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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION	)	CASE NO. AVU-E-17-01
OF AVISTA CORPORATION FOR THE	)	CASE NO. AVU-G-17-01
AUTHORITY TO INCREASE ITS RATES	)	
AND CHARGES FOR ELECTRIC AND	)	
NATURAL GAS SERVICE TO ELECTRIC	)	DIRECT TESTIMONY
AND NATURAL GAS CUSTOMERS IN THE	)	OF
STATE OF IDAHO	)	ELIZABETH M. ANDREWS
	)	

FOR AVISTA CORPORATION

(ELECTRIC AND NATURAL GAS)

CONTENTS

I. INTRODUCTION

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

A. My name is Elizabeth M. Andrews. I am employed by Avista Corporation as 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.

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

Q. Would you briefly describe your responsibilities?

A. Yes. As Senior Manager of Revenue Requirements, I am responsible for the preparation of normalized revenue requirement and pro forma studies for the various jurisdictions in 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 Idaho, Washington and Oregon.

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

A. My testimony and exhibits in this proceeding will cover accounting and financial data in support of the Company's Two-Year Rate Plan for the period January 1, 2018 through December 31, 2019. I will explain pro formed operating results, including expense and rate base adjustments made to actual operating results and rate base. In addition, I incorporate the Idaho share of the proposed adjustments of other witnesses in this case.

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

A. Yes. I am sponsoring Exhibit No. 12, Schedule 1 (Electric) and Schedule 2 (Natural Gas), which were prepared under my direction. These exhibits consist of worksheets, which show actual twelve months ended December 31, 2016 operating results, pro forma, and proposed electric and natural gas operating results and rate base for the State of Idaho for rate years 2018 and 2019. The exhibits also show the calculation of the general revenue requirement, the derivation of the Company's overall proposed rate of return, the derivation of the net-operating-income-to-gross-revenue-conversion factor, and the specific pro forma adjustments proposed in this filing for 2018 and 2019.

II. COMBINED REVENUE REQUIREMENT SUMMARY – TWO-YEAR RATE PLAN: 2018 and 2019

Q. Please describe the Company's Two-Year Rate Plan proposed for the 2018 and 2019 rate years.

A. The Company is proposing a Two-Year Rate Plan for calendar years 2018 and 2019, with proposed increases effective January 1 of each year. The company is proposing a Two-Year Rate Plan to avoid annual rate cases in its Idaho jurisdiction, providing benefits to all stakeholders. A Two-Year Rate Plan, with increases in 2018 and 2019, would provide benefits to its customers by providing some level of rate certainty over this two-year period; relief to all stakeholders – customers, the Commission and its Staff, intervenors, and the Company - from the administrative burdens and costs of litigation of annual general rate cases; and to Avista by providing a two-year window to manage its business in order to achieve a fair rate of return within known price changes.[2]

Q. Please provide a summary of the 2018 and 2019 Two-Year Rate Plan results included in the Company's Idaho electric and natural gas operating pro forma studies.

A. 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 Idaho jurisdictional operations are 6.38% and 6.34%, respectively for rate year 2018. After taking into account additional incremental pro forma adjustments for the 2019 rate year, the pro forma electric and natural gas ROR are 5.66% and 5.46%, respectively. These return levels are well below the Company's requested rate of return of 7.81%.

Table No. 1 below provides a summary of the 2018 and 2019 Rates of Return per the pro forma studies versus that proposed by the Company.

[2] The Two-Year Rate Plan would not preclude tariff filings authorized by or contemplated by the terms of the Power Cost Adjustment (PCA), Purchased Gas Adjustment (PGA), Public Purpose Rider Adjustment (DSM) or similar adjustments. The Company is proposing that the Two-Year Rate Plan also not preclude the Company from filing for rate relief or accounting treatment for major changes in costs not reflected in this filing, such as the potential costs associated with participation in the Energy Imbalance Market, or new safety or reliability requirements imposed by regulatory agencies. Following a filing by the Company, all interested parties would have an opportunity to respond to the Company's filing and make recommendations to the Commission, with the Commission ultimately deciding the outcome of the filing.

Table No. 1

Two Year Rate Plan Rate of Return			
Service	2018 Pro Forma	2019 Pro Forma	Proposed
ID Electric	6.38%	5.66%	7.81%
ID Natural Gas	6.34%	5.46%	7.81%

The incremental revenue requirement necessary to provide the Company an opportunity to earn its requested ROR in rate year 2018 is $18,571,000 for its electric operations, and $3,480,000 for its natural gas operations. The overall 2018 base electric increase associated with this request is 7.53%. The 2018 base natural gas increase is 8.79% (5.68% on a billed basis).

The incremental revenue requirement necessary to give the Company an opportunity to earn its requested ROR in rate year 2019 is $9,936,000 (3.75%) for its electric operations, and $2,137,000 for its natural gas operations (4.96% base, and 3.25% on a billed basis).

Table No. 2 below provides a summary of the 2018 and 2019 requested revenue requirement and percentage increases.

Table No. 2

Two Year Rate Plan Revenue Requirement & Percentage Increases				
Service	**2018**		**2019**	
	Revenue	**Base %**	**Revenue**	**Base %**
ID Electric	**$ 18,571**	**7.53%**	**$ 9,936**	**3.75%**
ID Natural Gas	**$ 3,480**	**8.79%**	**$ 2,137**	**4.96%**
Natural Gas % increase on a billed basis:		*5.68%*		*3.25%*

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

A. The Company's last authorized rate of return for its Idaho electric operations was 7.58%, effective January 1, 2017, per Case No. AVU-E-16.03. The last authorized rate of return for its Idaho natural gas operations was 7.42%, effective January 1, 2016, per Case No. AVU-G-15-01.

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

A. The primary factor driving the Company's electric and natural gas revenue requirements in 2018 and 2019 is an increase in net plant investment (including return on investment, depreciation and taxes, and offset by the tax benefit of interest) from that currently authorized. For 2018, net power supply expenses contributes to the incremental revenue requirement. Reductions in usage compared to the current authorized level for two electric rate groups also had an impact on the Company's requested revenues.

Other changes impacting the Company's revenue requirement requests relate to slight net decreases in distribution, operation and maintenance (O&M), and administrative and general (A&G) expenses for both electric and natural gas operations, compared to current authorized levels.

Q. What are the major components of the increased net plant investment included in the Company's 2018 and 2019 electric and natural gas results?

A. Looking at the changes to "gross" plant in service for 2018, Idaho "gross" plant increases by approximately $73.9 million for electric, and approximately $33.0 million for natural gas, as compared to what is currently embedded in base retail rates. For 2019, "gross" plant increases by approximately $98.0 million for electric, and approximately $16.8 million for natural gas, as compared to 2018.

