ADFIT of $126.0 million. As shown in Table No. 2 below, this growth in investment includes electric gross plant additions of $238.9 million, excluding the Company's investment in its Advanced Metering Infrastructure (AMI) project.

[19] In Avista's last GRC, Docket UG-170486, Order 07, Appendix B, page 2, the Commission approved $310.1 million of natural gas net rate base. Excluding working capital and deferred debit/credit balances approved of $14.9 million (see Andrews' Exh. EMA-12, page 1, lines 45 and 46), approved net plant after ADFIT totals $286.1 million. In this case, restated net plant after ADFIT, per Andrews Exh. EMA-3, page 7, line 42 totals $352.4 million, for an increase in net plant after ADFIT of $66.3 million. As shown in Table No. 2 below, this growth in investment includes natural gas gross plant increases of $100.8 million, excluding the Company's investment in its AMI project.

[20] See Andrews' Exh. EMA-2 and Exh. EMA-3, page 9, column "Pro Forma 2019 Major Capital Additions."

will discuss how she arrived at the $5 million threshold for "major projects," which resulted in the 20 discreet projects for 2019 pro formed in this case.

Q. Please explain the major components of the increased electric and natural gas <u>gross</u> plant investment included in this filing?

A. Looking at the changes to "gross" plant in service proposed in this filing, Washington "gross" plant increases by approximately $323.8 million, or 11.7% for electric, and approximately $127.3 million, or 23.8% for natural gas, as compared to what is currently embedded in base retail rates. A breakdown of the incremental electric and natural gas <u>gross</u> plant additions by major component for each year is as follows:

<u>Table No. 2: Gross Plant Additions</u>

Gross Plant Additions (000s)			
	Electric		
Investment	**2017*/2018**	**2019**	**Total**
Generation/Transmission	$ 56,320	$ 27,120	$ 83,440
Distribution	$ 100,320	$ 28,623	$ 128,943
General & Intangible	$ 82,243	$ 29,129	$ 111,372
Total Electric Gross Additions	$ 238,883	$ 84,872	$ 323,755
	Natural Gas		
Investment	**2017*/2018**	**2019**	**Total**
Distribution	$ 60,548	$ 14,592	$ 75,140
General & Underground Storage	$ 40,262	$ 11,926	$ 52,188
Total Natural Gas Gross Additions	$ 100,810	$ 26,518	$ 127,328
*Incremental 2017 capital additions beyond that approved in Dockets UE-170485 & UG-170486.			

Ms. Schuh 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. Other Company witnesses, (<u>i.e.</u> Mr. Thackston regarding production assets; Ms. Rosentrater regarding transmission, distribution and general assets; and Mr. Kensok regarding the costs associated with Avista's Information Service/Information Technology (IS/IT) projects) provide more specific information on certain "major" capital projects during the historical periods 2017 and 2018, as well as the 2019 "major" pro forma capital projects included in this case, describing the need for and timing of these capital projects.

Q. As noted, Ms. Schuh explains the restating and pro forma capital adjustments included in this case. Could you please briefly describe the conclusions drawn by Ms. Schuh regarding the increased capital investment?

A. Yes. As described in Ms. Schuh's testimony, the Company is making substantial levels of capital investment in its electric and natural gas system infrastructure to address customer growth, replacement and maintenance of Avista's aging system, and to sustain reliability and safety. As soon as this new plant is placed in service, the Company must start depreciating the new plant and incur other costs related to the investment. Unless this new investment is reflected in retail rates in a timely manner, it has a negative impact on Avista's earnings, particularly because the new plant is typically far more costly to install than the cost of similar plant that was embedded in rates decades earlier. As plant is completed and is providing service to customers, it is appropriate for the Company to receive timely recovery of the costs associated with that plant.

Q. Ms. Schuh also provides the <u>total</u> expected <u>2019</u> electric and natural gas <u>gross plant additions</u> in her testimony of $164 million for electric and $42.3 million for

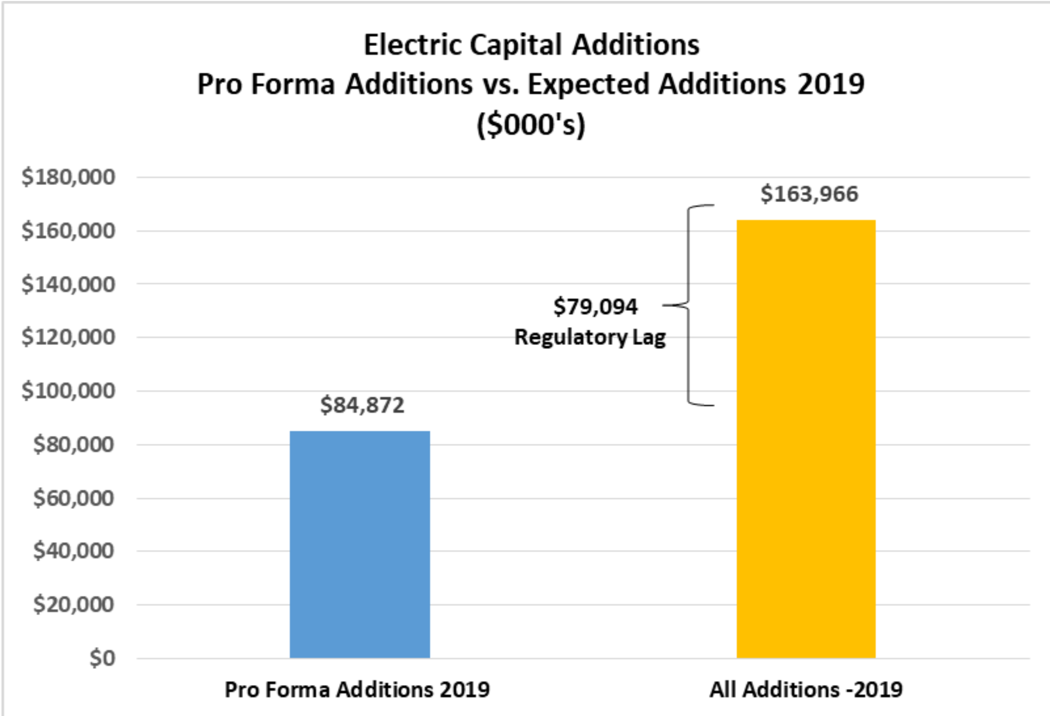
natural gas. How does this compare to what has actually been included in your electric and natural gas Pro Forma Studies?

A. Ms. Schuh explains that the total plant additions planned for 2019 equal approximately $164 million for electric and $42.3 million for natural gas. However, as noted above, by including only the 20 discreet projects versus all 2019 projects, the Company has limited its requested capital additions to $84.9 million for electric and $26.5 million for natural gas. (In this regard, depreciation expense is also understated by any capital additions excluded in this case.) This reduction in 2019 plant additions excluded from this case represents an imposed regulatory lag of approximately $79.1 million for electric and $15.7 million for natural gas.[21]

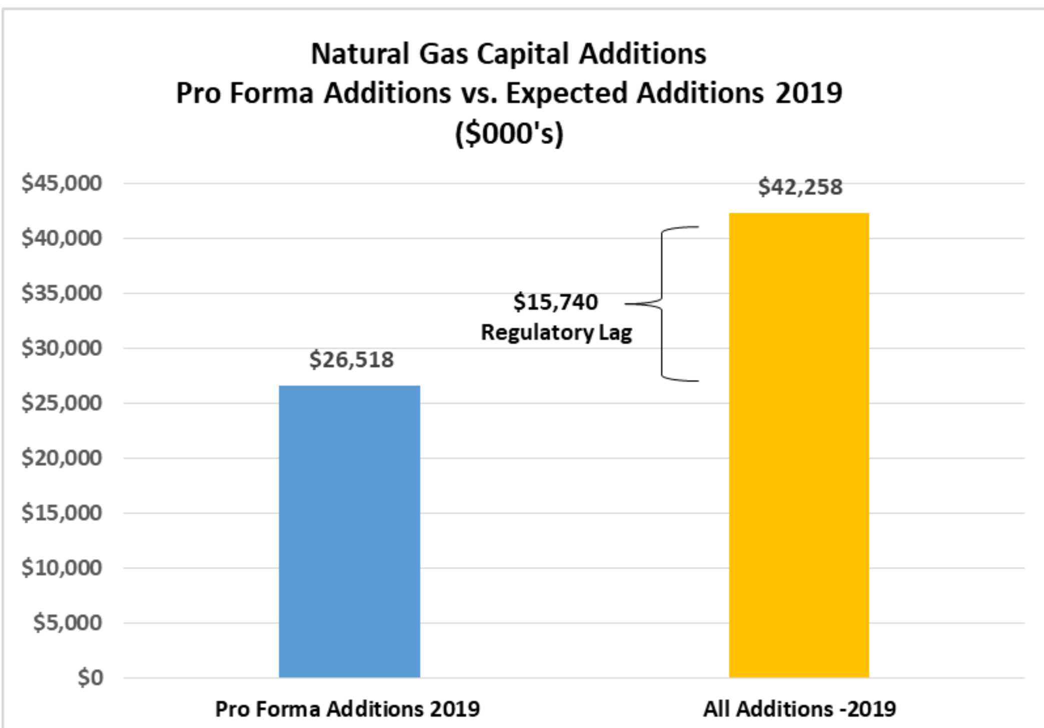
Illustration Nos. 4 and 5 below[22], illustrates this comparison of 2019 pro formed capital additions, versus total planned 2019 capital additions, and the imposed regulatory lag, for electric and natural gas, respectively.

[21] This does not take into effect any additional regulatory lag associated with capital additions from January 1, 2020 to March 31, 2020, prior to rates going into effect April 1, 2020.
[22] Similar illustrations to Illustration Nos. 3 and 4 above also appear in Ms. Schuh's direct testimony (KKS-1T).

<u>Illustration No. 4: Electric 2019 Pro Forma versus 2019 Planned Capital Additions</u>



<u>Illustration No. 5: Natural Gas 2019 Pro Forma versus 2019 Planned Capital Additions</u>



Q. In addition to capital investment, would you also please identify the main components of increased O&M and A&G expense impacting the Company's filed request?

A. Yes. A number of expense items have also increased since the 2016 test year pro forma used in the last rate case. In this case, we are utilizing a 2018 historical test year. However, new base electric rates resulting from this filing are not expected to go into effect until the first half of 2020. Accordingly, the Company has included a number of pro forma adjustments to capture some of the cost changes that the Company will experience from the 2018 test year. For example, as explained later in my testimony, employee benefits such as wages, pension and medical insurance expenses have been pro formed versus 2018 actuals, thereby increasing O&M and A&G expense approximately $5.4 million for electric and $1.6 million for natural gas.[23] Increases in information services and technology (IS/IT) non-labor expenses have also been pro formed beyond 2018 actual expenses, increasing expense approximately $1.9 million for electric and $582,000 for natural gas.[24] As discussed by Mr. Kensok, IS/IT expense increases are primarily caused by <u>increased contractual costs</u> associated with products and services, licensing and maintenance fees, and other costs, necessary to support Company cyber and general security, emergency operations readiness, electric and natural gas facilities and operations support, and customer services.[25]

[23] See Exhs. EMA-2 and EMA-3, page 8, Pro Forma adjustments 3.03 through 3.05.
[24] See Exhs. EMA-2 and EMA-3, page 8, Pro Forma adjustment 3.07.
[25] Exh. JMK-1T.

IV. DERIVATION OF ELECTRIC AND NATURAL GAS PRO FORMA STUDIES

Q. Please explain what is shown in the electric and natural gas Pro Forma Studies, provided as Exhs. EMA-2 and EMA-3?

A. Exhs. EMA-2 (electric) and EMA-3 (natural gas) shows actual and pro forma electric and natural gas operating results and rate base for the pro forma test period for the State of Washington.

Specifically, page 1, of both Exhs. EMA-2 and EMA-3, Column (b), shows 2018 actual operating results and components of the average-of-monthly-average rate base as recorded[26]; column (c) is the total of all adjustments to net operating income and rate base; and column (d) is pro forma results of operations, all under existing rates. Column (e) shows the revenue increase required which would allow the Company to earn a 7.52% rate of return. Column (f) reflects pro forma operating results with the requested increase of $45,775,000 for electric and $12,935,000 for natural gas.

Page 2 of Exh. EMA-2 (electric) and Exh. EMA-3 (natural gas) shows the calculation of the electric and natural gas revenue requirements of $45,775,000 and $12,935,000, respectively, at the requested 7.52% rate of return. This page also shows the percentage base revenue increase for electric of 9.12% and natural gas of 13.8%, as well as the percentage on a billed basis of 8.82% for electric and 10.12% for natural gas.

Q. What does page 3 of Exhs. EMA-2 and EMA-3 show?

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[26] Actual plant rate base (cost, accumulated depreciation and associated DFIT) uses the 2018 AMA balances. Plant rate base is first restated (restated adjustment) to a 2018 End-of-Period (EOP) rate base, and then further adjusted (pro forma adjustment) to include certain 2019 capital projects (20 discreet electric and natural gas projects) completed and transferred to plant during 2019.

