Exhibit No. ___(EMA-1T)

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET NO. UE-14_____________

DOCKET NO. UG-14_____________

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 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. I have also attended several utility accounting, ratemaking and leadership courses.

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

A. As Manager of Revenue Requirements, aside from special projects, I am responsible for the preparation of normalized revenue requirement and pro forma studies

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

for the various jurisdictions in which the Company provides utility services. Since 2000, I have assisted or led 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 increase in rates based on the Company's electric and natural gas Attrition Studies. I will explain the overall methodology and results of the Company's Attrition Studies, providing overall attrition revenue requirement, rate base and net operating income balances for its electric and natural gas operations.

In addition, as a form of "cross check," I will also explain the Company's electric and natural gas results based on a pro forma basis for comparison purposes. The electric and natural gas Pro Forma Cross Check Studies provide operating results, including expense and rate base adjustments made to actual operating results and rate base. [2]

For informational purposes, I also will provide the results of the Company's electric and natural gas Attrition Studies for 2016. My testimony will explain how the Company has complied with past Commission Orders relating to: tracking Washington general rate case (GRC) expenditures; completing its Internal Audit of Utility expenditures; tracking separately it's Aldyl-A natural gas pipeline replacement program

[2] Certain adjustments are used in both the Attrition and Pro Forma studies, such as the Pro Forma Power Supply adjustment sponsored by Company witness Mr. Johnson, and certain transmission revenues, as discussed by Company witness Ms. Rosentrater, included in the Company's Energy Recovery Mechanism (ERM) as a part of net power supply and transmission expenses included in the authorized ERM base.

projects; and describing the Company's service and jurisdictional cost allocation methodologies.

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

A. Yes. I am sponsoring Exhibit Nos.____(EMA-2) through ___(EMA-7), which have been prepared under my direction. Exhibit Nos.____(EMA-2) (Electric) and ___(EMA-3) (Natural Gas) present the results of the Company's electric and natural gas Attrition Studies, as well as trend data used within the Attrition Studies. These 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 proposed revenue requirement, based on the Attrition Study analysis.

Exhibit Nos.__(EMA-4) (Electric) and __(EMA-5) (Natural Gas) provide the Company's Pro Forma Cross Check Studies and consist of worksheets, which show actual twelve-month-ending June 30, 2013 operating results, and pro forma electric and natural gas operating results and rate base for the State of Washington. These exhibits show the specific restating and pro forma adjustments used as a "cross check" in support of the electric and natural gas Attrition Study analysis.

Lastly, Exhibit No. __(EMA-6) provides the results of the Company's electric and natural gas Attrition Studies for 2016, and Exhibit No. __(EMA-7) provides the Company's Allocation Processes and Methodologies presentation material discussed later in my testimony.

II. COMBINED REVENUE REQUIREMENT SUMMARY

Electric and Natural Gas Results Summary:

Q. Would you please summarize the results of the Company's Attrition Studies for both the electric and natural gas operating systems for the Washington jurisdiction?

A. Yes. The results of the electric and natural gas Attrition Studies show 2015 rate period rates of return ("ROR") for the Company's Washington jurisdictional operations of 6.88% and 4.61%, respectively. Both return levels are below the Company's requested ROR of 7.71%. The incremental revenue requirement over and above rates currently in effect that is necessary to give the Company an opportunity to earn its requested ROR in 2015 is $18,201,000 for electric operations and $12,135,000 for natural gas operations. The overall base electric increase associated with this request is approximately 3.8%. The base natural gas increase is approximately 8.1%.[3]

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

A. The last authorized rate of return by this Commission for both the Company's electric and natural gas operations in its Washington jurisdiction was 7.64%, approved in Docket Nos. UE-120436 and UG-120437 (*Consolidated*), effective January 1, 2013.

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[3] The above revenue requirement amounts for both electric and natural gas operations are the incremental increases in 2015, reflecting the temporary base rate increases approved for 2014 of $14,054,000 for electric and $1,358,000 for natural gas. Assuming the 2014 temporary base rate increases would be permanent going forward (as the Company provides support for this base rate increase continuing on a permanent basis), produces the overall electric and natural gas incremental revenue requirements necessary for 2015 reflected above.