A breakdown of the incremental electric and natural gas gross plant additions for each year is as follows:

Gross Plant Additions (000s)		
	Electric	
Investment	2018	2019
Generation/Transmission	$ 23,600	$ 40,900
Distribution	$ 27,600	$ 27,400
General & Intangible	$ 22,700	$ 29,700
Total Electric Gross Additions	$ 73,900	$ 98,000
	Natural Gas	
Investment	2018	2019
Distribution	$ 22,700	$ 8,700
General & underground Storage	$ 10,300	$ 8,100
Total Natural Gas Gross Additions	$ 33,000	$ 16,800

The specific 2017 through 2019 pro forma capital expenditures undertaken by the Company to expand and replace its generation, transmission, distribution and general facilities are discussed further by Company witnesses Mr. Kinney 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.

Company witness 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.

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

A. Yes. As discussed in Company witness Mr. Johnson's testimony, the level of Idaho's share of power supply expense for 2018 has increased by approximately $1.9 million ($5.9 million on a system basis) from the level currently included in base rates. This increase in expense is primarily due to lower net spot market sales resulting from less favorable economic operating conditions for the Company's gas-fired resources.

In addition, as discussed by Company witness Mr. Schlect, 2018 pro forma transmission system <u>revenues decreased</u> $2.2 million, while system <u>expenses</u> <u>increased</u> $223,000, versus that currently included in base rates. This reduction in transmission revenues and increased expenses, increases Idaho's share of transmission net costs by $817,000.

Lastly, as discussed by Company witness Ms. Knox, loads included in the 2016 test year were lower than that authorized in the Company's last general rate case. That coupled with an expected reduction to one industrial customer's usage in 2017, led to a reduction of 2018 expected revenues of $2.9 Million. The reduction in usage was captured by Company witness Mr. Kalich to reflect the associated reduction in power supply costs of approximately $1.5 million, resulting in an overall net increase in electric revenue requirement of $1.5 million.

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

A. Certain expense items have changed since the 2016 rate year used in the last electric rate case (2015 for natural gas). Employee benefits such as wages have increased, offset, in part, by pension and post-retirement medical expense reductions. Also, as discussed by Mr. Kensok, IS/IT costs associated with software development, application licenses, maintenance fees, and technical support for a range of information services programs have increased from that in current base rates. He also explains that these increased IS/IT expenses are necessary to support Company cyber and general security, emergency operations readiness, electric and natural gas facilities and operations support, and customer services.

To recognize these cost changes, the Company has included a number of 2018 and 2019 pro forma adjustments to capture the net increases the Company will experience from the 2016 test year.

III. DERIVATION OF TWO-YEAR RATE PLAN REVENUE REQUIREMENT

Test Period for Ratemaking Purposes

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

A. The test period being used by the Company is the twelve-month period ending December 31, 2016, presented on a 2018 and 2019 pro forma basis. Currently authorized electric rates, effective January 1, 2017, were based upon the twelve-months ending December 31, 2015 test year utilized in case AVU-E-16-03, adjusted on a pro forma basis. Currently authorized natural gas rates, effective January 1, 2016, were based upon the twelve-months ending December 31, 2014 test year utilized in case AVU-G-15-01, adjusted on a pro forma basis.

Revenue Requirement – 2018 and 2019

Q. Would you please explain what is shown in Exhibit No. 12, Schedules 1 and 2?

A. Yes. Exhibit No. 12, Schedules 1 and 2, show actual and pro forma (2018 and 2019) electric and natural gas operating results and rate base for the test period for the State of Idaho.

Column (b) of page 1 of Exhibit No. 12, Schedules 1 and 2, show December 31, 2016 actual operating results and components of the average-of-monthly-average (AMA) rate base as recorded[3]; column (c) is the total of all adjustments to net operating income and rate base to reflect 2018 results; and column (d) is the 2018 pro forma results of operations, all under existing rates. Column (e) shows the revenue increase required which would allow the Company to earn a 7.81% rate of return for 2018. Column (f) reflects 2018 pro forma operating results with the requested increase of $18,571,000[4] for electric and $3,480,000 for natural gas.

Page 2 of Exhibit No. 12, Schedules 1 and 2, show similar columns starting with 2018 pro forma results (equal to column (d) on page 1 of Exhibit No. 12, Schedules 1 and 2), reflecting operating results and components of rate base for 2018 results, in column (b). Column (c), of page 2, is the total of all adjustments to net operating income and rate base to reflect 2019 results; and column (d) is the 2019 pro forma results of operations, all under existing rates. Column (e) and (f) shows the revenue increases required in 2018 and 2019 to allow the Company to earn a 7.81% rate of return for 2019. Column (g) reflects 2019 pro

[3] Actual plant rate base (cost, accumulated depreciation and associated DFIT) uses the 2016 AMA balances. Plant rate base is adjusted to a 2017 End-of-Period (EOP) for Rate Year 1 (2018), and 2019 AMA basis for Rate Year 2 (2019), with restating and pro forma adjustments.

[4] After completion of the Company's revenue requirement, we learned of the impact of a new aquatic invasive species fee, to be paid to the State of Montana, related to the Company's Noxon Rapids hydroelectric generating facility. Beginning on July 1, 2017, based on recently signed legislation, Avista will be required to pay this fee to the State of Montana. This fee will be imposed on a quarterly basis until June 30, 2019, at a rate of $795.76/MW of a "hydroelectric facility's" nameplate capacity. This fee is estimated to be approximately $1.6 million per year, or $0.6 million Idaho's share. The Company will update this information during the process of this case.

forma operating results with the requested increases of $9,936,000 for electric and $2,137,000 for natural gas, above that requested in 2018.

Q. Would you please explain page 3 of Exhibit No. 12, Schedules 1 and 2?

A. Yes. Page 3 of Exhibit No. 12, Schedule 1, shows the 2018 and 2019 revenue requirement calculations for electric of $18,571,000 and $9,936,000, respectively. Page 3 of Exhibit No. 12, Schedule 2, shows the 2018 and 2019 revenue requirement calculations for natural gas of $3,480,000 and $2,137,000, respectively.

Q. What does page 4 of Exhibit No. 12, Schedules 1 and 2 show?

A. Page 4 shows the proposed Cost of Capital and Capital Structure utilized by the Company in this case, and the weighted average cost of capital of 7.81%. Company witness Mr. Thies discusses the Company's proposed rate of return and the pro forma capital structure utilized in this case, while Company witness Mr. McKenzie provides additional testimony related to the appropriate return on equity for Avista.

Q. Would you now please explain page 5 of Exhibit No. 12, Schedules 1 and 2?

A. Yes. Page 5 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 Idaho State income taxes. Federal income taxes are reflected at 35%.

Q. Now turning to pages 6 through 11 for electric (Schedule 1), and pages 6 through 9 for natural gas (Schedule 2), of your Exhibit No. 12, please explain what those pages show?

A. Yes. Page 6 begins with actual operating results and rate base for the test period in column (1.00). Individual Commission Basis normalizing and restating adjustments that are standard components of general rate case filings begin in column (1.01) and continue through column (2.14) on page 8 for electric, and column (2.10) on page 7 for natural gas.