A. Page 3 shows the Cost of Capital and Capital Structure included in the Pro Forma Studies, including: 1) 50% Common Equity / 50% Debt capital structure[27]; 2) Return on Equity of 9.9%; and 3) cost of debt of 5.15%, resulting in an overall Rate of Return (weighted average cost of capital) of 7.52%. Mr. Thies discusses the Company's proposed rate of return and the pro forma capital structure utilized in this case, while Company witness Mr. McKenzie provides additional testimony related to the appropriate return on equity for Avista.

Q. Please explain further the Company's proposed capital structure of 50% equity and 50% debt.

A. The Company is proposing an adjusted capital structure of 50% common equity and 50% debt. This is revised from the current authorized common equity level of 48.6% long-term debt, 2.9% short-term debt and 48.5% common equity. The 50% equity also impacts the pro forma weighted cost of debt, reducing the tax benefit of debt interest and reducing net operating income. The overall result of using a 50% equity ratio increases the electric revenue requirement requested in this case for electric by $1.97 million, and natural gas by $458,000 for Rate Year 1.

Q. Why is Avista proposing to exclude short-term debt from the capital structure calculation in this case?

A. As explained above, the results from the electric and natural gas Pro Forma Studies, without certain adjustments (i.e. adjusted historical 2018 test year results to EOP net

[27] As discussed further by Mr. Thies, the Company has requested an adjusted capital structure of 50% Equity / 50% Debt, which results in the proposed cost of capital of 7.52%.

plant, and use of a hypothetical capital structure of 50% equity and 50% long-term debt), will not yield the rate relief necessary to provide the Company the opportunity to earn the proposed ROR requested in this case. One of the rate making "tools" identified by this Comission that can be used to arrive at an end result that provides sufficient revenues is the use of an adjusted capital structure.[28]

Furthermore, as explained by Mr. Thies, maintaining a 50% common equity ratio, excluding short-term debt, has several benefits for customers. As the Company accesses the debt capital market to raise funds, a solid financial profile will assist us in accessing funds on reasonable terms in both favorable financial markets and when there are disruptions in the financial markets. The Company's proposed 50% equity ratio solidifies our current credit ratings and moves us closer to our long-term goal of moving our corporate credit rating from BBB to BBB+, consistent with the natural gas and electric industry average, providing more stability for the Company, and an equity layer that appropriately balances safety and economy for customers.

Q. Is this approach used in other jurisdictions?

A. Yes. In both Avista's Idaho and Oregon jurisdictions the Commissions for many years have approved a capital structure calculated excluding short-term debt. This approach improves Avista's opportunity to earn its allowed ROR in those jurisdictions. Mr. Thies provides this calculation in his testimony.

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[28] The WUTC acknowledged at page 181 of its Order 08 in Docket No. UE-111048 and UG-111049 of Puget Sound Energy's rate proceeding, the consideration of adjustments to rate base beyond the historical test period by stating they were open to considering "Use of plant accounts (rate base) measured at the end, or subsequent to the end of the test-year rather than the test-year average," and their openness to consider <u>an "upward adjustment to the equity share in the capital structure</u>." (emphasis added)

Q. Would you now please explain page 4 of Exhs. EMA-2 and EMA-3?

A. Yes. Page 4 shows the derivation of the net-operating-income-to-gross-revenue-conversion factor. The conversion factor takes into account uncollectible accounts receivable, Commission fees and Washington State excise taxes. Federal income taxes are reflected at 21%.

Q. Now turning to pages 5 through 9 of Exhs. EMA-2 and EMA-3, would you please explain what those pages show?

A. Yes. Page 5 of both Exhs. EMA-2 and EAM-3 begins with actual operating results and rate base for the twelve-months-ending December 31, 2018 test period on an AMA basis in column (1.00). Individual normalizing and restating adjustments that are standard components of our annual reporting to the Commission begin in column (1.01) on page 5 and continue through column (2.19) on page 7 for electric, and continue through column (2.15) on page 7 for natural gas. For electric, individual pro forma adjustments begin in column (3.01) on page 8 and continue through column (3.14) on page 9. For natural gas, individual pro forma adjustments begin in column (3.01) on page 7 and continue through column (3.12) on page 9. The final column on page 9 for both electric and natural gas is the total pro forma operating results and rate base for the pro forma test period.

The testimony that follows explains the reason and theory for each of the electric and natural gas Commission Basis, restating and pro forma adjustments, as well as the calculation, where appropriate. These adjustments were prepared consistent with current regulatory principles and the manner in which they have been addressed in recent cases (i.e., UE-170485 and UG-170486), unless otherwise noted. The Company has also provided workpapers, both in hard copy and electronic formats, which include additional details and calculations related to each of these adjustments.

V. STANDARD COMMISSION BASIS AND RESTATING ADJUSTMENTS

Q. Please explain each of the Commission Basis and restating adjustments included, starting on page 5 of both Exhs. EMA-2 and EMA-3, the reason for the adjustment and its effect on the Washington electric and natural gas net operating income and/or rate base for the historical test period.

A. Starting on page 5 of Exhs. EMA-2 and EMA-3, Column **(1.00)** the **Results of Operations** reflect the Company's actual operating results and total net rate base experienced by the Company for year ending December 2018 on an AMA basis. Columns following the Results of Operations column (1.00), (columns (1.01) – (2.19) for electric and columns (1.01) – (2.15) for natural gas) mainly reflect normalizing and restating adjustments necessary to restate the actual results based on prior Commission orders, reflect appropriate annualized expenses, correct for errors, or remove prior period or non-recurring amounts reflected in the year ending December 2018.[29] A summary of each adjustment follows:

The first column on page 5, Electric Adjustment (1.01) and Natural Gas Adjustment (1.01), entitled **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

[29] Included with the electric and natural gas restating adjustments is an End-Of-Period (EOP) 2018 Net Plant adjustment, adjusting net plant from an average-of-monthly-average (AMA) 2018 historical test year balance to a 2018 EOP net plant historical test-year balance, similar to that approved by the WUTC in Avista's last general rate case proceeding (Docket Nos. UE-170485 and UG-170486).

my workpapers provided with the Company's filing. ADFIT reflects the deferred tax balances arising from 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 Washington rate base is a reduction of $1,946,000 for electric and $1,247,000 for natural gas. The effect on Washington net operating income (NOI) due to the Federal Income Tax (FIT) expense on the restated level of interest on the change in rate base is a reduction of $11,000 electric and a reduction of $7,000 natural gas.[30]

The next column on page 5, 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 net operating income (NOI) impact. The net impact on a consolidated basis of this adjustment decreases Washington electric rate base by $7,000 and decreases NOI by $28,000. For Washington natural gas, this adjustment also decreases rate base by $7,000, and decreases NOI by $8,000.

Adjustments included in the Deferred Debits and Credits consolidated adjustment are those necessary to reflect restatements from 2018 actual results (included in column 1.00 "Per Results of operations"), based on prior Commission orders, and are explained below.

The following items are included in the consolidated adjustment:

- **Colstrip 3 AFUDC Elimination (electric)** reflects the reallocation of rate base and depreciation expense between jurisdictions. In Cause Nos. U-81-15 and U-82-10, the UTC 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

[30] The net effect of Federal Income Tax (FIT) expense on the restated level of interest expense due to a change in rate base, is shown within each individual adjustment. The restated debt interest impact per individual rate base adjustment can be seen on line 28 of Exh. EMA-2.

CWIP was allowed in rate base in Case U-1008-144 by the Idaho Public Utilities Commission ("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.

- **<u>Colstrip Common AFUDC (electric)</u>** is associated with the Colstrip plants in Montana, and impacts rate base. Differing amounts of Colstrip common facilities were excluded from rate base by this Commission and the IPUC 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 IPUC. 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 Washington and Idaho jurisdictions. Amortization expense associated with the Colstrip common AFUDC is charged directly to the Washington and Idaho jurisdictions through Account 406 and is a component of the actual results of operations. The rate base amount included in the results of operations accurately reflects the average-of-monthly-averages amount for the test period. No adjustment from that recorded within results of operations is necessary.

- **<u>Kettle Falls Disallowance (electric)</u>** reflects the Kettle Falls generating plant disallowance ordered by this Commission in Cause No. U-83-26. The disallowed investment and related depreciation, FIT expense, accumulated depreciation and accumulated deferred FIT on an AMA basis are accurately reflected in the results of operations column, removing these amounts from actual results of operations. No adjustment from that recorded within results of operations is necessary.[31]

- **<u>Settlement Exchange Power (electric)</u>** reflects the rate base associated with the recovery of 64.1% of the Company's investment in Settlement Exchange Power. The 64.1% recovery level was approved by the Commission's Second Supplemental Order in Cause No. U-86-99 dated February 24, 1987. Amortization expense and deferred FIT expense recorded during the test period are accurately reflected in results of operations. The production rate base and accumulated deferred FIT amounts within results of operations are reflected on a twelve-month ending

[31] This deferred item is fully amortized as of December 2018. See pro forma adjustment 3.02 discussion below for the removal of this deferred item.

December 31, 2018 test period AMA basis. No adjustment from that recorded within results of operations is necessary.[32]

- **Restating CDA Settlement Deferral (electric)** reflects the net assets and DFIT balances associated with the 2008/2009 past storage and §10(e) charges deferred for future recovery are reflected on a twelve-months ending December 31, 2018 test period AMA basis within results of operations. A ten-year amortization expense, as approved in Docket No. UE-100467, of the CDA Settlement Deferral is accurately reflected in results of operations. No adjustment from that recorded within results of operations is necessary.

- **Restating CDA/SRR (Spokane River Relicensing) CDR Deferral (electric)** the net assets associated with the CDA Tribe settlement 4(e) Spokane River relicensing conditions deferred for future recovery are reflected on a twelve-months ending December 31, 2018 test period AMA basis within results of operations. A ten-year amortization expense of the CDA/SRR CDR Deferral, as approved in Docket No. UE-100467 is accurately reflected in results of operations. No adjustment from that recorded within results of operations is necessary.

- **Restating Spokane River Deferral** reflects the net asset and DFIT balances related to the Spokane River deferred relicensing costs deferred for future recovery are reflected on a twelve-months ending December 31, 2018 test period AMA basis within results of operations. A ten-year amortization expense of the Spokane River Deferral, as approved in Docket No. UE-100467, is accurately reflected in results of operations. No adjustment from that recorded within results of operations is necessary.

- **Restating Spokane River PM&E Deferral (electric)** reflects the net asset and DFIT balances related to the Spokane River deferred PM&E costs deferred for future recovery are reflected on a twelve-months ending December 31, 2018 test period AMA basis within results of operations. A ten-year amortization expense of the Spokane River PM&E Deferral, as approved in Docket No. UE-100467, is accurately reflected in results of operations. No adjustment from that recorded within results of operations is necessary.

- **Tax Reform Non-Plant Excess ADIT Regulatory Liability** reflects the regulatory liability associated with the tax reform non-plant excess accumulated deferred income tax (ADIT) liability. Because of the Tax Reform Act passed in 2017, all deferred tax assets and liabilities were revalued to represent the federal tax rate of 21% instead of the 35% federal tax rate that had been recorded. In the Company's last GRC (Dockets UE-170485 & UG-170486), the Commission

[32] This deferred item is fully amortized as of September 2019, prior to the proposed April 1, 2020 to March 31, 2021 effective period. See pro forma adjustment 3.02 discussion below for the removal of this deferred item.

approved setting aside this tax benefit for future use, therefore, the Company began accruing interest on the balance in May 2018. Because of this, the adjustment to rate base was reduced to zero in May of 2018. This regulatory liability was adjusted to reflect the AMA balance of this liability in 2018 for restated purposes. The net impact of this adjustment decreases Washington electric rate base by $7,000 and natural gas rate base by $7,000.[33]

- **Restating Montana Riverbed Lease (electric)** reflects the costs associated with the Montana Riverbed lease settlement. In this 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 Docket No. UE-072131. In Docket No. UE-080416 (see Order No. 08), 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 on January 1, 2009. The 10-year amortization of the first two annual payment deferral expired on December 31, 2016, therefore there is no rate base balance. The ten-year amortization expense of the Montana Riverbed Lease Deferral, as approved in Docket No. UE-072131, is accurately reflected in results of operations. The lease continues on a year-to-year basis, with payments being paid into escrow until resolution of pending litigation.

- **Customer Advances (electric and natural gas)** decreases rate base for money advanced by customers for line extensions, as they will be recorded as contributions in aid of construction at some future time. No adjustment from that recorded within results of operations is necessary.

- **Customer Deposits (electric and natural gas)** reduces electric and natural gas rate base by the average-of-monthly-averages of customer deposits held by the Company, as ordered by this Commission in Docket UE-090134 and UG-090135. The reduction to rate base is accurately reflected in results of operations. Therefore no adjustment is necessary to rate base. The corresponding interest paid on customer deposits is reclassified to utility operating expense, at the current UTC interest rate of 1.79%. The effect on Washington is an increase in expense of $35,000 for electric and $10,000 for natural gas.