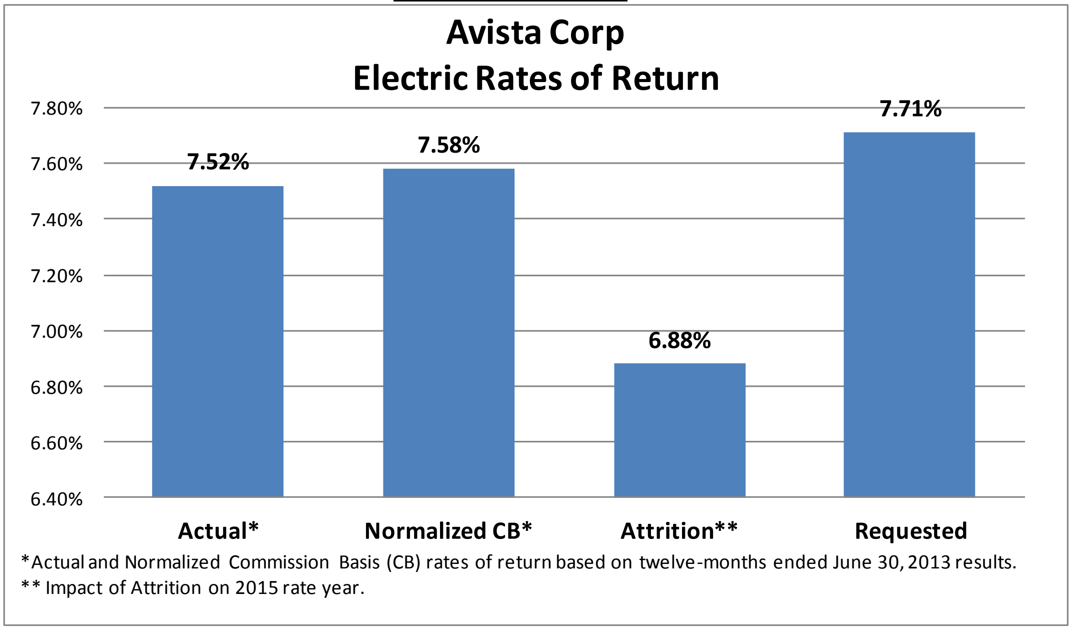
Q. On what test period is the Company basing its need for additional electric and natural gas revenue?

A. The test period being used by the Company is the twelve-month period ending June 30, 2013, presented on an attrition adjusted basis. Current authorized rates were based upon the twelve-months ending December 31, 2011 test year utilized in UE-120436 and UG-120437 (*Consolidated)*, adjusted per the settlement agreement approved by the Commission in those Dockets.

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

A. There are four different rates of return that are discussed. The actual ROR earned by the Company during the test period, the normalized or Commission Basis (CB) ROR results for the test period, the Attrition adjusted ROR determined in my Exhibit No.___(EMA-2), and the requested ROR. These returns are shown in Illustration No. 1 below:

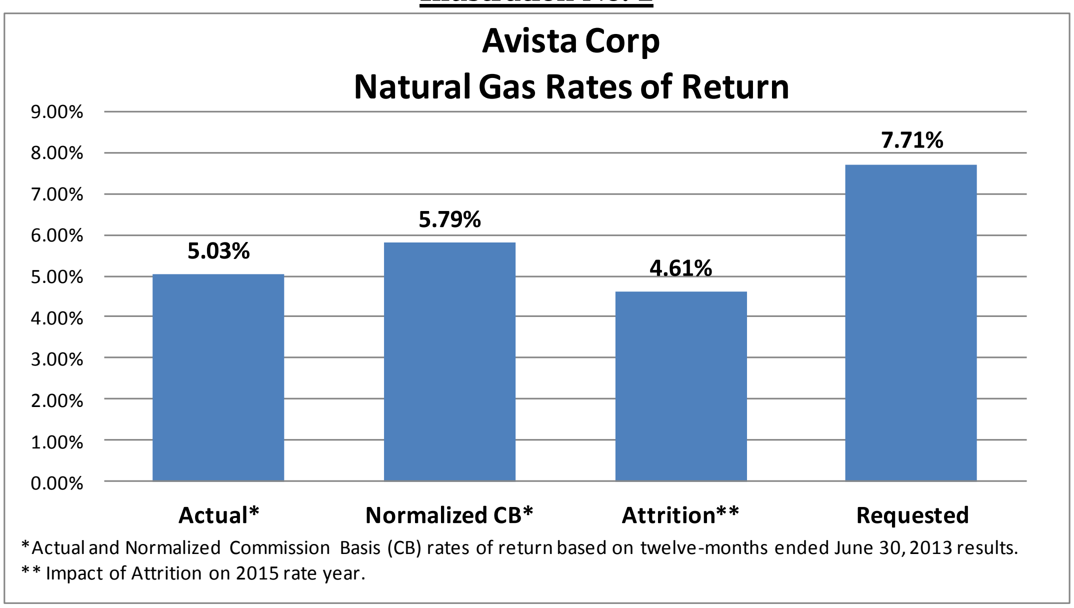
Illustration No. 1



Q. What are these same identified rates of return discussed in your testimony for the natural gas operations?

A. These same four rates of return for the natural gas operations (Actual, Normalized CB, Attrition and Requested) are shown below in Illustration No. 2.