For electric, Exhibit No. 12, Schedule 1, individual pro forma adjustments for 2018 begin in column (3.01) on page 9 and go through column (3.10) on page 10, with the "2018 FINAL TOTAL" column on page 10 representing the total pro forma operating results and net rate base for the 2018 pro forma period. Page 11 of Exhibit No. 12, Schedule 1, includes all 2019 pro forma adjustment columns (19.01) through (19.05), with the "2019I FINAL TOTAL" and INCREMENTAL 2019 FINAL TOTAL" columns, representing the total pro forma operating results and net rate base for the

2019 pro forma period, and the incremental balances above the 2018 pro forma rate year.

For natural gas, at Exhibit No. 12, Schedule 2, individual pro forma adjustments for 2018 are listed on page 8, column (3.01) through column (3.08). Also on page 8, is the "2018 FINAL TOTAL" column representing the total pro forma operating results and net rate base for the 2018 pro forma period. Page 9 of Exhibit No. 12, Schedule 2, includes all 2019 pro forma adjustment columns (19.01) through (19.05), with the "2019 FINAL TOTAL" and "INCREMENTAL 2019I FINAL TOTAL" columns, representing the total pro forma operating results and net rate base for the 2019 pro forma period, and the incremental balances above the 2018 pro forma rate year.

IV. STANDARD COMMISSION BASIS AND RESTATING ADJUSTMENTS

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

A. The following adjustments are consistent with current regulatory principles and the manner in which they have been addressed in recent cases (i.e., AVU-E-16-03 and AVU-G-15-01), unless otherwise noted. Columns following the Results of Operations column (1.00) reflect restating adjustments necessary to: restate the actual results based on prior Commission orders; reflect appropriate annualized expenses and rate base; correct for errors; or remove prior period amounts reflected in the actual results of operations.

In addition to the explanation of adjustments provided herein, the Company has also provided workpapers, both in hard copy and electronic formats, outlining additional details related to each of the adjustments.

A summary of each adjustment follows:

Electric Adjustment (1.01) and Natural Gas Adjustment (1.01) - **Deferred FIT Rate Base**, adjusts the electric and natural gas Accumulated Deferred Federal Income Tax (ADFIT) balances. ADFIT reflects the deferred tax balances arising from timing differences between book recognition and tax recognition of certain income and deductions. The primary deductions that have timing differences, and therefore associated ADFIT, are Accelerated tax depreciation (Accelerated Cost Recovery System, or ACRS, and Modified Accelerated Cost Recovery, or MACRS) and bond refinancing premiums.

The effect of these adjustments on Idaho rate base is a reduction of $806,000 electric, and a reduction of $325,000 natural gas. The effect on Idaho net operating income (NOI) due to the Federal Income Tax (FIT) expense on the restated level of interest on the change in rate base[5] is a reduction of $8,000 electric and a reduction of $3,000 natural gas.

Electric Adjustment (1.02) and Natural Gas Adjustment (1.02) - **Deferred Debits and Credits**, is a consolidation of previous Commission Basis or other restating rate base adjustments and their NOI impact. The net impact on a consolidated basis of this adjustment decreases Idaho electric rate base by $84,000 and increases NOI by $29,000. No adjustment is necessary for natural gas rate base, net income however, increases by $1,000.

Adjustments included in the Deferred Debits and Credits consolidated adjustment are those necessary to reflect restatements from 2016 actual results (included in column 1.00 "Per Results of Operations"), based on prior Commission orders as explained below.

- **Colstrip 3 AFUDC Elimination (electric)** is a reallocation of rate base and depreciation expense between jurisdictions. In Cause Nos. U-81-15 and U-82-10, the Washington Utilities and Transportation Commission (WUTC) allowed the Company a return on a portion of Colstrip Unit 3 construction work in progress (CWIP). A much smaller amount of Colstrip Unit 3 CWIP was allowed in rate base in Case No. U-1008-144 by the Idaho Public Utility 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. These amounts are a component of actual results of operations.

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

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

- **Kettle Falls & Boulder Park Disallowances (electric)** reflects the Kettle Falls generating plant disallowance ordered by this Commission in Case No. U-1008-185 and the Boulder Park plant disallowance ordered by the IPUC in Case No. AVU-E-04-1. The IPUC disallowed the rate of return on the investment in Kettle Falls totaling $3,009,445. The Company is allowed to recover the depreciation expense (return of) of this investment. The IPUC also disallowed $2,600,000 million of investment in Boulder Park. The disallowed investment, and related accumulated depreciation and accumulated deferred taxes for both these disallowances are removed.

- **Restating CDA Settlement Deferral (electric)** adjusts the net assets and DFIT balances associated with the 2008/2009 past storage and §10(e) charges deferred for future recovery as recorded to a 2018 AMA basis, and records the annual amortization expense based on a ten-year amortization, as approved in Case No. AVU-E-10-01.

- **Restating Spokane River Deferral (electric)** adjusts the net asset and DFIT balances related to the Spokane River deferred relicensing costs as recorded to a 2018 AMA basis, and records the annual amortization expense based on a ten-year amortization as approved in Case No. AVU-E-10-01.

- **<u>Restating Spokane River PM&E Deferral (electric)</u>** adjusts the net asset and DFIT balances related to the Spokane River deferred PM&E costs as recorded to a 2018 AMA basis, and records the annual amortization expense based on a ten-year amortization as approved in Case No. AVU-E-10-01.

- **<u>Restating Montana Riverbed Lease (electric)</u>** 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 Case No. AVU-E-07-10. In Case No. AVU-E-08-01 (see Order No. 30647), the Commission approved the Company's accounting treatment of the deferred payments, including accrued interest, to be amortized over the remaining eight years of the agreement starting October 1, 2008. The eight-year amortization of the deferral expired September 2016, and has been properly reflected in this filing. Therefore, the rate base balance has been adjusted to reflect $0 for the 2018 rate year. This adjustment also includes the adjustment to annual lease payment expense for the required annual inflation adjustment.

- **<u>Weatherization and DSM Investment (electric)</u>** includes in rate base the Sandpoint weatherization balance remaining in FERC account 124.350 of $59,355. This balance will remain unchanged until property owners sell the property; Avista would then recover these DSM payments.

- **<u>Customer Advances (electric and natural gas)</u>** decreases rate base for moneys advanced by customers for line extensions, as they will be recorded as contributions in aid of construction at some future time.

- **<u>Amortization of Lake Spokane Deferral</u>** includes the amortization expense in 2018 to reflect the three-year amortization of the deferred costs related to improving dissolved oxygen levels in Lake Spokane. In Case No.

AVU-E-13-05 (see Order No. 32917), the Company received approval of an Accounting Order to defer the costs related to the improvement of dissolved oxygen levels in Lake Spokane. Order No. 32917 authorized the Company to defer and transfer Idaho's share of these costs (approximately $473,000) to FERC account 182.3 (Other Regulatory Assets) for later recovery, with no carrying charge. A four-year amortization of the deferral balance beginning January 1, 2016 through December 31, 2019 was approved in Case No. AVU-E-15-05.