In summary, as noted above, the net impact on a consolidated basis of the adjustments described above decreases Washington net operating income for electric and

[33] To reflect the balance of $0 as of May 2018, the Company removed the 2018 AMA regulatory liability balance of $2.1 million in pro forma Adjustment 3.02, discussed below.

natural gas by $28,000 and $8,000, respectively. Rate base is also reduced by $7,000 for both Washington electric and Washington natural gas. (Electric Adjustment (3.02) Pro Forma Deferred Debits, Credits & Regulatory Amortizations, explained below, adjusts certain items listed above to reflect pro forma (April 1, 2020 – March 31, 2021) levels of deferred debits and credit balances and amortization expense as ordered in prior cases.)

Continuing on page 5 of Exh. EMA-2 and EMA-3, column (1.03) **Working Capital** **-** electric and natural gas working capital is included in the Company's Results of Operations column (1.00) on a twelve-months ending December 31, 2018 test period AMA basis. 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 approved by the Commission in the Company's last electric and natural gas general rate cases, Docket Nos. UE-170485 and UG-170486. The working capital balance, as recorded, is accurately reflected in results of operations, therefore, no adjustment from that recorded within results of operations is necessary.

Remove AMI Rate Base, column (1.04) electric and natural gas, reflects the removal of rate base and expense included in the Company's Results of Operations column (1.00) on a twelve-months ending December 31, 2018 test period AMA basis, associated with the Company's investment in its Advanced Meter Infrastructure (AMI) project. Per Order 01 in Docket Nos. UE-170327 and UG-170328, the Commission approved the deferral of depreciation expense for the Company's investment in its AMI project. Balances deferred, and the Company's investment in AMI will be reviewed upon completion of the project for prudency and recovery in a future general rate case proceeding. The effect of these adjustments on Washington rate base is a reduction of $19,166,000 for electric and $6,038,000 for natural gas. The effect on Washington net operating income (NOI) is a reduction of $103,000 for electric and a reduction of $33,000 for natural gas.

Eliminate B & O Taxes, column (2.01) electric and natural gas, eliminates the revenues and expenses associated with local business and occupation (B & O) taxes, which the Company passes through to its Washington customers. The adjustment eliminates any timing mismatch that exists between the revenues and expenses by eliminating the revenues and expenses in their entirety. B & O taxes are passed through on a separate schedule, which is not part of this proceeding. The effect of this adjustment is to decrease Washington electric and natural gas net operating income by $70,000 and $11,000, respectively.

Restate Property Tax, column (2.02) electric and natural gas, restates accrued property tax during the test period to actual property tax paid during 2018. Property tax expense for 2018 was based on actual plant balances as of December 31, 2017. The effect of this adjustment increases Washington electric net operating income by $427,000, and decreases Washington natural gas net operating income by $2,000. Adjustment (3.08) Pro Forma Property Tax, explained below, increases property tax expense to reflect the levels of expense expected during the rate year, based on plant balances as of December 31, 2018.

Uncollectible Expense, column (2.03) electric and natural gas, restates accrued expense to the actual level of net write-offs for the test period. The effect of this adjustment decreases Washington electric net operating income by $557,000, and increases Washington natural gas net operating income by $253,000.

Regulatory Expense, the last adjustment on page 5, column (2.04) electric and natural gas, restates recorded regulatory expense for twelve-months ended December 31, 2018, to reflect the UTC assessment rates applied to revenues for the test period, and for electric, the actual levels of FERC fees paid during the test period. The effect of this adjustment increases electric net operating income by $14,000, and increases natural gas net operating income by $40,000.

Q. Please turn to page 6 of Exhs. EMA-2 and EMA-3 and explain the adjustments shown there.

A. Turning to page 6 of Exhs. EMA-2 and EMA-3, the first adjustment in column (2.05) **Injuries and Damages**, restates electric and natural gas accrued injuries and damages expense with a six-year rolling average of injuries and damages payments not covered by insurance. As a result of the Commission's Order in Docket No. U-88-2380-T, the Company changed to the reserve method of accounting for injuries and damages not covered by insurance. The effect of this adjustment decreases electric and natural gas net operating income by $20,000 and $43,000, respectively.

FIT/DFIT/ITC Expenses, column (2.06) electric and natural gas, reflects the appropriate level of FIT and DFIT calculated at 21% within Results of Operations for the year ending December 31, 2018. For electric, this adjustment also reflects the appropriate level of investment tax credits (ITC) on qualified generation. The DFIT adjustment required for electric increases net operating income by $36,000. Natural gas FIT and DFIT are appropriately reflected in results of operations, therefore no adjustment is necessary.

<u>Office Space Charged to Non-Utility</u>, column (2.07) electric and natural gas, removes a portion of electric and natural gas office space costs[34] based on the relationship of labor hours charged to subsidiary/non-utility activities by employee compared to total labor hours by employee. These percentages are applied to the employees' office space (expressed in square feet) and multiplied by office space costs/per square foot. This restating adjustment is made as a result of the Commission's Third Supplemental Order in Docket No. U-88-2380-T. This adjustment removes the portion of electric and natural gas expense that has not already been reflected in the test period as non-utility. The effect of this adjustment increases electric and natural gas net operating income by $45,000 and $13,000, respectively.

<u>Restate Excise Taxes</u>, column (2.08) electric and natural gas, removes the effect of a one-month lag between collection and payment of electric and natural gas taxes. The effect of this adjustment decreases electric net operating income by $21,000. No adjustment is necessary for natural gas.

<u>Net Gains/Losses</u>, column (2.09) electric and natural gas, reflects a ten-year amortization of net gains realized from the sale of real property disposed of between 2009 and December 31, 2018. This restating adjustment is made as a result of the Commission's Order in Docket Nos. UE-050482 and UG-050483. The effect of this adjustment increases electric and natural gas net operating income by $49,000 and $10,000, respectively.

<u>Weather Normalization (electric)</u>, column (2.10) for electric, normalizes weather

[34] Office space is comprised of office building operating and fixed costs, utilities, administrative, security, HVAC, depreciation and property taxes, as well as other costs related to employee use of phones, laptops, etc.

sensitive kWh sales by eliminating the effect of temperature deviations above or below historical norms. Company witness Ms. Knox is sponsoring this adjustment. The effect of this particular adjustment increases net operating income by $406,000.

Weather Normalization & Gas Cost Adjustment (natural gas), column (2.10), normalizes weather sensitive gas therm sales by eliminating the effect of temperature deviations above or below historical norms. This adjustment also restates therms sold to reflect the weather normalized therms and then reprices the adjusted therms sold based upon the authorized weighted average cost of gas. Mr. Miller is sponsoring this adjustment. The effect of this adjustment increases net operating income by $5,000.

Eliminate Adder Schedule Adjustments, column (2.11) electric and natural gas, removes the impact of the electric and natural gas adder schedule revenues and related expenses which are recovered/rebated by separate tariffs and, therefore, are not a part of base rates. For electric, schedules, such as Schedule 59 Residential Exchange credit, Schedule 75 Decoupling Rebate/Surcharge, Schedule 91 Tariff Rider (DSM), Schedule 92 Low Income Rate Assistance Program Rate, Schedule 93 ERM rebate, Schedule 94 BPA rebate, Schedule 95 Optional Renewable and Schedule 98 REC Revenue Surcharge/Rebate are removed. For natural gas, schedules, such as Schedule 175 Decoupling Rebate/Surcharge, Schedule 191 Tariff Rider (DSM), Schedule 192 Low Income Rate Assistance Program Rate and Schedule 155 Gas Cost surcharge/rebate, are removed. In addition, various accounts associated with the cost of natural gas managed through the PGA deferral mechanism are consolidated into City Gate Purchases in this adjustment.

Ms. Knox (electric) and Mr. Miller (natural gas) sponsor these two adjustments. There is no effect of this adjustment on Washington natural gas net operating income, as the adjustment to expense is equal to the adjustment to revenue. For electric, the removal of most schedules reflect expense that is equal to the adjustment to revenue, however, the removal of the decoupling deferral has the effect of increasing electric net operating income by $1,103,000.

Miscellaneous Restating Non-Utility/Non-Recurring Expenses, column (2.12) electric and natural gas, is the final adjustment on page 5 of Exhs. EMA-2 and EMA-3. This adjustment removes a number of non-operating or non-utility expenses associated with dues and donations, etc., included in error in the Company's electric and natural gas test period actual results, and removes, reclassifies or restates other expenses incorrectly charged between service and or jurisdiction. The Company has removed or restated certain Director and Officer related expenses per Docket Nos. UE-090134 and UG-090135. For instance, director fees and director meeting expenses were reduced by $365,000 electric and $113,000 natural gas expense to reflect 50% of overall expenses in utility operations, and the Company has also removed 10% of total Directors' and Officers' insurance expense to reflect the non-utility/subsidiary portion. Finally for expenses, the Company has also removed the utility-portion of the Company's Long Term Incentive Plan (LTIP) related to restricted shares expense, as ordered in Docket No. UE-150204 and UG-150205 in the amount of $764,000 electric and $236,000 natural gas expense. The net reduction of these expenses for electric and natural gas is approximately $1,193,000 and $380,000, respectively. Lastly, in this adjustment the Company removes from "other revenue" amounts associated with the prior year 2017 earnings test true-up adjustment (required per our Decoupling Mechanisms) recorded in 2018. Therefore, the overall <u>net</u> impact of this adjustment is an increase to electric and natural gas NOI of $1,237,000 and $390,000, respectively.

Q. To the best of your knowledge, were all expenses associated with the failed merger with Hydro One removed from the Company's electric and natural gas results of operations?

A. Yes. Any costs associated with the proposed merger were charged to <u>non</u>-utility accounts. As a second check, Avista's Regulatory Affairs personnel did a thorough review of its general ledger to verify that no costs were included in this case that were associated with the proposed transaction.

Q. Please continue an explanation for adjustments on page 7.

A. The first adjustment on page 7, **<u>Restating Incentive Expense</u>,** column (2.13) electric and natural gas, restates actual O&M incentive compensation expense recorded in 2018 to reflect a six-year average (2013-2018) of actual payouts. The use of a six-year average of payouts is consistent with Staff's methodology approved by the Commission in Order No. UE-170485 and UG-170486.

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 $1.29 million (system) in operating expenses. Incentive compensation related to financial metrics are excluded from the Company's filing with expenses borne by shareholders. For <u>non-executive officers,</u> the six-year average of incentive compensation expense payout is $6.5 million (system) for O&M metrics designed to drive cost-control, and delivery of safe, reliable service with a high level of customer satisfaction. The net effect of this adjustment, including both executive and non-executive changes, increases NOI by approximately $196,000 for electric and $57,000 for natural gas.

Restate Debt Interest, column (2.14), restates electric and natural gas debt interest using the Company's pro forma weighted average cost of debt included in the pro forma studies of 2.57%, on the Results of Operations level of rate base shown in column (1.00) only, resulting 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 Washington net operating income by $1,140,000 for electric and $249,000 for natural gas.

The Federal income tax effect of the restated level of interest on all other rate base adjustments included in the Company's filing are included and shown as an income impact of each individual rate base adjustment described elsewhere in this testimony.

Eliminate WA Power Cost Deferral (electric), column (2.15), removes the effects of the financial accounting for the Energy Recovery Mechanism (ERM.) The ERM normalizes and defers certain net power supply and transmission revenues and expenses pursuant to the Commission-approved deferral and recovery mechanism. The adjustment removes the ERM rebate revenue as well as the deferral and amortization amounts and certain directly assigned power costs and net transmission costs associated with the ERM. The effect of this adjustment increases net operating income by $9,982,000.

<u>Nez Perce Settlement Adjustment (electric)</u>, adjustment column (2.16), reflects a decrease in production operating expenses. An agreement was entered into between the Company and the Nez Perce Tribe in 1999 to settle certain issues regarding previously owned hydroelectric generating facilities of the Company. This adjustment directly assigns the Nez Perce Settlement expenses to the Washington and Idaho jurisdictions. This is necessary due to differing regulatory treatment in Idaho Case No. WWP-E-98-11 and Washington Docket No. UE-991606. This restating adjustment is consistent with prior dockets since Docket No. UE-011595. The effect of this adjustment increases net operating income by $6,000.

<u>Normalize CS2/Colstrip Major Maintenance (electric),</u> column 2.17, includes an adjustment to normalize major maintenance expense associated with Avista's Colstrip/Coyote Springs II (CS2) thermal projects. In Order 05, page 56, paragraph 153 of Docket No. UE-150204, the Commission ordered the Company, for regulatory purposes, to normalize and recover its major maintenance expense associated with these plants over a three-year period for Colstrip and four-year period for CS2 to match the major maintenance cycles for each plant.