Illustration No. 2



Primary Factors Driving Need for Washington Electric and Natural Gas Rate Relief:

Q. Please explain the primary factors driving the Company's need for its requested electric and natural gas increases.

A. The increase in overall costs to serve customers is driven primarily by two major factors: 1) the continuing need to replace and upgrade the facilities and technology we use every day to serve our customers, and 2) low revenue growth.

More specifically, as discussed further by Company witnesses Mr. Morris and Mr. Thies, in the next five years Avista will need to spend approximately $1.7 billion of capital on utility generation, transmission and distribution facilities and other requirements. This $1.7 billion represents over 70% of the current rate base of approximately $2.4 billion dedicated to serving customers today. As further discussed by Mr. Morris (and shown in Illustration No. 1 of his testimony), net plant investment for the last several years has been growing at a much faster pace than retail kilowatt-hour (kWh) sales and retail therm sales. Furthermore, this mismatch in the growth of net plant investment and sales is expected to continue to the future, requiring the Company to request increases in its retail rates to cover this increase in net plant investment since revenue growth is not sufficient to cover it.

Although the Company is basing its electric and natural gas revenue increases requested in this case based on its electric and natural gas Attrition Studies, for informational purposes, the specific 2013 (July-December 2013), 2014 and 2015 planned capital expenditures undertaken by the Company to expand and replace its generation, transmission and distribution facilities are explained by Company witness Mr. Kinney regarding production assets, and Company witness Ms. Rosentrater regarding transmission and electric distribution assets. Company witness Mr. Kensok discusses the Company's Information Technology capital projects, including the Company's replacement of its Customer Information System. Company witness Mr. DeFelice describes the general plant and gas distribution plant investments, as well sponsors supporting exhibits for all planned capital investment between July 2013 and 2015 described by each witness noted above.[4]

Q. Has there been other changes in net costs impacting the Company's need for rate relief in 2015?

A. Yes. As discussed by Company witness Mr. Johnson, production and transmission net expense changes reflect an overall net <u>reduction</u> to costs related to decreases in net power supply and transmission expenditures from that currently authorized. Mr. Johnson explains that the level of Washington's share of net power supply expense has decreased by approximately $6.5 million ($9.9 million on a system basis) from the level <u>currently in base rates</u>.

Our filing reflects an increase in operation and maintenance (O&M) and administration and general (A&G) expenses. Although the rate of growth in these expenses has been reduced, as explained by Mr. Morris.

[4] For Informational purposes Mr. DeFelice also provides information related to the planned 2016 capital investments.

III. ATTRITION STUDIES

Q. Before you begin explaining the results of the Company's electric and natural gas Attrition Study analysis, are other Company witnesses providing testimony relating to the attrition experienced by the Company?

A. Yes, Company witness Mr. Norwood discusses the merits of and need for the electric and natural gas Attrition Studies completed by the Company, and explains the underearning problem Avista would experience if attrition is not reflected in the rate making process. My testimony will focus on the calculation and use of the Attrition Study analysis to determine the requested revenue requirement included in this case.

Q. Please explain the purpose of the electric and natural gas Attrition Study analysis completed by the Company.

A. The purpose of the Attrition Studies filed by the Company in this proceeding are to determine the revenue deficiency in 2015 (as proposed in this filing), and the need for revenue increases effective January 1, 2015.

As discussed by Washington Utilities and Transportation Commission (WUTC) staff witness Mr. Elgin in Avista's rate filing, Docket Nos. UE-120436 and UG-120437, at Exhibit No. __T (KLE-1T), page 4, lines 7-13:

> Staff believes an attrition analysis is the proper approach in circumstances where a utility allege[s] it persistently fails to realize a fair return. An attrition study considers all elements of the ratemaking formula: revenues, expenses, rate base and rate of return in order to judge whether those relationships in the rate year will be materially different than those in the test year. An attrition study also is the proper means to adjust rate year loads for any effects of conservation programs.

Furthermore, at page 5, lines 9-12, Mr. Elgin adds:

> Staff believes an attrition adjustment is a proper tool to use when there is good evidence that the rate year will be materially different to the test period impacting the utility's opportunity to earn a fair return.

Q. Has Avista used an approach in calculating its Attrition Studies that is consistent with attrition study methods previously used in past rate case proceedings?