- **Amortization of Colstrip Deferral** reflects the two-year amortization of the deferred revenues received from insurance proceeds related to the Colstrip lawsuit settlement funds received in 2014. The two-year amortization schedule is consistent with expenses associated with the Colstrip lawsuit settlement payments made in 2008 previously deferred and amortized over two-years in Idaho's jurisdiction. The two-year amortization of the deferral balance beginning January 1, 2016 through December 31, 2017 was approved in Case No. AVU-E-15-05.[6]

- **Amortization of Project Compass Deferral** includes the 2018 amortization expense associated with the four-year amortization of 80% of the deferred electric revenue requirement amounts associated with the Company's Project Compass Customer Information System (Project Compass) for calendar year 2015. In Case No. AVU-E-14-05, the Commission approved an all-party settlement, in which the Parties agreed that eighty-percent (80%) of the revenue requirement associated with Project Compass during 2015, beginning the month the Project goes into service, would be deferred, without a carrying charge, for recovery in a future proceeding. This project was moved into service on February 2, 2015. A four-year amortization of the deferral balance beginning January 1, 2016 through December 31, 2019 was approved in Case No. AVU-E-15-05.

[6] After completion of the Company's revenue requirement for electric, the Company realized it inadvertently had failed to remove the expiration of the Colstrip refund amortization during the 2018 rate year. This amortization will expire on December 31, 2017 reducing deferred revenues by $200,000, increasing revenue requirement $210,000.

Electric Adjustment (1.03) and Natural Gas Adjustment (1.03) - **Restate Capital 2016 EOP**, restates the capital investment and expenses associated with adjusting the 2016 average-of-monthly-average (AMA) plant related balances to December 31, 2016 end-of-period (EOP) balances. The effect on Idaho rate base is an increase of $28,127,000 for electric and $2,220,000 for natural gas. The effect on Idaho net operating income (NOI) is an increase of $282,000 electric and $22,000 natural gas related to the federal income tax effect of debt interest.

Electric Adjustment (1.04) and Natural Gas Adjustment (1.04) - **Working Capital**, restates the working capital balance reflected in the Company's Results of Operations column (1.00), to the adjusted working capital balance. The Company uses the Investor Supplied Working Capital (ISWC) methodology to calculate the amount of working capital reflected in its actual results of operations. This method is consistent with that incorporated in the Company's last approved electric general rate case, Case No. AVU-E-16-03. In addition, ISWC was revised to properly reflect the effect of Investment Tax Credit (ITC) in 2016 on the Company's Nine Mile capital project, which went into service in mid-2016. The net effect of adjustments to ISWC from that recorded per results of operations at December 31, 2016, decreases electric net rate base by $667,000, while increasing natural gas net rate base $447,000. This adjustment also decreases electric NOI by $7,000 and increases natural gas NOI by $4,000, due to the impact of debt interest.

Electric Adjustment (2.01) and Natural Gas Adjustment (2.01) - **Eliminate B & O Taxes**, eliminates the revenues and expenses associated with local business and occupation (B & O) taxes, which the Company passes through to its Idaho customers. The effect of this adjustment decreases electric NOI by $12,000 and natural gas NOI by $3,000.

Electric Adjustment (2.02) and Natural Gas Adjustment (2.02) - **Uncollectible Expense**, restates the accrued expense to the actual level of net write-offs for the test period. The effect of this adjustment increases electric NOI by $108,000 and natural gas NOI by $306,000.

Electric Adjustment (2.03) and Natural Gas Adjustment (2.03) - **Regulatory Expense**, restates recorded test period regulatory expense to reflect the IPUC assessment rates applied to expected revenues for the test period and the actual levels of FERC fees paid during the test period. The effect of this adjustment decreases electric NOI by $53,000 and natural gas NOI by $15,000.

Electric Adjustment (2.04) and Natural Gas Adjustment (2.04) - **Injuries and Damages**, is a restating adjustment that replaces the accrual with the six-year rolling average of actual injuries and damages payments not covered by insurance. This methodology was accepted by the Idaho Commission in Case No. WWP-E-98-11, and has been used since that time. The effect of this adjustment increases electric NOI by $15,000 and decreases natural gas NOI by $77,000.

Electric Adjustment (2.05) **FIT/DFIT/ITC/PTC Expense**, and Natural Gas Adjustment (2.05) **FIT/DFIT Expense**, adjusts the FIT and DFIT expenses calculated at 35% within Results of Operations, as needed, by reflecting the appropriate Schedule M items and jurisdictional allocation of these Schedule M items as compared to Results of Operations. In addition, for electric this adjustment records the appropriate level of production tax credits and investment tax credits on qualified electric generation. The net tax credit adjustment decreases Idaho electric NOI by $58,000. For the natural gas adjustment, no adjustment is required.

Electric Adjustment (2.06) and Natural Gas Adjustment (2.06) - **SIT/SITC Expense**, adjusts Idaho State Income Tax (SIT) expense and Idaho State Investment Tax Credits (SITC) applicable to Idaho electric and natural gas operations as recorded. This approach is consistent with that approved in Case No. UE-15-05. The effect on Idaho NOI is a decrease of $85,000 for electric and $31,000 for natural gas.

Electric Adjustment (2.07) and Natural Gas Adjustment (2.07) - **Revenue Normalization**, is an adjustment taking into account known and measurable changes that include 1) revenue normalization which reprices customer usage using the current authorized base rates, 2) weather normalization, and 3) an unbilled revenue calculation. For the electric adjustment, schedules, such as, Schedule 91 Tariff Rider, Schedule 95 Optional Renewable Power and Schedule 59 Residential Exchange, are excluded from pro forma revenues, and the related amortization expense is eliminated as well. For the natural gas adjustment, all revenues and expenses associated with the Purchased Gas Cost Adjustment Schedule 150 have been removed from the Company's filing. In addition, revenues associated with the temporary Gas Rate Adjustment Schedule 155, Schedule 191 Tariff Rider, and Schedule 197 Refund of Deferred Gas Costs are excluded from pro forma revenues, and the related amortization expenses are eliminated as well. Company witnesses Ms. Knox (electric) and Mr. Miller (natural gas) sponsor these two adjustments.

The effect of this adjustment increases electric NOI $1,208,000 and natural gas NOI $293,000.

Electric Adjustment (2.08) and Natural Gas Adjustment (2.08) - **Miscellaneous Restating** removes a number of non-operating or non-utility expenses associated with advertising, dues and donations, etc., included in error, and removes or restates other expenses incorrectly charged between service and or jurisdiction. The net effect of this adjustment increases electric NOI by $6,000 and natural gas NOI by $1,000.