In 2016 through 2018, Colstrip major maintenance occurred totaling approximately $6.8 million system.[35] For regulatory purposes consistent with UE-150204, the regulatory amortization expense level to include in 2018 totals $2.28 million on a system basis. (One-third of 2016 - 2018 Colstrip major maintenance.) The 2018 actual level of expense included within Results of Operations totaled approximately $308,000. To adjust to the current level

[35] For Colstrip, major maintenance typically occurs two out of every three years.

of amortization ($2.28 million), Adjustment 2.16 reflects an increase in expense for Washington's share (65.39%) totaling $1.29 million. The net effect of this adjustment decreases NOI by approximately $1,017,000.[36]

Authorized Power Supply (electric), column (2.18). This adjustment restates the actual power supply costs for the test year ending December 31, 2018 to the level currently authorized in Case No. UE-170485. This adjustment results in a reduction in Washington operating net income of $20,327,000.[37]

Restate 2018 AMA Rate Base to EOP, column (2.18) electric and column (2.15) natural gas, the final adjustment on page 6, reflects net plant after ADFIT as of December 31, 2018 on an AMA basis per results of operations, adjusted to reflect net plant after ADFIT to a 2018 EOP basis per results of operations. Depreciation at December 31, 2018 was also adjusted to reflect for annual depreciation expense. The effect of this adjustment increases electric and natural gas rate base by $61,892,000 and $32,271,000, respectively. This adjustment also decreases electric and natural gas NOI by $2,565,000 and $1,067,000, respectively.

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[36] There were no major maintenance expense projects for CS2 during 2013-2016, therefore, no adjustment is required for CS2.

[37] The Company is not proposing to adjust its power supply base in this filing. As explained further by Company witness Mr. Kalich, in Order 07 of Avista's 2017 general rate case, Docket UE-170485, at ¶160, the Commission stated that baseline adjustments to power supply costs should only be made "in extraordinary circumstances." More specifically, the Commission stated "… the Commission believes the number of recent baseline adjustments is excessive. …Moving the baseline upward or downward in each general rate case results in distorted results. Going forward, the Commission will consider carefully any adjustments to the power cost baseline and change it *only in extraordinary circumstances*." (emphasis added) Given that the Commission's findings in Order 07 are very recent (April 2018), and given that there have not been any extraordinary circumstances since that time as it relates to the Company's power supply portfolio and operations, no further adjustment related to power supply are proposed in the Company's filing. Mr. Kalich, in his testimony, also provides an update on the progress of power supply modeling workshops being held at Commission direction. Representatives from the Commission Staff, Public Counsel and the Alliance of Western Energy Consumers (AWEC), in addition to the Company, have participated in the four workshops held to date.

Q. Please provide an explanation for the final column on page 7, "Restate Total".

A. The last column on page 7, entitled **Restated Total**, subtotals all the preceding columns (1.00) through column (2.19) electric and column (2.15) natural gas. These totals represent actual operating results and rate base plus the standard normalizing adjustments that the Company includes in its annual Commission Basis reports (CBRs). However, the Restated Total column does not represent December 31, 2018 test period results of operation on a normalized commission basis as filed with the WUTC on April 26, 2019. Differences exist related to the following: 1) inclusion of proposed (pro forma) cost of debt (pro forma versus CBR cost of debt[38]) impacting Adjustment 2.14 above; 2) restating power supply expense to <u>annualized</u> authorized Power Supply amounts in electric Adjustment 2.18 (revenue associated with the approved annual authorized level is included in Adjustment 3.01 Pro Forma Revenue Normalization) and 3) the inclusion of Adjustment 2.19 (electric) and 2.15 (natural gas) Restate 2018 AMA Rate Base to EOP.

<u>VI. PRO FORMA ADJUSTMENTS</u>

Q. Please now turn to pages 8 and 9 and explain what is provided there.

A. Starting on page 8 are individual "Pro Forma" adjustments, (3.01) through (3.14) for electric and (3.12) for natural gas. These adjustments pro form costs beyond levels included in the Company's restated 2018 results, and are reflective of costs incurred

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[38] Per the Washington electric and natural gas CBRs, actual cost of debt at December 31, 2018 on an AMA basis was 5.38%.

during Rate Year 1, effective April 1, 2020 and beyond. Each of these adjustments are described below.

The first adjustment on page 8 of Exhs. EMA-2 and EMA-3, is adjustment **<u>Pro Forma Revenue Normalization</u>**, column (3.01), that adjusts electric and natural gas January 2018 through December 2018 test period customers and usage for any known and measurable (pro forma) changes. In addition, the adjustment re-prices billed, unbilled, and weather adjusted usage at the base tariff rates approved for 2018, as if the May 1, 2018 base tariff rates were effective for the full 12-months of the test year. This adjustment also removes the impact of 2018 decoupling deferrals (GRC resets the base), decoupling earnings sharing and associated 2017 Tax Reform deferrals (January – April 2018). For natural gas, this adjustment also eliminates Schedule 150 Gas Cost revenue and the associated cost of purchased gas. Ms. Knox is sponsoring electric adjustment (3.01), which has the effect of decreasing NOI by $993,000. Mr. Miller is sponsoring natural gas adjustment (3.01), which has the effect of increasing NOI by $404,000.

<u>Pro Forma Def. Debits, Credits and Regulatory Amortizations (electric)</u>, column (3.02), adjusts certain electric items included in restating adjustment (1.02), which is included on an AMA 2018 Commission Basis level, to the level in effect for Rate Year 1, beginning April 1, 2020. Specifically, this adjustment revises the following deferred debit and credit deferral balances from AMA 2018 to AMA for the rate period (April 1, 2020 – March 31, 2021), consistent with prior Commission orders[39]: 1) CDA settlement Deferral;

[39] For a description of each deferral item, see discussion provided above for restating adjustment (1.02) Deferred Debits and Credits.

2) CDA/SRR (Spokane River Relicensing) CDR Deferral; 3) Spokane River Deferral; and 4) Spokane River PM&E Deferral. This adjustment also reduces amortization expense and/or removes any remaining regulatory rate base balance related to the expiration of the following: 1) Settlement Exchange Power, 2) Kettle Falls Disallowance and 3) Tax Reform Non-Plant Excess ADIT Liability. Lastly, this adjustment includes the increased expense associated with the annual CPI adjustment for the Montana Riverbed Lease. The effect of this adjustment reduces electric total rate base by $583,000 and increases NOI by $1,746,000.

Pro Forma LEAP Deferral Gas Line Extension (natural gas), column (3.13), adjusts the existing LEAP deferral amortization expense and rate base balance recorded in 2018, to reflect the revised LEAP AMA rate base (net of ADFIT) balance of $6.7 million, and the revised amortization expense of $2.1 million, for Rate Year 1 (April 1, 2020 – March 31, 2021). The effect of this adjustment increases net rate base by $95,000, and decreases NOI by $1,378,000.

On February 25, 2016, per Docket UG-152394, Order 01, the Commission approved the changes to the Company's natural gas line extension tariff Schedule 151, for a temporary three-year period. Specifically, the Commission approved the use of any excess single-family residential line extension allowance as a rebate on customers' purchase and installation of high efficiency natural gas space and/or hot water heating equipment, if the customer is converting to natural gas from another fuel source.

The Commission also approved the Company's proposed ratemaking treatment, allowing the Company to defer, for opportunity for later recovery in rates, the excess line extension allowance paid to Washington residential customers upon conversion to natural gas. The Commission approved a five-year amortization period for balances included in future general rate cases, with a return on the unamortized balance."[40] Per Order 01, the deferral began on March 1, 2016 and expired February 28, 2019.

In the Company's prior GRC (Docket UG-170486), the Commission approved the amortization of the then-deferred balance of $2.9 million as of March 31, 2017. The five-year amortization expense approved was approximately $580,000 annually.

As of February 2019 the total amount deferred over the three-year period was approximately $10.7 million (an incremental amount of $7.8 million). The Company is proposing in this case to amortize the incremental balance over five-years beginning April 1, 2020 through March 31, 2025. The Company will include any trailing deferral balances, if necessary, in future regulatory proceedings.[41]

Q. The next four adjustments (3.03) through (3.05) 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

[40] UG-152394 Avista Petition, ¶ 31
[41] There will be trailing costs deferred beyond February 2019, reflecting customers in the "queue" prior to the expiration of the LEAP program, and completed after February.

including medical and retirement. The overall package is designed to meet the following goals:

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

Each component is carefully considered within the overall package in order to provide total compensation which will be cost-effective for the Company, as well as, attract 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 now explain the pro forma labor and benefit adjustments starting with adjustment (3.03) Pro-Forma Labor Non-Exec on page 8 of Exh. EMA-2 and EMA-3.

A. **Pro Forma Labor Non-Exec,** column (3.03), reflects changes in base pay, which together with pay-at-risk (Short Term Incentive Compensation) is designed to provide competitive compensation in the market place. 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 adjustment (3.04). For <u>non-union</u> employees, the adjustment annualizes the impact of increases effective March 2018, and includes a 3% adjustment for increases which were effective March 2019. The Company has not proposed an increase for non-union employees for 2020 (the rate effective period). <u>Union</u> employee increases are made in accordance with contract terms to annualize the impact of the 3% increase in 2018, and 3% for 2019 and 2020 in accordance with contract terms. The current contract with the IBEW Union 77 (Washington/Idaho) expires on March 25, 2021. The methodology behind this adjustment is consistent with Docket No. UE-150204 and UG-150205. In total, this portion of the adjustment represents an increase in expense of $2,181,226 electric and $684,837 natural gas.

The Company has also included an adjustment to reclassify the amount of 2018 labor expense previously charged during 2018 to non-utility for the Hydro One Merger (Merger) case to utility operations. The time and associated labor costs charged to Merger are not recurring in nature. Those employees who worked on the Merger will resume their previous responsibilities related to utility operations. This portion of the adjustment represents an increase of approximately $255,749 in electric expense, and $45,414 in natural gas expense.

Accounting for both annual increases, as well as the reclassification related to the Merger, the <u>total</u> net effect on expense of this non-executive labor adjustment is $2,436,975 for electric operations and $730,251 for natural gas operations. The overall impact on NOI of this adjustment is a reduction of $1,924,000 for electric and $577,000 for natural gas.

<u>Pro Forma Labor-Executive</u>, column (3.04), reflects actual salary levels approved by the Board of Directors and that are in effect as of March 2019. This salary level is allocated between Utility and Non-Utility based on 2016 levels actual percentages (90% utility /10% non-utility) – this percentage is consistent with the level included in Order No. UE-170485. These percentages are an accurate representation of allocation between Utility and Non-Utility, absent work previously spent on the Hydro One Merger Case. This net impact of this adjustment, is an increase in electric expense of $330,258, and natural gas expense for $102,000.

The Compensation Committee of the Board of Directors (Board) determined and approved the level of executive officer level of base salary effective March 2019, 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 impact of this adjustment reduces NOI for electric by $261,000 and for natural gas by $81,000.

Pro Forma Employee Benefits, column (3.05) electric and natural gas, adjusts the twelve-months ended December 31, 2018 Retirement Plans (401(k) and Pension), and Medical insurance for active employees and for those retired (post-retirement medical) to the expected amount for 2020. Annually, the Company works with independent consultants in order to determine the appropriate level of expense for both the Retirement Plans (Willis Towers Watson) and the Medical Plans (Mercer). The impact of these changes are summarized in Table No. 3 below: [42]

Table No. 3: Benefit Adjustment

Benefit Adjustment	System	O&M	WA Electric	WA Natural Gas
Retirement	$ 6,522,389	$ 3,672,757	$ 1,763,658	$ 535,121
Medical	3,232,006	1,819,943	873,937	265,165
Total	**$ 9,754,395**	**$ 5,492,700**	**$ 2,637,595**	**$ 800,286**

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.

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

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 2.04 and Washington'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, 2018 to reflect what will be in effect during 2019, resulting in an increase in expense of $1,763,658 (electric) and $535,121 (natural gas). Estimates for Pension Plan expense is determined annually by Willis Towers Watson based on the expected return on assets, discount rates and asset value. The primary contributor to this increase in expense is related to a decrease in asset value due to the actual return on assets for 2018 partially offset by a slight increase in the discount rate and the expected long-term return on assets for 2019. 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 2019.[43] We anticipate updates for 2020 to be available sometime in the second or third quarter of 2019, and the Company will adjust pension expense at that time.

In addition, the Company has made changes to the overall retirement plan, discussed

[43] The estimate for 2019 was used as the basis for the Test Year 2020.

below, resulting in an increase in 401(k) expense due primarily to participation. However, decreases in pension expense will reduce overall retirement net expense over the long-term.

Q. Please describe the recent changes to the Company's retirement plan.

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.[44] All actively employed non-union employees that were hired prior to January 1, 2014, and were covered under the defined benefit pension plan at that time, will continue accruing benefits as originally specified in the plan. 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 describe the Medical portion of the Benefit Adjustment included in the Benefits adjustment.