Electric Adjustment (2.09) and Natural Gas Adjustment (2.09) - **Restate Incentives**, adjusts incentive compensation for non-executive employees and executive officers. The net effect of this adjustment (including both executive and non-executive) increases NOI by approximately $148,000 for electric and $39,000 for natural gas.

For non-executive employees, the first portion of the adjustment restates actual O&M incentive compensation expense recorded in 2016 to reflect a six-year average (2011-2016) of target payout.[7] The six-year average of incentive compensation payout is 109% for O&M metrics designed to drive cost-control, and delivery of safe, reliable service with a high level of customer satisfaction. The second portion of the adjustment, pro forms increases in variable pay/incentive compensation expense, from the year ending 2016 to the rate year amounts in effect, by approximately 3.0% per year, consistent with base pay increases in adjustment (3.03) Electric Pro Forma Labor Non-Exec and (3.01) Natural Gas Pro Forma Non-Exec.

For executive officers, the six-year average payout of O&M metrics related to efficiencies in cost management (O&M cost-per-customer), customer service and reliability have

[7] Target payout is based on salary in effect as of December 31, 2016.

averaged approximately 106%. The six-year average is applied to actual base compensation paid during 2016. Incentive compensation related to earnings-per-share and share-price financial metrics are excluded from the Company's filing with expenses borne by shareholders.

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

A. In accordance with the Company's overall compensation design to align elements of incentive plans among all Company employees including executives, the Non-Executive Employee STIP plan has essentially the same stated goals as the Short-Term Incentive Plan for executives (Executive STIP). Both plans provide incentives and focus employees on stated goals while recognizing and rewarding employees for their contributions toward achieving those goals. The components of the Non-Executive Employee STIP are all operational in nature, including cost containment on a per customer basis. The weighting of each component is as follows: 60% O & M Cost-Per-Customer, 15% Customer Satisfaction, 15% Reliability Index and 10% Response Time.[8]

This pay-at-risk component of compensation is part of the overall compensation for employees that is designed to

[8] Effective January 1, 2017, the weighting of each component has changed as follows: 50% O & M Cost-Per-Customer, 20% Customer Satisfaction, 20% Reliability Index and 10% Response Time.

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

Q. Please briefly describe the Executive STIP.

A. The Executive STIP is designed to align the interests of executives with both customer and shareholder interests in order to achieve overall positive operating and financial performance for the Company. The Executive STIP has four operational components, plus two earnings per share (EPS) components. The total amount associated with utility operational components is 40% and is broken down as follows: 20% O&M Cost-Per-Customer, 8% Customer Satisfaction, 8% Reliability, and 4% Response Time. The EPS components account for 60% of the total opportunity and are broken out into 50% utility EPS and 10% non-utility EPS. <u>Only the operational components (40%) are proposed to be included in retail rates.</u> Customers benefit from these metrics that are designed to drive cost-control, and delivery of safe, reliable service with a high level of customer satisfaction. The remaining 60% related to EPS targets is borne by shareholders.

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

A. The Company has included 100% of the Non-Executive

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

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

A. The Long Term Incentive Plan (LTIP) is comprised of two components, which serve two different purposes.[9] Performance Shares account for 75% of the plan with metrics related to Cumulative Earnings-Per-Share (CEPS) and Total

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

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

Restricted Stock Unit (RSU) awards account for 25% of the LTIP and vesting is based on a continuation of service by the employee. The purpose for this portion of the plan is to provide an incentive for employees to remain with the Company. The long-term nature of large-scale utility projects spanning multiple years are completed more efficiently with experienced, consistent leadership. In addition, it is the Company's policy to promote from within when possible, preserving the values inherent in our culture that drive customer satisfaction, reliability of service, etc. Employees with a long tenure of employment with the Company are well versed in the Company's culture and tend to continue to cultivate the values embedded within Avista. The Company has included approximately $304,000 electric expense and $80,000 natural gas expense in this filing.

Q. Please continue explaining the remaining restating adjustments in Exhibit 13, Schedules 1 and 2.

A. The next adjustment is Electric Adjustment (2.10) - **Idaho PCA**, which removes the effects of the financial accounting for the Power Cost Adjustment (PCA). Under the PCA certain differences in actual power supply costs, compared to those included in base retail rates are deferred and then surcharged or rebated to customers in a future period. Revenue adjustments due to the PCA and the power cost deferrals affect actual results of operations and need to be eliminated to produce normalized results. Actual revenues and power supply costs are normalized in adjustments (2.07) Revenue Normalization and (3.01) Power Supply, respectively. The effect of this adjustment increases Idaho NOI by $2,107,000.

Electric Adjustment (2.11) - **Nez Perce Settlement Adjustment**, reflects a decrease in production operating expenses. An agreement was entered into between the Company and the Nez Perce Tribe to settle certain issues regarding earlier owned and operated hydroelectric generating facilities of the Company. This adjustment directly assigns the Nez Perce Settlement expenses to the 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. The effect of this adjustment increases Idaho NOI by $22,000.

(2.12) – **Colstrip/CS2 Maintenance.** As approved in Order 32371 on September 30, 2011, (in Case Nos. AVU-E-11-01 and AVU-G-11-01), the Company deferred the non-fuel O&M costs associated with the Company's Colstrip and CS2 thermal generating plants. The deferral amount is the difference between actual costs in excess of authorized "Base O&M" costs for each respective year, included in base rates for the years 2011 – 2016 and estimated for 2017.

For calendar years 2013 through 2015, the authorized "Base O&M" expense level (established in 2013 in AVU-E-12-08) was $14.4 million. For 2016, in Case No. AVU-E-15-05, the system "Base O&M" cost was adjusted upward from $14.4 million to $20.4 million, to better reflect O&M expenses in the future based on a five-year average for the period 2012-2016, and will remain this amount going forward unless adjusted. Each prior year deferred costs are amortized over a three-year period.

Adjusting expense to one-third of each amount deferred for calendar years 2015 through 2017, decreases Idaho electric expense by approximately $209,000, and increases NOI by $129,000.

Electric Adjustment (2.13) – **2015 Storm 3-Year Amortization**, includes for regulatory purposes, the three-year amortization expense (2017-2019) of the customer portion of 2015 storm costs. The annual level of expense to amortize over the three-year period of $209,000 was determined in Case No. AVU-E-16-03. The net impact to electric NOI is a reduction of $130,000.

Electric Adjustment (2.14) and Natural Gas Adjustment (2.10) - **Restate Debt Interest**, restates debt interest using the Company’s pro forma weighted average cost of debt on the Results of Operations level of rate base shown in column (1.00) only. The weighted average cost of debt is as provided in the testimony and exhibits of Mr. Thies. This adjustment results in a revised level of tax deductible interest expense on actual test period rate base. The Federal income tax effect of the restated level of interest for the test period increases electric NOI by $412,000 and natural gas NOI by $77,000.

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

Finally, the "Restated Total" column on page 8 of Exhibit No. 12 Schedule 1, and page 7 of Schedule 2, represents the results of the previous adjustments columns (1.01) through (2.14) Schedule 1 and (1.01) through (2.10) Schedule 2.

V. 2018 AND 2019 PRO FORMA ADJUSTMENTS

Q. Please explain the significance of the adjustments beginning at page 9 for Schedule 1 (electric) and page 8 for Schedule 2 (natural gas) of Exhibit No. 12.

A. The adjustments on pages 9 and 10 of Exhibit No. 12, Schedule 1, and page 9 of Exhibit No. 12, Schedule 2 are pro forma adjustments that will impact the 2018 pro forma operating period.

Included on page 11, Schedule 1 and page 9, Schedule 2 of Exhibit No. 12, are additional pro forma adjustments that will impact the 2019 pro forma operating period.

These pro forma adjustments in 2018 and 2019 encompass revenue and expense items as well as additional capital projects, bringing the operating results and rate base to the final pro forma levels for the 2018 and 2019 rate years.

In the discussion that follows, an explanation of each 2018 and 2019 pro forma adjustment is provided. The Company has also provided workpapers, both in hard copy and electronic formats, outlining additional details related to each of the adjustments. As described below and provided in accompanying workpapers, these adjustments are consistent with current regulatory principles and the treatment reflected in the last rate case, with a few proposed changes by the Company discussed below.

2018 Rate Year – Summary of Adjustments

Q. Please explain each of the 2018 Pro Forma adjustments included in Exhibit No. 12, starting on page 9 of Schedule 1 and page 8 of Schedule 2.

A. The first adjustment, starting on Exhibit No. 12, page 9, of Schedule 1 is Electric Adjustment (3.01) - **Pro Forma Power Supply.** This adjustment was made under the direction of Mr. Johnson and is explained in detail his testimony. This adjustment includes pro forma power supply related revenue and expenses to reflect the twelve-month period January 1, 2018 through December 31, 2018, using weather normalized historical loads[10]. Mr. Johnson's testimony outlines the system level of pro forma power supply revenues and expenses that are included in this adjustment. The adjustment in column (3.01) calculates the Idaho jurisdictional share of those figures. The net effect

[10] The historical loads also include a pro forma adjustment as explained by Mr. Kalich and Ms. Knox.

of this adjustment decreases electric NOI by $5,736,000.

Electric Adjustment (3.02) - **Pro Forma Transmission Revenue/Expense**, was made under the direction of Mr. Schlect and is explained in detail in his testimony. This adjustment includes pro forma transmission-related revenues and expenses to reflect the twelve-month period January 1, 2018 through December 31, 2018. The net effect of this adjustment decreases electric NOI by $504,000.

Q. The next four electric adjustments (3.03) through (3.05) and natural gas adjustments (3.01) through (3.03) relate to pro forma labor and benefit adjustments. Prior to addressing each of the adjustments, please provide an overview of the Company's total compensation philosophy.

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

- Clearly identify the specific measures of Company performance that are likely to create long-term value for the Company's customers and shareholders;

- Keep employees focused on cost control, customer satisfaction, reliability and operational efficiencies by providing 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 explain electric adjustment (3.03) Pro Forma Labor Non-Exec and natural gas adjustment (3.01) Pro Forma Labor Non-Exec.

A. **Pro Forma Labor Non-Exec**, adjustment (3.03) electric and (3.01) natural gas, reflects changes to test period union and non-union wages and salaries, excluding executive salaries, which are handled separately in adjustments (3.04) electric and (3.02) natural gas. For <u>non-union</u> employees, the 3% increase for March 2017 represents actual increases already in effect. In May 2017, the Board of Directors voted to approve a minimum level of salary increases of 3% for March 2018[11]. Union employee increases are made in accordance with contract terms. The current contract with the IBEW Union 77 (Washington/Idaho) expires on March 25, 2019. The net effect of this non-executive labor adjustment decreases NOI by $728,000 for electric operations and $202,000 for natural gas operations.

Base pay, together with pay-at-risk/incentive compensation described in adjustment (2.09) above is designed to provide competitive compensation in the market place. As indicated earlier, this pay-at-risk component of compensation is part of the overall compensation for employees that is designed to be comparable with that of other similar utilities. If this pay-at-risk compensation were to be reduced or eliminated then base pay would need to be increased in order for overall compensation to remain competitive.

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 the market. Avista participates in numerous confidential salary surveys provided by third-party consulting firms which compare Avista's pay programs and

[11] A minimum increase of 3.0% for 2018 was approved by the Compensation Committee of the Board of Directors at the May 2017 quarterly Board meeting. The actual increase will be updated at or above this minimum based on market data provided in November 2017, for an effective date in March 2018.

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.

Electric adjustment (3.04) and natural gas adjustment (3.02) **Pro Forma Labor-Executive**, annualizes actual salary levels effective as of March 1, 2017. Base pay is allocated approximately 90% to utility operations and 10% to non-utility operations based on actual timesheet allocations as of December 31, 2016. This results in an increase in NOI for electric of $9,000 and natural gas of $2,000.

As with all components of executive officer compensation, the Compensation Committee of the Board of Directors (Board) determines the appropriate level of base salary. 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 utilizes 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 can reasonably be assumed to be the companies with which we compete for talent.

Electric adjustment (3.05) and natural gas adjustment (3.03) **Pro Forma Employee Benefits,** adjusts the year ending December 31, 2016 pension and medical expense to include the net changes in the Company's 401(k) and medical insurance expense expected during the rate year. In total, this adjustment reflects the change in total employee benefit expense on a system level from $40.5 million to $39.8 million (O&M). The total net effect of this adjustment is an increase to NOI of $109,000 for electric and $30,000 for natural gas.

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. Each component is carefully evaluated in order to ensure the appropriate level of overall benefits within the overall compensation package. To aid in benchmarking our benefit plan, 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. The table below illustrates the breakdown of components within this adjustment:

Adjustment (Expense)	System	O&M	Idaho Electric	Idaho Gas
Retirement	$ (2,849,327)	$ (1,640,642)	$ (380,629)	$ (104,509)
Medical	$ 1,530,803	$ 881,436	$ 204,493	$ 56,148
	$ (1,318,524)	$ (759,206)	$ (176,136)	$ (48,361)

Q. Please describe the Retirement Portion of the Employee Benefit adjustment.

A. As illustrated in the table above, the change in pension expense from the year ending December 31, 2016 to that expected during the rate year is a reduction of approximately $1.6 million (O&M) system ($381,000 Idaho Electric and $105,000 Idaho Natural Gas). Pension expense is determined by an independent actuary in accordance with Accounting Standard Codification 715 (ASC-715). The primary contributor to this reduction in expense is related to expected return on assets and the discount rate.

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. We anticipate updates for 2018 to be available sometime in the third or fourth quarter of 2017, and the Company will adjust pension expense at that time.

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

A. Effective January 1, 2014, the defined benefit pension plan is closed to all non-union employees hired or rehired on or after January 1, 2014.[12] 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

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

each employee's pay based on his or her age. 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. This reduces the future costs and risks to the Company of funding and managing the annual pension benefit (annuity) for retirees.