A. The Company's medical portion of the calculation adjusts Medical expense (for both active and post-retirement) for the twelve-months ending December 31, 2018 to

[44] Changes were applicable to Local Union 659 (Southeast Oregon) effective April 1, 2014.

reflect what will be in effect for 2019 resulting in an increase in expense of $873,937 (electric) and $265,165 (natural gas). [45]

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

A. Avista sponsors a self-funded medical plan that provides various levels of coverage for medical, dental and vision as a portion of employee benefits. Annually, medical premiums[46] for the Company are estimated by an independent consultant, Mercer,[47] based on medical trend, which is a combination of utilization (the pattern of use or intensity of services used for a particular timeframe), and the estimated increase in the costs (such as medical services, office visits, medical equipment, etc.) to treat patients from one year to the next. The following factors are taken into consideration in the development of premiums:

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

Actual medical expense will vary from premium cost estimates based on variations in plan utilization and actual components in the medical trend. For the past several years, actual expense has been lower than our premium cost estimates, resulting in lower costs for

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[45] Post Retirement is also based on an estimate from Willis Towers Watson. As such, 2019 is included as the basis for 2020 until a new estimate is available.

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

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

the Company and our customers. Some reasons could 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. We do not anticipate this trend to continue, due primarily to increased utilization rates, price increases and our population profile, resulting in an overall increase in 2019 expense.

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 a decrease in asset value. We anticipate updates for 2020 to be available sometime in the second or third quarter of 2019, and the Company will adjust pension expense, in this case, at that time.

The overall impact of the Pro Forma Employee Benefits adjustment reduces NOI for electric by $2,083,000 and for natural gas by $632,000.

Q. Please continue with your discussion on pro forma adjustments included on page 8.

A. **<u>Pro Forma Insurance Expense</u>,** column (3.06) electric and natural gas, adjusts the 2018 level of insurance expense for general liability, directors and officers ("D&O") liability, and property insurance to the level of insurance expense the Company will experience during the rate year. The amount included for D&O insurance is reduced by 10% per Docket Nos. UE-090134 and UG-090135. The effect of this adjustment decreases NOI by $27,000 for electric and by $9,000 for natural gas.

<u>Pro Forma IS/IT Expense</u>, column (3.07) electric and natural gas, adjusts the actual level of information services and technology expense included in the 2018 test year to that expected during the rate period beginning April 1, 2020. This adjustment includes the incremental costs primarily associated with signed contract for products and services, licensing and maintenance fees, and other costs. 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 services. Mr. Kensok sponsors this adjustment and provides more information within his testimony. The effect of this adjustment decreases NOI by $1,498,000 for electric and by $460,000 for natural gas.

Q. Please continue with your discussion of the Pro Forma adjustments included on page 9 of Exh. EMA-2 and Exh. EMA-3.

A. The first adjustment on page 9 of Exhs. EMA-2 and EMA-3 is **<u>Pro Forma Property Tax</u>,** column (3.08) electric and natural gas, that restates the 2018 level of property tax expense included in adjustment (2.02) Restate 2018 Property Tax, to the level of property tax expense the Company will experience during the rate year. The property on which the tax is calculated is the property value as of December 31, 2018. The effect of this adjustment decreases NOI by $2,811,000 for electric and by $376,000 for natural gas.

<u>Pro Forma Depreciation Expense</u>, column (3.09) electric and natural gas, reflects the revised depreciation rates approved by the Commission in Order 04 of Dockets UE-180167 and UG-180168 on March 25, 2019. Ms. Schuh sponsors this adjustment and provides more information within her testimony. The effect of this adjustment increases NOI by $1,691,000 for electric and by $1,199,000 for natural gas.

<u>Pro Forma 2019 Major Capital Additions,</u> column (3.10) electric and natural gas, reflects increases related to certain 2019 “major” capital additions, together with associated A/D and ADFIT. This adjustment also includes associated depreciation expense for these “major” 2019 additions. For this adjustment, as sponsored and discussed by Ms. Schuh, the determination of “major projects” was based on any project, <u>on a system basis</u>, that was greater than $5 million. The effect of this adjustment increases electric rate base by $81,243,000 and decreases NOI by $3,284,000. For natural gas, this adjustment increases rate base by $25,258,000 and decreases NOI by $1,144,000

<u>Pro Forma O&M Offsets,</u> column (3.11) electric and natural gas, as explained by Ms. Schuh, the Company reviewed large capital additions in 2019 to determine any offsets (e.g., reduced O&M costs, etc.) resulting in rate period reductions effective April 1, 2020. Maintenance records were reviewed to determine whether any specific maintenance costs were incurred in the test period that would be reduced or eliminated by the investment for that capital project. Those reductions in costs were quantified and included as a reduction to O&M. The effect of this adjustment increases NOI by $119,000 for electric and $11,000 for natural gas.

<u>Pro Forma Fee-Free Amortization,</u> column (3.12) electric and natural gas, reflects the annual expense associated with the “fee-free” payment expense incurred during the rate year ($775,000 electric and $497,000 natural gas), as well as the annual amortization expense as a result of amortizing the “fee-free” payments deferred from February 2017 through March 2020 over a two year period (April 1, 2020 through March 31, 2022).

On January 12, 2016, Avista filed with the Washington Utilities and Transportation Commission a petition 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 payment of bills by Washington 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 March 24, 2016 the Commission issued Order 01 in Docket UE-160071 and UG-160072 approving Avista's petition for an order authorizing accounting and ratemaking treatment of its residential fee-free payment program. The fee-free payment program was successfully launched February 19, 2017. Finally, on April 11, 2019, in addition to the approved 36 month deferral period previously approved, the Commission granted Avista a four month extension due to the timing of filing this general rate case.[48]

The Company has paid invoices through January 2019. As of December 2018, $1,360,890 of Washington customer transactions through the fee-free payment program has been deferred. Of the $1,360,890 deferred, $829,754 was deferred for electric customers and $531,136 was deferred for natural gas customers. The Company estimates the amount to be deferred through March 31, 2020 (prior to the start of new rates in this proceeding) to be approximately $1,550,000 for electric and $994,000 for natural gas. Amortization expense of the deferred balance is included in the Pro Forma Fee Free adjustment at

[48] Order 02, Docket UE-160071 and UG-160072.

$775,000 for electric and $497,000 for natural gas, based on a 24-month amortization period.

Avista is also including an adjustment to expense for the fee-free program related to the expected rate year expense of approximately $576,000 for electric customers. Therefore, for electric, the Company has included a total adjustment to expense of $1,351,000 (including $775,000 for the amortization of the deferred balance ($1,550,000 amortized over two years) and approximately $576,000 for the rate year expense (based on $48,015 per month x 12).

For natural gas, Avista is also including an adjustment to expense for the fee-free program related to the expected rate year expense of approximately $370,000 for natural gas customers. Therefore, for natural gas, the Company has included a total adjustment to expense of $867,000 (including $497,000 for the amortization of the deferred balance ($994,000 amortized over two years) and approximately $370,000 for the rate year expense (based on $30,851 per month x 12).[49]

The effect of this adjustment decreases NOI by $1,067,000 for electric and $685,000 for natural gas.

<u>Pro Forma Colstrip Amortization (electric)</u>, column (3.13), reflects the Company's proposed treatment to recover its investment in Colstrip Units 3 and 4 after

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

reflecting an accelerated depreciation rate of 2027.[50] As discussed below in Section VIII. "Proposed Recovery of Colstrip Units 3 & 4 – Reflecting Accelerated Depreciation to 2027," the Company's proposed treatment increases regulatory amortization expense by $1.7 million, decreases depreciation expense by $149,000, and reduces Colstrip net plant by $9.2 million (after including 2019 Colstrip capital additions, offset by the use of remaining 2017 Tax Reform "temporary" tax credits associated with non-plant excess DFIT of $11.7 million). The effect of this adjustment, therefore, decreases NOI by $1,293,000 and total rate base by $9,188,000.

The last adjustment on page 9 of Exh. EMA-2 is **Pro Forma Normalize CS2/Colstrip Major Maintenance (electric)**, column (3.14), reflects an increase to the normalized major maintenance expense included above in restating adjustment (2.17), which reflected normalized Coyote Springs 2 (CS2)/Colstrip major maintenance for the 2018 historical test period. This adjustment reflects the normalized level of major maintenance related to the Company's CS2/Colstrip facilities, expected during the rate period effective beginning April 1, 2020. Normalized major maintenance in this adjustment reflects one-quarter of the 2019 CS2 "Transformer 3" major maintenance ($1.5 million planned maintenance), one-seventh of the 2019 CS2 "Steam Turbine" major maintenance ($1.0

[50] The revenue requirement in this case was completed prior to the finalization of the "100% Clean" legislation, which is expected to be signed into law in early May 2019, requiring the removal of coal in Washington State by 2025. The Company will update its proposed impact of using an accelerated depreciation date of 2025 for its Colstrip assets in Washington after consulting with its Depreciation Consultant, Gannett Fleming, for revised depreciation rates, and our determination of the revised impact to the proposed revenue requirement. Based on preliminary estimates, the Company anticipates the increased Colstrip Regulatory Asset and amortization to reflect a 2025 depreciable life would require an increase in revenue requirement of approximately $236,000, above moving to a 2027 depreciable life as included in this case.

million planned maintenance)[51] and one-third of the 2017 and 2018 Colstrip major maintenance ($3.2 million), or $1.59 million, on a system basis. The result of this adjustment on a Washington-share basis, decreases normalized major maintenance from that included in restating adjustment (2.17) by $449,000,[52] increasing NOI by $355,000.

Q. Please explain the final pro forma column "Pro Forma Total" on page 9 of Exhs. EMA-2 and EMA-3.

A. The final column on page 9 for electric shows the total pro forma operating results (NOI of $93,906,000) and rate base ($1,708,298,000) for the pro forma test period, and the total revenue requirement need for Rate Year 1 of $45,775,000.

The final column on page 9 for natural gas shows the total pro forma operating results (NOI of $20,236,000) and rate base ($398,990,000) for the pro forma test period, and the total revenue requirement need for Rate Year 1 of $12,935,000.

Q. What is provided as page 10, of Exhs. EMA-2 and EMA-3?

A. Page 10 of Exhs. EMA-2 and EMA-3 provides a one-page summary list of all restating and pro forma adjustments by adjustment number and description, with individual NOI and rate base amounts, as well as overall, and the rates of return on an actual, restated and pro forma level, for ease of reference.

[51] Although typically the CS2 major maintenance is amortized over four years, this major maintenance is not expected to be completed again prior to seven years, so the amortization has been included over seven years.
[52] System pro forma level $1.59 million (above) compared to $2.28 million (system restated level from adjustment 2.17), or a reduction of $690,000 system adjustment ($449,000 Washington electric).

VII. DERIVATION OF REVENUE GROWTH RATE

Q. Please explain the purpose of the electric and natural gas Revenue Growth Rate percentages derived by the Company.

A. The electric and natural gas Revenue Growth Rate percentages calculated by the Company were produced to calculate the incremental revenue requirement necessary for Rate Year 2 of the Company's Two-Year Rate Plan. Based on historical growth in expense and plant related data, offset by the growth in annual sales to customers (revenues) between the 2018 test year and Rate Year 1, and consolidated into a weighted average revenue escalation percentage or "Revenue Growth Rate," this growth rate is then applied to the non-energy revenues[53] proposed for Rate Year 1 (effective April 1. 2020) to determine the incremental revenue necessary in Rate Year 2 (effective April 1, 2021).

The derivation of the electric and natural gas Revenue Growth Rate percentages are provided in Exh. EMA-3 (electric) and Exh. EMA-4 (natural gas). As discussed further below, both Revenue Growth Rates were based on historical Commission Basis Results for the calendar period 2014 through 2018, offset by annual sales revenues, producing a reasonable growth escalation rate for Rate Year 2, and representing a level of revenue necessary during the Rate Year 2 effective period to allow the Company to earn its proposed rate of return (7.52%).

As described below, the resulting electric and natural gas Revenue Growth Rate percentages used to determine Rate Year 2 incremental revenues are 4.14% and 6.11%, respectively.

[53] Excludes revenue associated with power supply and natural gas costs.

Q. Please now explain how the 4.14% (electric) and 6.11% (natural gas) Revenue Growth Rates were derived and used to determine Rate Year 2 revenues.

A. The calculation of the Revenue Growth Rates are discussed below and provided in Exhs. EMA-3 (electric) and EMA-4 (natural gas). Page 1 of both exhibits shows the calculation and component of the Revenue Growth Rates used for Rate Year 2, and are recreated in Table No. 4 for electric and Table No. 5 for natural gas below.

As will be explained further, included in each table is: a) the individual "Growth Rate" result for each category for the period 2014-2018; b) the "Revenue Portion of Category," providing the proportion of revenue for each category to cover its cost versus the total non-gas cost revenue amount (excluding energy and gas cost related revenues and expenses); and c) the "Growth Rate %," which is the calculated "Growth Rate %" result for each category determined by multiplying a) times b). Also provided are the "Annual Growth In Sales Revenues," representing the offsetting annual revenue reducing the Growth Rate percentage, resulting in the overall Growth Rate percentage for electric of 4.14% and 6.11% for natural gas.