Q. Please now describe the role employee medical benefits play within the Company’s overall employee compensation.

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. The various components within the medical plan (co-pays, deductibles, premium sharing, etc.) are carefully evaluated in order to maintain an appropriate level of medical benefits within the benefit plan and ultimately overall employee compensation. The Company’s medical adjustment encompasses health insurance expense for active employees as well as post-retirement medical (FAS 106) for retired employees within the plan. The total medical expense portion of this adjustment of $881,000 (O&M) system ($205,000 Idaho Electric and $56,000 Idaho Natural Gas) adjusts for the estimated medical-related costs expected during the rate year, over and above the year ending December 31, 2016.

Q. Please provide an overview of how medical premiums for the Company are set.

A. Medical premiums[13] for the Company are set annually by an independent consultant, Mercer.[14] Premiums are estimated 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 to treat patients from one year to the next. Costs are generally related to the type of medical services, such as outpatient procedures, office visits, physical therapy and emergency room visits, prescription drugs, and medical equipment, among other things. The premium estimate is the basis for the medical cost estimate provided by Mercer. Mercer takes into consideration Company population profile (number and composition of participating employees), estimated medical and prescription costs, and laws/regulations in order to determine the appropriate

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

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

premium.

Q. What measures has the Company implemented to keep medical costs down?

A. Avista encourages employees to take responsibility for their health care by offering various wellness programs, biometric screening, health risk assessment tools, discounted gym memberships and on-site exercise classes and facilities.

To keep office visit costs down, we offer access to phone or web-based 24/7 telemedicine services and an on-site clinic. We have limited our exposure to large claims through an insurance policy with annual stop-loss limits of $250,000 per person. When employees do require medical care for catastrophic conditions, we have a case management program managed by a third-party administrator to help manage these costs. To keep prescription drug costs down, the Company has contracted with specialty pharmacies who help participants determine the most economic treatment options. In addition, the Company has made the following changes to the medical plan offered to employees:

- For non-union employees hired or rehired on or after January 1, 2014, and Local Union 659 employees hired or rehired on or after April 1, 2014, upon retirement the Company no longer provides a contribution towards his or her medical premiums. The Company will provide access to the retiree medical plan, but the retiree will pay the full cost of premiums upon retirement.

- Manage Utilization of Specialty Drugs – The Company reviews measures to lower the cost of prescription drugs including requiring prior authorization, and implementing step therapy.

- Beginning January 1, 2020, the method for calculating health insurance premiums for the following employee groups will change: non-union retirees, Local Union 659, hired or rehired after April 1, 2014 under age 65, and active non-union employees hired or rehired after April 1, 2014 under age 65. Revisions will result in separate health insurance premium calculations for retirees and active employees beginning January 1, 2020.

Q. What steps is Avista taking going forward to mitigate cost increases?

A. Beginning in 2017, Avista offered a self-insured High Deductible Health Plan ("HDHP") in addition to the current self-insured plan. The HDHP requires plan participants to pay all costs of medical care up to defined deductible limits. This plan will enforce the message to participants to manage their own health with an array of tools to assist them in becoming better consumers. Over time we expect this plan to result in lower overall medical costs to the Company. The level of cost savings will be dependent upon, among other things, the number of employees that choose this plan, and the level of utilization of medical care for those employees (i.e., the overall medical expense to the Company under the High Deductible plan versus the old plan for those particular employees and their families). The level of cost savings from the HDHP is expected to be minimal initially, and will be unknown for the longer-term until we have actual experience under the plan. The Company is also working closely with Mercer to evaluate and develop alternative strategies to reduce and/or maintain medical costs going forward, including:

- Plan Review – thorough review of plan metrics to evaluate any potential plan inefficiencies and target disease-management programs.

- Consideration of narrow or custom provider networks – seeking out the best quality, highest value hospital or physician group may result in lower unit costs and better long-term outcomes. The trade-off of less choice for plan participants will need to be weighed against the financial returns these networks offer.

In summary, the Company is taking proactive steps to reduce medical cost increases in the coming years, which the Company believes will help to offset some of the increases in medical expense going forward.

Q. Please continue with your discussion of the 2018 pro forma adjustments.

A. The next adjustment is Electric Adjustment (3.06) and Natural Gas Adjustment (3.04) - **Pro Forma Information Technology/Information Services Costs**, which includes the incremental costs associated with software development, application licenses, maintenance fees, and technical support for a range of information services programs. As discussed further by Mr. Kensok, 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. The effect of this adjustment decreases Idaho NOI by $203,000 electric and $53,000 natural gas.

Electric Adjustment (3.07) and Natural Gas Adjustment (3.05) – **Pro Forma Property Tax**, restates the 2016 test period accrued levels of property taxes to the 2018 rate period level using the most current information. As can be seen from my workpapers provided with the Company's filing, the property on which the tax is calculated is the property value as of December 31, 2017, reflecting the 2018 level of expense the Company will experience during the 2018 rate period. The net effect of this adjustment decreases NOI by $783,000 electric and $162,000 natural gas.

Electric Adjustment (3.08) and Natural Gas Adjustment (3.06) – **Pro Forma Capital Additions 2017 EOP**, reflects 2017 capital additions[15] together with the associated AD and ADFIT at a December 31, 2017 EOP basis. This adjustment also includes associated depreciation expense for these 2017 additions. In addition, the plant-in-service at December 31, 2016 AMA was adjusted to a December 31, 2017 EOP basis. Ms. Schuh describes this adjustment in detail within her testimony. The effect of this adjustment increases Idaho

[15] For each of the periods December 2017, 2018 and 2019, distribution-related capital expenditures associated with connecting new customers to the Company's system was excluded. An increase in revenues from growth in the number of customers from the historical test year to the 2018 and 2019 rate years are excluded, therefore, the growth in plant investment associated with customer growth was also excluded.

rate base $30,600,000 electric and $4,033,000,000 natural gas. The effect of this adjustment on Idaho NOI is a decrease of $3,499,000 electric and $976,000 natural gas.

Electric Adjustment (3.09) and Natural Gas Adjustment (3.07) – **Pro Forma Operation & Maintenance (O&M) Offsets,** includes O&M offsets related to specific plant additions, which were reviewed for any net O&M offsets that are expected in the 2018 rate period. Specific savings identified were included as a reduction to O&M costs and were discussed in the direct testimony of Ms. Rosentrater, with the capital asset with which the net offset relates. The net effect of this adjustment increases NOI by $216,000 electric and $8,000 natural gas.

Electric Adjustment (3.10) **Pro Forma Underground Equipment Inspection**, reflects underground equipment inspection expenses for Idaho planned during the rate year. The Company has implemented a program intended to quickly and efficiently inspect and update safety/decal markings on Company Padmount Transformers in accordance with regulatory guidance provided by the National Electric Safety Code, and IEEE. This program will facilitate the systematic updating of safety decals related to transformer safety decal/marking for the safety of the general public and utility crews, prevention of unauthorized/unintentional access to energized components of the distribution system, clearance of padmounts overgrown with vegetation (for example) and provide direction for locating padmount equipment. The net impact of this adjustment decreases electric NOI by $165,000.