Table No. 4: Electric Revenue Growth Rate Calculation

Electric Revenue Growth Rate Calculation - Rate Year 2:	(a)	(b)	(c)
Category	Growth Rate 2014-2018	Revenue Portion of Category	Growth Rate % (a) x (b)
Operating Expenses (1)	2.42%	35.55%	0.86%
Depreciation/Amortization(2)	8.34%	21.94%	1.83%
Taxes Other than Income	4.00%	10.05%	0.40%
Net Plant After ADFIT	5.95%	32.46%	1.93%
Annual Growth In Sales Revenue		100.00%	-0.88%
Total Revenue Growth Rate %			**4.14%**
See Exh. EMA- 4, pg. 4 for growth rates and pg. 2 for revenue proportion and annual growth in sales revenue.			
(1) Reflects a 30 basis points efficiency adjustment in O&M expenses.			
(2) The growth rate in depreciation/amortization expense is primarily driven by shorter-lived assets representing a higher proportion of investment in recent years.			

Table No. 5: Natural Gas Revenue Growth Rate Calculation

Natural Gas Revenue Growth Rate Calculation - Rate Year 2:	(a)	(b)	(c)
Category	Growth Rate 2014-2018	Revenue Portion of Category	Growth Rate % (a) x (b)
Operating Expenses (1)	3.99%	39.53%	1.58%
Depreciation/Amortization(1)	11.03%	22.38%	2.47%
Taxes Other than Income	8.36%	7.97%	0.67%
Net Plant After ADFIT	9.11%	30.13%	2.74%
Annual Growth In Sales Revenue		100.00%	-1.34%
Total Revenue Growth Rate %			**6.11%**
See Exh. EMA- 5, pg. 4 for growth rates and pg. 2 for revenue proportion and annual growth in sales revenue.			
(1) Reflects a 30 basis points efficiency adjustment in O&M expenses.			
(2) The growth rate in depreciation/amortization expense is primarily driven by shorter-lived assets representing a higher proportion of investment in recent years.			

Pages 2 – 5 of Exhs. EMA-4 and EAM-5 provide the calculation and description of each column and component provided in Table Nos. 4 and 5 above.

Q. Please explain Page 2 of Exhs. EMA-4 and EAM-5.

A. Page 2 of Exhs. EMA-4 (electric) and EMA-5 (natural gas) starts with the total normalized December 2018 Commission Basis Results (CBR), shown in column labeled "Commission Basis Total,"[54] providing the 2018 CBR net operating income and total rate base, as filed with the Commission on April 26, 2019.

As shown on electric Exh. EMA-4, this column is further adjusted by removing power supply related revenues and expense data shown in column labeled "Remove Authorized Power Supply," producing the electric "Non-Energy Restated Total" results. Natural gas is not further adjusted, as all gas cost related revenues and expenses were removed through previous CBR Restating Adjustments.

These data are further grouped on page 2, to provide the CBR expenses and plant related data grouped in the following categories: 1) net plant after ADFIT; 2) depreciation expense; 3) taxes other than income expense (mainly property taxes); and 4) all other operating expenses, including O&M, customer service, and administrative and general expenses. The proportion of revenue to cover each of these categories, as shown on page 2, is used to determine the percentage or proportion of each category to apply to the individual growth factors of the same category discussed below (column (b) in Table Nos. 4 and 5).

Annual Sales Revenues for the period are also provided here, representing the offsetting annual revenue included within the overall Revenue Growth Rate calculation.

[54] Commission Basis Report results start with actual operating results and rate base for the twelve-months-ending December balance of each calendar year on an AMA basis. Individual normalizing and restating adjustments that are standard components of our annual reporting to the Commission are applied, resulting in each Commission Basis Report result filed with the Commission annually. The end result of the Commission Basis Report is provided in the report, column labeled "CBR Results Restated Total," which subtotals the CBR level net operating income and rate base.

Page 3 of Exhs. EMA-4 and EMA-5, provides data from the annual normalized Commission Basis Reports, showing Washington electric (EMA-4) and natural gas (EMA-5) expenses and rate base for the periods 2014 through 2018.

Page 4 of Exhs. EMA-4 and EMA-5 shows the development of the electric and natural gas adjusted data and balances for the period 2014 through 2018 period, which are used to analyze the annual growth rates of the four rate base and expense categories used in the Revenue Growth Rate. The Revenue Growth Rate percentages are applied to non-energy and non-gas costs only. Therefore it is necessary to remove any energy-related or natural gas-related costs and revenues from the historical data. For electric, the Washington share of the normalized power supply costs and revenues from each year's CBR filing are deducted from the O&M in the historical reports to create equivalent values for our trend analysis. Adjusted results are therefore, presented for the four aggregated Revenue Growth Rate categories: 1) Operating Expenses; 2) Depreciation Expense; 3) Taxes Other Than Income Tax; and 4) Net Plant After Deferred Income tax.

At the bottom of page 4, are the compound growth rates for each category for the period 2014 through 2018, used as the basis for the consolidated Revenue Growth Rate (column (a) in Table Nos. 4 and 5). Explained further below, the Operating Expense Growth Rate produced using the period 2014 – 2018 of 2.72% for electric and 4.29% for natural gas (see bottom of page 4 of Exhs. EMA-4 and EMA-5), <u>is adjusted downward by 30 basis points to reflect an efficiency adjusted electric and natural gas O&M Growth Rate of 2.42% and 3.99%</u>, respectively, as shown in column (a) of Table Nos. 4 and 5.

In addition to the compound growth rates shown on page 4 of both exhibits, are the percentage proportion of each non-energy/non-gas cost revenue requirement category, based on the 2018 restated Commission Basis balances, included in the Revenue Growth Rate calculation. As previously noted, the revenue proportion by category was determined on page 2 of Exhs. EMA-4 and EMA-5 (and shown in column (a) of Table Nos. 4 and 5).

Lastly, also shown on page 4 of Exhs. EMA-4 and EMA-5 is the weighted average calculated Growth Rate percentage for each category, based on multiplying the compound "2014-2018 Growth Rate" for each category, by its percentage proportion of non-energy/non-gas cost revenue requirement category, offset by the annual growth in sales revenue to customers from the 2018 test year to the end of Rate Year 1 (March 31, 2021), resulting in the final electric and natural gas "Growth Rate %" of 4.14% and 6.11%, respectively (column (c) of Table Nos. 4 and 5).

Page 6 of Exhs. EMA-4 and EMA-5 shows the calculation of the non-power supply/non-gas cost growth in sales revenue to customers from the 2018 historical test year to March 31, 2021 (the end of Rate Year 1) and the annual revenue amount (total divided by 2.25 years) to be applied as an offset against the individual Growth Rate % categories. This growth in sales revenue produces an offset (reduces the overall Revenue Growth Rate) of 0.88% for electric and 1.34% for natural gas (shown in column (c) of Table Nos. 4 and 5).

Finally, as summarized on Page 1 of Exhs. EMA-4 and EMA-5 and recreated in Table Nos. 4 and 5, the calculation of the electric and natural gas Revenue Growth Rates, as described above, produces a Revenue Growth Rate of 4.14% for electric and 6.11% for natural gas.[55]

Q. Please further explain the efficiency adjustment applied to the Operating Expense growth category.

A. For the Operating Expense category, which includes O&M, customer service, and administrative and general expenses, Avista has included a 30 basis point (0.30%) "efficiency adjustment," reducing the Operating Expense growth percentage from 2.72% to 2.42%% for electric, and reduces the natural gas Operating Expense growth percentage from 4.29% to 3.99%.

Q. Is the derivation of the Revenue Growth Rates similar to the approach used by the Company in its prior GRC filed in 2017 (Docket Nos. UE-170485 and UG-170486), in support of a Three-Year Rate Plan?

A. Yes. The approach described above is consistent with that proposed in the Company's direct filed case in that proceeding for its proposed Three-Year Rate Plan.

Q. Did Staff witness Mr. Hancock use a similar approach in the prior case to determine a revenue increase for Rate Years 2 and 3 of their proposed Three-Year Rate Plan?

A. Yes. Similar to Avista, Mr. Hancock applied a revenue growth factor (escalation rate) to his base Year 1 revenue to determine Year 2. Year 2 revenues then become the base for determining Year 3.[56]

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[55] As noted previously, the Revenue Growth Rates are applied to non-energy and non-gas costs revenues. On a <u>billed basis</u> (including total revenues) these percentages reflect a proposed <u>3.35%</u> incremental revenue increase for <u>electric</u>, and <u>4.59%</u> incremental revenue increase for <u>natural gas</u> for Rate Year 2, effective April 1, 2021.
[56] Hancock, Exh. CSH-1T, p. 34, ll. 21-23.

Q. Were there similarities between Avista and Staff's revenue growth factors?

A. Yes. Both Avista and Staff calculated separate electric and natural gas revenue growth factor percentages, consolidated from the weighted average revenue escalation factors of the following components: (1) depreciation; (2) O&M expense; (3) Taxes Other Than Income; and (4) Net Plant After ADFIT). The result of these components were offset by a fifth component (5) Annual Growth in Sales Revenue.[57] How certain of the components, namely: (1) depreciation; (2) O&M expense; and (3) Taxes Other Than Income where computed, were computed differently between Avista and Staff in that proceeding, but both produced an overall consolidated escalation growth rate to be applied to revenues from the first year approved revenue requirement, excluding power and gas costs.

Q. In Avista's 2016 GRC (Docket UE-160228/UG-160229) what guidance did the Commission give regarding multi-year rate plans and use of escalations?

A. In Avista's 2016 rate case, the Commission stressed that any escalation over time must begin with development of a modified historical test year with pro-forma plant additions.[58] In addition they stated in Order 06 at ¶76:

> "A future proposal for <u>a multi-year rate plan</u> such as that approved for Avista in 2012, or for PSE in 2013, for example <u>could include both updated rates as a starting point and rate escalator one year later, or escalation annually for two or three years</u>, subject to reporting requirements, and, perhaps, an earnings test or sharing mechanism," (emphasis added)

Q. Furthermore, is the Company's proposed Two-Year Rate Plan and

[57] Staff's descriptions of its calculations was provided at Hancock Exh. CSH-1T, starting at p. 34, ll. 16.
[58] See Washington Utilities and Transportation Commission, Order 06, Dockets UE-160228 and UG-160229 (hereinafter the 2016 Order or Case), ¶62.

Revenue Growth Rate methodology to determine Year 2 revenues, a similar approach to that actually approved by the Commission for Puget Sound Energy in Dockets UE-121697/UG-12705 & UE-130137/UG-130138 *(consolidated)*?

A. Yes, with a few exceptions. First, Puget Sound Energy (PSE) used compound growth in costs from approved general rate case compliance filings for a period of years prior to their 2012 filed case. Avista used normalized Commission Basis data, as consistent data from approved general rate case compliance filings for a recent period are not available. The normalized CBR data provides consistent normalized Commission Basis results for the historical period.

Second, Avista has included "taxes other than income," as a separate component, as these expenses are mainly changes in property tax expense related to changes in the growth in plant additions over time. It is our understanding, that PSE was granted a "Property Tax Tracker" or mechanism in the same Docket (as referenced above) their growth factor ("K-Factor") and Multi-Year Plan were approved by the WUTC.

Lastly, PSE used O&M expenses based on the Consumer Price index (CPI) less a "productivity factor" or "efficiency adjustment." The Company, however, believes CPI is not an appropriate measure for considering growth in O&M and other expenses for a utility, as CPI does not track costs typically implicit in the operations of a utility. However, the Company has applied an "efficiency adjustment" to its Operating Expense Growth Rate component, consistent with PSE.

Furthermore, in PSE's case, the Commission indicated support for the use of trended data within the escalation factors (K-Factors) used by PSE, in Order 07, Dockets UE-

121697/UG-12705 & UE-130137/UG-130138 *consolidated*, paragraphs 149, 157 and 158, as follows:

> As in the Avista case, we determine that the trending analysis on which PSE bases the rate plan escalation factors supports their approval as an appropriate measure to address earnings attrition going forward. That is, PSE's analysis of actual historical trends in the growth rates of revenues, expenses, and rate base to estimate the erosion in rate of return caused by disparate growth in these categories that PSE will experience absent application of these escalation factors supports the adjustments. …PSE fairly represents what the data show. While various results can be read into these data, PSE's analyses are straightforward and easy to follow. … We determine that the escalation factors reasonably represent the levels of growth in non-production costs that PSE may expect over the term of the rate plan.

Avista agrees with these points, and has determined its Revenue Growth Rate components on appropriate data which supports the rate plan Revenue Growth Rate percentages in order to recognize earnings erosion during the Two-Year Rate Plan; it uses a methodology which is straightforward, easy to follow and reasonably represents the level of growth in costs expected over the term of the rate plan.

Q. In conclusion, how does the Company's Two-Year Rate Plan satisfy the Commission guidance referenced in the various dockets above?

A. The Company's Two-Year Rate Plan satisfies the Commission's guidance in previous orders as follows:

1) It starts with a pro formed historical test period;
2) It has an earnings test and sharing mechanism;
3) It provides an incentive for the Company to reduce costs, including a built-in "efficiency adjustment" for Rate Year 2 and the discipline resulting from only limited recovery of capital investment; and
4) It allows for a review of actual plant level balances prior to rates going into effect, to assure the level of plant included in rates is in-service prior to Rate Year 2.

VIII. PROPOSED RECOVERY OF COLSTRIP UNITS 3 AND 4 REFLECTING ACCELERATED DEPRECIATION TO 2027

Q. How is the Company addressing issues surrounding Colstrip depreciation that were set aside in Docket No. UE-180167, for later review in this general rate case?

A. In the Commission's March 25, 2019 Order 04 in the Avista Depreciation proceeding (Docket No. UE-180167), all Colstrip depreciation issues were to be determined in this general rate case. Among the issues to be addressed, are the appropriate end of useful life for depreciation purposes of Colstrip Units 3 and 4 and whether some or all of the remaining non-plant related Excess Deferred Federal Income Taxes (DFIT) of $10.9 million[59] under the new Federal Tax act should be used as a partial offset to any increased depreciation expense resulting from accelerating depreciation. In addition, the appropriate amortization period of the undepreciated balance of Colstrip investment was to be discussed.

Q. Please provide an overview of your proposal for recovery of Avista's investment in Colstrip.[60]

A. Avista is proposing the same solution that has been put forth in two previous dockets that were agreed to by the parties in those dockets. The solution was first proposed in settlement discussions in the Hydro One acquisition proceeding.[61] Due to the termination

[59] The estimated remaining Excess DFIT is revised from $10.9 million to $11.7 million to include accrued interest of approximately $0.8 million through March 31, 2020.
[60] 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.
[61] In the Matter of the Joint Application of Hydro One Limited (acting through its indirect subsidiary, Olympus Equity LLC) and Avista Corporation for an Order Authorizing Proposed Transaction, Docket No. U-170970.

of the Hydro One proposed acquisition of Avista, the solution was then revisited and agreed to by the parties in the depreciation study proceeding[62]. In the Depreciation proceeding (Docket No. UE-180167) as noted above, the Commission determined the Colstrip depreciation issues were to be determined in this general rate case, including the method to recover the $104.1 million of undepreciated costs of Colstrip. Therefore, the Company has included in this filing the same solution that was agreed to in the depreciation study proceeding, with updated amounts. In addition, the Company has included capital investment for 2018 and 2019, for prudency review and approval in this proceeding.

The Company has built into its revenue requirement the acceleration of depreciation on Colstrip Units 3 and 4 assuming a remaining "useful life" of those units through December 31, 2027.[63] The accelerated depreciation of Colstrip Units 3 and 4 and the recovery of the asset retirement obligations (ARO) of Colstrip (as approved by the Commission in Docket UE-180167) will cause rate pressure for customers without implementing the proposed solution described here. To further reduce the rate pressure on customers associated with these increased costs, the Company's proposal also makes use of the tax credits that were created with the Tax Cuts and Jobs Act (TCJA) of 2017.[64]

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[62] Docket No. UE-180167

[63] These units had been on a depreciation schedule of 2034 and 2036, respectively.

[64] The primary provision of the TCJA was a reduction in the federal corporate tax rate from 35% to 21%, reducing the current and deferred tax expense currently included in customers' rates. The TCJA also required accumulated DFIT balances as of December 2017 to be revalued at the lower corporate rate (21%). The difference between the original balance recorded at 35% and the new balance recorded at 21%, resulted in excess DFIT (EDIT). EDIT was categorized as "protected" and "unprotected." "Protected" EDIT is generally defined as capital assets (plant) depreciated under Internal Revenue Code (IRC) section 167, and these timing differences are required to be recorded and then reversed (i.e. normalized) over the depreciable lives of the capital assets that created the EDIT. "Unprotected" EDIT mainly represents non-plant related deferred assets/liabilities. The non-plant EDIT balances have no IRC requirement as to when they must be reversed.

The use of the tax credits has two results, which are described in detail below. First, the "temporary" tax credits offset the amount that will need to be collected from customers and therefore, reduces the amount of rate base on the effective date of this rate case. Second, by recovering the cost of Colstrip over the same time frame as the long-term plant tax credits, the customers' rates in the future will be more equitable.

The proposed recovery of these Colstrip costs includes the following:

- Maintain the current level of depreciation expense currently being recovered from customers through 2027, so there is no immediate impact of the acceleration of depreciation/ARO costs.[65]
- Use of certain tax benefits to offset the increased costs associated with the acceleration of depreciation/ARO costs on the current Colstrip Unit 3 and 4 assets.
- Use deferred accounting to accumulate Colstrip costs not recovered from customers through existing rates, to be amortized over approximately 34 years, through 2053.

Q. What depreciable life of Colstrip Units 3 and 4 had been established with Docket No. UE-180167?

A. The Parties in Docket No. UE-180167 had agreed to a depreciation schedule for Colstrip Units 3 and 4 that accelerates the remaining useful life of those units for depreciation purposes to December 31, 2027. This also coincides with the agreement reached in Puget Sound Energy's recent rate proceeding (Dockets UE-170033 and UG-170034 (*consolidated)*) to resolve the depreciable life for those assets.

Q. But hasn't recent legislation set 2025 as the end date by which the Company must remove coal from its Washington jurisdiction?

[65] Current customers' rates include depreciation expense on Colstrip Units 3 and 4 of approximately $4.533 million annually (Washington share), with assumed remaining useful lives of these units through December 31, 2034 and December 31, 2036, respectively. Annual depreciation expense is approximately $6.937 million on a system-basis.

A. Yes. The revenue requirement in this case was completed prior to the finalization of the “Clean” initiative, which is expected to be signed into law in early May 2019, requiring the removal of coal in Washington State by 2025. The Company will update its proposed impact of using an accelerated depreciation date of 2025 for its Colstrip assets in Washington during the process of this case. Based on preliminary estimates, the Company anticipates the increased Colstrip Regulatory Asset and amortization to reflect a 2025 depreciable life would require an additional increase in revenue requirement of approximately $236,000.

Q. As a part of Docket No. UE-180167, was there any agreement on the closure date of Colstrip Units 3 and 4?

A. No. The Parties acknowledged that there presently is no plan to close Colstrip Units 3 and 4 by a specific date, nor has Avista agreed to do so.

Q. What are the costs of Colstrip Units 3 and 4 included in this filing?

A. In Docket No. UE-180167, the Commission approved the remaining undepreciated balance (Washington share) for Colstrip Units 3 and 4 that were in service at December 31, 2017, including estimated asset retirement obligations, as of March 31, 2019 of approximately $104.1 million.[66] This includes the unrecovered plant balance of $65.7 million, as well as the estimated asset retirement obligations previously not included in rates of $38.3 million.[67] This unrecovered balance at March 31, 2019, will be lowered to $99.5 million, due to the collection of $4.553 million of current depreciation expense between

[66] All amounts included in this testimony represents Washington’s share, unless otherwise noted.
[67] The asset retirement obligations costs, as referred here, include decommissioning, remediation costs and interim cost of removal.

April 1, 2019 and March 31, 2020. In addition, the unrecovered balance was increased by $2.9 million for 2018 plant additions and $2.5 million for 2019 plant additions proposed for recovery in this case.[68] Table No. 6 below summarizes the total cost of Washington's current depreciable Colstrip Unit 3 and 4 balance of $105.0 million:

Table No. 6

Summary of Colstrip Costs (Washington Share) ($000s)	
Net Book Value of Colstrip Units 3 & 4, including transmission assets, in service at December 31, 2017, at March 31, 2019	$ 65,711
Estimated Asset Retirement Obligations	38,350
Undepreciated Balance at March 31, 2019	104,061
Depreciation Expense for April 1, 2019 through March 31, 2020 (current amount recovered in rates)	(4,533)
Undepreciated Balance on Colstrip assets in service at December 31, 2017, at March 31, 2020	99,528
Net Book Value of Colstrip Additions in 2018	2,944
Estimated Net Book Value of Colstrip Additions in 2019	2,528
Undepreciated Balance at March 31, 2020	**$ 105,000**

Q. With the acceleration of the depreciable lives of Colstrip Units 3 and 4, how does that impact customer depreciation expense?

A. The Commission in its Order 07 (¶35) agreed to keep the current depreciation rates on Colstrip property unchanged until the effective date of this general rate case filing. When new depreciation rates take effect, the Company is proposing to keep the current level

[68] Please see Company witness Mr. Thackston (Exh. No. JRT-1T) for description of plant additions in 2018 and 2019.

of depreciation expense <u>already included in existing customers' rates</u> for Colstrip Units 3 and 4, which yields an annual depreciation expense of approximately $4.533 million. This results in no increase in depreciation expense included in customers' rates associated with the acceleration of Colstrip's depreciable assets (and recovery of the current undepreciated balance of Colstrip Units 3 and 4).

Q. With depreciation expense in customers' rates remaining the same, how then will the current depreciable balance for Colstrip Units 3 and 4 be recovered?

A. Table No. 7 below summarizes the recovery of Washington's current depreciable Colstrip Unit 3 and 4 balance of $105.0 million:

<u>Table No. 7</u>

Summary of Proposed Recovery of Colstrip Costs (Washington Share) ($000s)	
Undepreciated Balance at March 31, 2020	**$ 105,000**
Future Depreciation Expense Recovered April 1, 2020 - December 31, 2027	(35,135)
Tax Reform Tax Credits[1]	(11,709)
Net Colstrip Costs Deferred as Regulatory Asset	$ 58,156
Amortization Period (Years)	33.75
Annual Amortization	**$ 1,723**

[1] If the Commission orders the use of the $11.7 million Tax Reform Tax Credits for other purposes, the annual amortization amount would be approximately $2.070 million versus $1.723 million.

Similar to the approach previously agreed to by the Parties in Docket UE-180167, as shown in Table No. 7 above, the Company proposes that the $105.0 million undepreciated Colstrip balance would be recovered as follows:

- $35.135 million through the annual depreciation expense of approximately $4.533 million. As noted above, this is the current level of annual depreciation expense until December 31, 2027;

- $11.709 million of "temporary" tax credits, described further below; and
- $58.156 million through the amortization of a Regulatory Asset (FERC Account No. 183.3)[69] over 33.75 years, resulting in approximately $1.723 million per year of amortization expense. As described further below, the amortization schedule of the Regulatory Asset over 33.75 years is structured to match the amortization schedule of protected Plant EDIT, so that the amortization of protected Plant EDIT coincides with the amortization of the remaining depreciable Colstrip balance.

Q. Please describe the "temporary" tax credits used to offset the Colstrip depreciable balance.

A. As shown in Table No. 7 above, the Company has proposed to offset the Colstrip Units 3 and 4 depreciable balance with "temporary" tax credits of approximately $11.7 million. The $11.7 million of tax credits proposed to offset the Colstrip costs are comprised of non-plant EDIT ("unprotected" EDIT), described previously, at December 31, 2017, totaling approximately $10.9 million electric on a revenue requirement basis plus approximately $0.8 million of interest estimated to be accrued through April 30, 2020.

Q. Please further explain the reasoning behind setting the amortization period of Colstrip deferred costs over the same period as the "Protected" plant EDIT.

A. Avista has an electric plant excess ADFIT balance (Regulatory Liability) of approximately $208.3 million. In accordance with the TCJA's Average Rate Assumption Method (ARAM), the Company is required to reverse (i.e. normalize) these balances over the depreciable lives of the capital assets that created the ADFIT.

[69] The Regulatory Asset, net of accumulated deferred federal income taxes, will be included in rate base and will earn Avista's rate of return. Total Colstrip accounts included as rate base associated with the plant and regulatory related assets/liabilities, include the following: FERC Account No. 101.0 – Plant Cost, FERC Account No. 108.0 – Accumulated Depreciation, FERC Account No. 182.3 – Regulatory Asset ARO, FERC Account No. 182.3 – Regulatory Asset Colstrip, FERC Account No. 230.0 – Colstrip ARO, and FERC Account No. 242.0 – Colstrip Accounts Payable.

The Company estimates the ARAM for Avista results in an amortization period of approximately 36 years from December 31, 2017 or a remaining 33.75 years from April 1, 2020. The amortization of this balance over 36 years provides a tax benefit to customers (reduction in rates) of approximately $5.7 million annually.[70] This long-term tax benefit was included with the base rate change ultimately approved by this Commission, effective May 1, 2018, in Avista's most recent GRC (Dockets UE-170485/UG-170486 and UE-171221/UG-171222 *consolidated*).

As it relates to the Colstrip Regulatory Asset, as noted in Table No. 7 above, the Company has proposed that the Colstrip Regulatory Asset of $58.2 million also be amortized over 33.75 years, resulting in an increased amortization expense of approximately $1.7 million annually. Using consistent amortization periods, the increase in amortization expense beginning with the effective date of this rate case, April 1, 2020 of $1.7 million, coincides with the amortization of protected plant EDIT of $5.7 million annually, over the remaining 33.75 year period.

Q. Why use the "temporary" tax benefit if $11.7 million to offset depreciation expense, instead of returning them immediately to customers?