Natural Gas Adjustment (3.08) - **Pro Forma Atmospheric Testing**, reflects the net increase in atmospheric corrosion testing and leak survey inspection expense during the rate year of $98,000. The effect of this adjustment decreases net operating income by $60,000.

Atmospheric Testing is an inspection program to find conditions in the Company's system that could lead to corrosion issues on customer meter sets. This program is a federally-mandated program that requires the Company to inspect all above-ground steel pipe at a frequency not to exceed three-years. This expense includes the inspection costs and follow-up remedial actions based an Atmospheric Corrosion (AC) inspection cycle completed one third of each jurisdiction per year.

Natural Gas Leak Survey Inspection (LS Program) is a gas operations program required by 49 CFR 192.723. The LS Program is accomplished utilizing a contractor specializing in gas leak survey. In accordance with 49 CFR 192.723, Avista leak surveys business districts every 12 months not to exceed 15 months, and residential areas at 20 percent annually (surveyed every 60 months not to exceed 63 months.)

Based on the historical survey cycles, Avista surveys approximately 4,900 miles of pipeline and associated meters annually.

<u>2019 Rate Year – Summary of Adjustments</u>

Q. Please now explain each of the 2019 Pro Forma adjustments included in Exhibit No. 12, starting on page 11 of Schedule 1 and page 9 of Schedule 2.

A. The Company has only included the incremental expenses above 2018 level expenses for the following major cost categories: 1) new plant investment, including depreciation and 2) property taxes, as well as, 3) non-executive labor expenses. The Company believes there will be additional increased expenses during the 2019 rate year not included here, and therefore the results of the 2019 pro forma incremental 2019 revenue requirement included in this filing is conservative.

The Company has provided workpapers, both in hard copy and electronic formats, outlining additional details related to each of the 2019 pro forma adjustments. A summary of each adjustment follows:

The first adjustment, starting on Exhibit No. 12, page 11, of Schedule 1 – Electric Adjustment (19.01) and Natural Gas Adjustment (19.01) - **Pro Forma Capital Additions 2018 AMA**, reflects all 2018 capital additions together with the associated AD and ADFIT at a 2018 AMA basis. This adjustment includes associated depreciation expense for the 2018 additions. In addition, the plant-in-service on a 2017 EOP basis is adjusted to a 2018 AMA basis. Ms. Schuh describes this adjustment in detail within her testimony. The net impact of this adjustment is a decrease in total rate base of $549,000 electric and $192,000 natural gas. The net effect of this adjustment on NOI is a decrease of $1,463,000 electric and $358,000 natural gas.[16]

Electric Adjustment (19.02) and natural gas adjustment (19.02) **Capital Additions 2018 EOP** adjusts 2018 capital additions together with the associated AD and ADFIT from a December 31, 2018 AMA basis to a December 31, 2018 EOP basis. Ms. Schuh describes this adjustment in detail within her testimony. The effect of this adjustment increases Idaho rate base $22,422,000 electric and $3,978,000,000 natural gas. The effect of this adjustment on Idaho NOI is a decrease of $1,634,000 electric and $408,000 natural gas.

Electric Adjustment (19.03) and natural gas adjustment (19.03) **Capital Additions 2019 AMA** reflects 2019 capital additions together with the associated AD and ADFIT at a 2019 AMA basis. This adjustment includes associated depreciation expense for the 2019 additions. In addition, the plant-in-service on a 2018 EOP basis is adjusted to a

[16] Reduction in net rate base is due to the increase in accumulated depreciation (A/D) and accumulated deferred federal income taxes (ADFIT) on total net plant on a 2018 AMA basis.

2019 AMA basis. Ms. Schuh describes this adjustment in detail within her testimony. The net impact of this adjustment is a decrease in total rate base of $6,887,000 electric and $2,146,000 natural gas. The net effect of this adjustment on NOI is a decrease of $1,044,000 electric and $229,000 natural gas.[17]

Electric Adjustment (19.04) and Natural Gas Adjustment (19.04) – **Pro Forma Property Tax**, reflects incremental property tax expense from 2018 to 2019 using the most current information. As can be seen from my workpapers provided with the Company's filing, the property on which the tax is calculated is the property value as of December 31, 2018, reflecting the 2019 level of expense the Company will experience during the 2019 rate period. The net effect of this adjustment decreases NOI by $376,000 electric and $75,000 natural gas.

The final adjustment, (19.05) - **Pro Forma Labor Non-Exec**, reflects incremental union and non-union wages and salaries from 2018 to 2019, excluding executive salaries.

For non-union employees, wages and salaries were adjusted to annualize the March 2018 estimated increase of 3.0%, and 10 months of the estimated March 2019 increase of

[17] Reduction in net rate base is due to the increase in A/D and ADFIT on total net plant on a 2019 AMA basis.

3.0%. For <u>union</u> employees, wages and salaries were adjusted to annualize the March 2018 estimated increase and include 10 months of the estimated increase for March 2019. The incremental increase above the 2018 Pro Forma labor Non-Exec adjustment was included in 2019 to reflect 2019 rate year levels. The net effect of this adjustment on NOI is a decrease of $402,000 electric and $113,000 natural gas.

<u>2018 and 2019 Final Summary</u>

Q. How much additional net operating income would be required for the State of Idaho electric operations to allow the Company an opportunity to earn its proposed 7.81% rate of return on a pro forma basis for the Two-Year Rate Plan?

A. For electric, the net operating income deficiency amounts to $11,380,000 for 2018 and $6,089,000 (incremental) for 2019, as shown on line 5, page 3 of Exhibit No. 12, Schedule 1. The resulting revenue requirement is shown on line 7 and amounts to $18,571,000 for 2018, or an increase of 7.53%, and $9,936,000 for 2019, or an increase of 3.75%.

Q. How much additional net operating income would be required for the State of Idaho natural gas operations to allow the Company an opportunity to earn its proposed 7.81% rate of return on a pro forma basis for the Two-Year Rate Plan?

A. The net operating income deficiency amounts to $2,134,000 for 2018 and $3,446,000 for 2019, as shown on line 5, page 3 of Exhibit No. 12, Schedule 2. The resulting revenue requirement is shown on line 7 and amounts to $3,480,000 for 2018, or an increase of 8.79% (5.68% on a billed basis), and $2,137,000 for 2019, or an increase of 4.96% (or 3.25% on a billed basis).

VI. ALLOCATION PROCEDURES

Q. Have there been any changes to the Company's system and jurisdictional procedures since the Company's last general electric and natural gas cases, Case Nos. AVU-E-16-03 and AVU-G-15-01, respectively?

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

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

A. Yes, it does.