A. Use of the $11.7 million "temporary" tax benefits, as well as amortizing the Colstrip costs over the same period as the long-term tax benefits, produces more equitable rates for customers by addressing the issue of <u>intergenerational equity</u>. This benefit of the

[70] The annual excess plant ADFIT amortization benefit will vary annually as the IRS ARAM is not calculated on a straight-line basis.

proposed recovery of Colstrip costs was explained by Staff witness Jing Liu in the depreciation study proceeding[71], as follows:

> **Q. How does this Settlement Agreement address issues of intergenerational equity?**
>
> A. As I mentioned earlier, two important factors in determining depreciation rates are expected useful life and net salvage value. For a long-lived asset such as a coal plant, as the plant is placed in service there is substantial uncertainty with respect to both factors. Incorrect assumptions for the useful life and the cost of removal, including assumptions on decommissioning costs and environmental remediation, in the early life can lead to a misallocation of costs across the various generations of ratepayers using the facility.
>
> If all parties had a crystal ball when these Colstrip units were put in service in the 1980s, and we had assumed then that the facility would close in 2027, the depreciation rates for those assets would have been set at a much higher level; accordingly, customer rates would have been set at a higher level to recover equitably allocated Colstrip-related depreciation expense. However, no party had this perfect foresight, nor could parties anticipate costly asset retirement obligations (AROs) due to the development of more stringent environmental regulations. As a result, the Colstrip plant balance is currently under-depreciated, meaning that ratepayers in the past paid less than their fair share of the cost of the asset. It is important to recognize that this intergenerational inequity has already been created, and under-recovered plant balances are not the “fault” of the ratepayers in coming decades. Nevertheless, we must now consider how to allocate the remaining undepreciated balance, while finding ways to minimize the rate impact to undeserving customers.
>
> As Staff Witness Mr. Hancock explained in his testimony in the proposed Hydro One acquisition proceeding, the Tax Cuts and Jobs Act of 2017 provided us with a unique opportunity to remedy the intergenerational inequity related to Colstrip.[72] The Act reduced the corporate tax rate from 35 percent to 21 percent, resulting in a large reserve of EDIT that the utilities must pass back to ratepayers. EDIT represents money overpaid by ratepayers in the past and that will be received by ratepayers in the future. Importantly, and conveniently for solving the Colstrip intergenerational inequity, the EDIT intergenerational inequity is in the opposite direction of the Colstrip intergenerational inequity; that is, ratepayers in the past substantially underpaid for Colstrip, but substantially overpaid taxes.
>
> In solving these two intergenerational inequity problems, the Settlement Agreement proposes to offset a portion of the undepreciated Colstrip balance with

[71] Dockets UE-180167 & UG-180168, Testimony of Jing Liu, Exh. JL-1T, at pp. 11-12.

[72] *In the Matter of the Joint Application of Hydro One Limited (acting through its indirect subsidiary, Olympus Equity LLC) and Avista Corporation for an Order Authorizing Proposed Transaction*, Docket U-170970, Testimony of Christopher S. Hancock (April 10, 2018), at 19-25.

EDIT. More specifically, (1) unprotected EDIT will be used to offset a portion of the Colstrip balance immediately, and (2) a newly created Colstrip Regulatory Asset will be amortized over the same time period where protected EDIT is amortized consistent with Internal Revenue Service rules. By addressing these issues simultaneously, the Settlement creatively solves the issue of intergenerational inequity.

Q. Please compare the impact to customers of using the "temporary" tax refund dollars of $11.7 million to offset the undepreciated Colstrip balance versus immediately returning those dollars to customers.

A. If this Commission were to require the immediate return of the $11.7 million "temporary" tax dollars to customers, rather than use as an offset against the undepreciated Colstrip balance of $105 million, the amount deferred for later recovery (over the proposed 33.75 years), would increase from $58.2 million (see Table No. 7 above) to $68.9 million. Amortizing this balance over the proposed 33.75 years would increase the amortization expense of the deferred Colstrip Regulatory Asset from $1.7 million (see table No. 7) to approximately $2.1 million annually.[73] Table No. 8 illustrates the change in the Colstrip Regulatory Asset and amortization expense.

<u>Table No. 8</u>

Summary of Proposed Recovery of Colstrip Costs (Washington Share) ($000s)	
Undepreciated Balance at March 31, 2020	**$ 105,000**
Future Depreciation Expense Recovered April 1, 2020 - December 31, 2027	(35,135)
~~Tax Reform Tax Credits~~	-
Net Colstrip Costs Deferred as Regulatory Asset	$ 69,865
Amortization Period (Years)	33.75
Annual Amortization	**$ 2,070**

[73] A return (using the Company's authorized rate of return) on the additional rate base balance (see table No. 8), which is reduced under the Company's proposed method (see Table No. 7), would also increase the annual impact to customers over the amortization period of the Colstrip Regulatory Asset.

Q. What is the impact on rate base of the Company's proposal?

A. Rate base for Colstrip in current customers' rates is $68.988 million, which represents the ending net book balance at December 31, 2016.[74] The Company has included $54.941 million in this filing. Table No. 9 details the activity between December 31, 2016 and March 31, 2020, resulting in the $54.941 million proposed rate base at the effective date of this filing.

Table No. 9

Summary of Impact to Rate Base for Colstrip Proposal (Washington Share) ($000s)	
Colstrip Rate Base in Customers' Rates - Net Book Value at December 31, 2016	$ 68,988
Colstrip Additions	
2017	7,052
2018	3,027
2019 (estimate)	2,586
Total Additions	12,665
Actual Colstrip Depreciation Expense	
2017	(4,533)
2018	(4,682)
2019	(4,660)
3 months ended March 31, 2020	(1,128)
Total Depreciation Expense	(15,003)
Tax Reform Tax Credit	(11,709)
Proposed Colstrip Rate Base at March 31, 2020	**$ 54,941**

As shown in Table No. 9, the immediate impact of the Company's proposal is to reduce rate base by the use of the temporary tax credit of $11.7 million.

[74] Net book value includes plant-in-service less accumulated depreciation. Accumulated deferred taxes have not been included in any of the rate base calculations described in this testimony.

The long-term impact of the Company's proposal to rate base is to extend it from Colstrip's original life of December 2034 and 2036 to December 2053 through amortization of the proposed Colstrip Regulatory Asset (over 33.75 years).

In addition, the Company's proposal includes the recovery of ARO costs that has not been previously addressed in customer rates. As described above, the Company has proposed to include the net costs of the ARO's in rate base (i.e. FERC Account No. 182.3 – Regulatory Asset ARO, FERC Account No. 182.3 – Regulatory Asset Colstrip, FERC Account No. 230.0 – Colstrip ARO, and FERC Account No. 242.0 – Colstrip Accounts Payable). By including the net costs, the only costs that actually increase rate base are those costs that have been paid for by the Company. Therefore, any cost that is accrued for generally accepted accounting rules do not increase rate base. As shown in Table No. 10 below, the ARO's at the completion of this rate case net to zero rate base.

Table No. 10

Summary of Colstrip ARO Costs at March 31, 2020 (Washington Share) ($000s)

FERC Account	Description	WA Amount
101/317	Colstrip ARO Asset	$ 9,069
108/317	Colstrip ARO Accumulated Depreciation	(755)
182376	Colstrip Regulatory Asset - ARO	2,840
230000	Colstrip ARO Liability	(11,153)
	Net ARO Balance	**$ -**

Q. Did Order 04 (Modified) in Docket No. UE-180167 impact recovery of future capital additions or additional asset retirement costs related to Colstrip Units 3 and 4 that occur beyond January 1, 2018?

A. No. Nothing in the order precludes Avista from seeking recovery of costs that occur beyond January 1, 2018, that result from additional future asset retirement costs, or from routine future capital maintenance costs incurred in the normal course of business, not intended to extend operational life, based on a showing of prudency in future general rate cases.

As noted above, the Company is requesting recovery in this proceeding related to 2018 and 2019 Colstrip capital additions. Capital additions for 2018 of $2.9 million (Washington share) are included in the Company's 2018 historical test year, whereas 2019 capital additions of $2.5 million (Washington share), have been pro formed into this case as described by Ms. Schuh. Mr. Thackston discusses the 2018 and 2019 Colstrip capital projects within his direct testimony.

Future Colstrip capital additions would be included in future GRC proceedings, and once reviewed and approved by this Commission, would be included in the deferred Colstrip Regulatory Asset and amortized over the then remaining amortization period through 2053.

IX. FASB AND FERC CHANGES IN ACCOUNTING

Q. Have there been any changes to accounting methods used by Avista since the last general rate case filing in Washington that may impact the rate year results?

A. Yes. There have been three areas that have experienced changed accounting methods. Two of the areas, including pension accounting and lease accounting, were changed due to updated accounting standards required by FASB (Financial Accounting Standards Board). The third area, accounting for AFUDC (Allowance for Funds Used

During Construction) was changed due to FERC (Federal Energy Regulatory Commission) requirements that were identified during a recent audit by FERC.

Q. Please describe the changes required by FASB and the impact to rate year results in this filing.

A. Neither of these updated accounting standards have resulted in a material change to rate year results.

ASU No. 2016-02 – Leases (Topic 842) was effective January 1, 2019. This standard requires most leases to be capitalized and shown on the balance sheet with corresponding lease assets and liabilities. For expense recognition, there will be a straight-line recognition of the minimum lease expense over the entire expected life of the lease, with a portion affecting the amortization of the asset and a portion to the liability, similar to interest. The Company has identified the Montana Riverbed Lease, the ground lease for Coyote Springs 2, and various telecomm site leases under the requirements of the new accounting standard. The Company will not include the recorded asset or liability in rate base and the Company does not expect the level of expense or classification of the expense to be materially different from the amount included in the test year. For leases entered into in the future, the Company will apply the new standard and will provide details of the new leases to the Commissions when those leases impact the next filed general rate case.

ASU No. 2017-07 – Compensation-Retirement Benefits (Topic 715) was effective January 1, 2018. This standard amends the income statement presentation of the components of the net periodic benefit cost for Avista's defined benefit pension and other post retirement plans. Under previous accounting, the net periodic benefit cost, which is comprised of current service-costs and other cost components, were all shown as pension expense or were capitalized to plant-in-service. Under the new standard, for financial statements prepared using generally accepted accounting principles, only the service-cost component is eligible for capitalization in plant-in-service and presented in the income statement as costs related to employees. The other costs components are required to be shown as a regulatory asset and outside of income from operations in the income statement. FERC did not require this accounting change, and therefore, Avista maintains its records using the FERC-approved method. Only Avista's consolidated financial statements are updated for the revised accounting with consolidating journal entries. Because Avista has used the FERC method in each of its state jurisdictions, this accounting was not adopted in the States, and therefore, the rate period results are consistent with prior cases.

Q. Please describe the change in accounting related to AFUDC that was required by FERC.

A. FERC notified Avista in December 2017 that they would be auditing the Company's compliance with Form 1 and 3-Q, and accounting requirements of the Uniform System of Accounts under CFR part 101. During the course of the audit (which is ongoing), FERC staff made recommendations regarding the recording of AFUDC and the tax treatment of the equity component of AFUDC. Neither of the recommended changes will result in changes to Avista's overall rate base. The new method of recording AFUDC and associated income taxes was recorded in 2018, which resulted in a decrease of deferred federal income taxes. This decrease is only a timing difference as deferred federal income taxes will be higher in future years. Avista deferred this tax benefit beginning in 2018, resulting in a Washington deferred balance of approximately $797,000 for electric and $235,000, and will continue to defer it until such time that the new method of calculating DFIT on equity AFUDC is built into rates, with the Commission's approval to do so.[75]

The Company filed an accounting petition on January 31, 2019 (Docket Nos. UE-190074 and UG-190075) requesting approval to record a regulatory asset in place of amounts recorded as plant-in-service.[76] In addition, the Company requested authorization to defer the excess deferred taxes collected (as noted above) and indicated it would work with Staff to return those funds to customers in a separate regulatory filing.

That said, the Company is not opposed to returning the electric and natural gas deferred balances, if approved by the Commission, for the period 2018 through March 31, 2020, as a two-year amortization included in this GRC as an adjustment to the Company's base rates requested in this case (Two-Year Rate Plan), or through a separate tariff returning these amounts over a period determined at a later time.

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

A. Yes, it does.

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[75] The Company estimates the total deferral for 2018 through March 31, 2020 to total approximately $2,036,000 for Washington electric and $505,000 for Washington natural gas.

[76] The Company also filed accounting applications in its Idaho (Case Nos. AVU-E-19-02/AVU-G-19-01) and Oregon (UM-1993) jurisdictions with similar requests. The Idaho Public Utilities Commission (IPUC) Staff filed comments on April 5, 2019, in support of the Company's application to record a regulatory asset in place of amounts recorded as plant-in-service, as well as its request to defer the excess deferred taxes collected for later to customers. No other party to the proceeding filed comments. An Order from the IPUC approving the Company's application is expected by the end of April 2019. The Public Utility Commission of Oregon has taken no action as of this time.