A. Yes. In the Company's previous 2012 general rate case, the Company retained Dr. Mark Lowry, President of Pacific Economics Group (PEG) Research, LLC., to prepare an electric Attrition Study to determine whether the Company would experience continued erosion in its earnings through the 2013 rate year (see Exhibit No. __(MNL-1T) in Docket No. UE-120436).[5]

As discussed by Dr. Lowry in the previous proceeding, in the early 1980s Avista [d/b/a Washington Water Power ("WWP")] had three rate cases in which attrition calculations, and attrition adjustments to the revenue requirement, were approved by the Commission (see U-81-15 & U-81-16, U-82-10 & U-82-11, and U-83-26). These attrition calculations accepted by the Commission for Avista were, in all cases, prepared by witnesses for WUTC Staff in which Staff relied on historical trends. In addition, as noted by Mr. Elgin in more recent testimony (see Dockets UE-111048 and UG-111049 at page 67), "An attrition adjustment analyzes actual historical trends in the growth rates of

[5]The Company used this same approach to produce and file the Company's 2013 natural gas Attrition Study (see Andrews' testimony and exhibits, Exhibit No. __(EMA-1T) in Docket No. UG-120437), and to reflect the continued erosion expected in 2014 absent additional rate relief (see Company witness Mr. Norwood discussion at Exhibit No. __(KON-7T), page 10 lines 8-19 in Docket No. UE-120436 and UG-120437 (*Consolidated*).

revenues, expenses, and rate base to estimate the erosion in rate of return caused by disparate growth in these categories."

As described further in Docket No. UE-120436, Dr. Lowry relied primarily on Avista's historical trends in arriving at his attrition calculation, and made use of Commission Basis Reports (CBR's) for prior years that included normalized cost and revenue data for Avista's Washington electric operations. As such, his analysis of historical cost trends relied on normalizing methods that have been approved by this Commission and reflected in the CBR's. More specifically, Dr. Lowry used prior Commission Basis Reports to develop trends in revenues, expenses, and rate base. He then applied the trends to amounts contained in the 2011 Commission Basis Report to develop trended values out to the 2013 rate effective period.

In this proceeding, as further described below, Avista has used a similar approach to prepare its electric and natural gas Attrition Studies using prior Commission Basis Reports to develop trends in revenues, expenses, and rate base, and then applying these trends to normalized or Commission Basis adjusted results at June 30, 2013, to develop trended values out to the rate effective period, or calendar year 2015.

Q. Due to the Settlement agreed to by the Parties in Docket Nos. UE-120436 and UG-120437, the revenue requirement approved by the WUTC was not based on a specified attrition study or amount. Did Staff, however, recognize that Avista would experience attrition?

A. Yes. As discussed by Mr. Elgin, starting at page 5 of Exhibit No. __T (KLE-7T), line 13:

> Staff conducted a detailed attrition study, and concluded Avista in all likelihood will experience attrition in the 2013 rate year…. In fact, the record evidence is clear that attrition is likely to prevail for the foreseeable future. Avista will continue to experience significant increases in its rate base at a time when there is little, if any, growth in revenue. The effect of these circumstances on Avista today and for the next few years will be attrition. In particular, absent a significant reduction in the amount of its capital budget, growth in load and decrease in operating expense, the most likely scenario for Avista in 2014 will be the results Avista is presenting today: a need for additional rate relief. The record evidence is clear on this fact.

As the Company continues to experience increases in costs, particularly significant increases in its rate base, at a time when there is a low growth in revenue, the Company has prepared electric and natural gas Attrition Studies to support its revenue requirement requested in this proceeding.

The electric and natural gas Attrition Studies are discussed further in the testimony that follows and provided in Exhibit Nos. __(EMA-2) (pages 1-10), and __(EMA-3) (pages 1-10). The Company has also provided workpapers, both in hard copy and electronic formats, providing the June 30, 2013 ending electric and natural gas Commission Basis results[6] and additional details related to the Attrition Study analysis.

[6] Included in these workpapers is a summary listing describing each CB restating and normalizing adjustment as well as workpapers supporting each adjustment.

<u>Electric Attrition Study</u>

Q. Please explain what is shown on page 1 of the Electric Attrition Study provided as Exhibit No._____(EMA-2).

A. Exhibit No._____(EMA-2), page 1, shows the calculation of the electric general revenue requirement, based on the Company's electric Attrition Study analysis, to earn the 7.71% rate of return proposed by the Company for its State of Washington electric operations. Page 1, shows the 2015 electric revenue requirement of $32,255,000 (column (e)), the temporary revenue increase of $14,054,000 presently in effect (column (f)), and the incremental revenue increase needed for 2015 of $18,201,000 (column (g)).

The Company's revenue requirement analysis demonstrates the need for the continuation of the 2014 temporary revenue increase of $14,054,000, and an incremental revenue increase for 2015 of $18,201,000.

Column **(a),** of page 1 labeled **Attrition Balances** shows the electric Attrition Rate Base and Attrition Net Operating Income balances, from page 5 of Exhibit No.____(EMA-2), column [K], lines 31 and 49.

Column **(b)** of page 1 labeled **Revenue Growth Factor** shows the revenue growth factor of 1.020771, as reflected from 5 of Exhibit No.____(EMA-2), column [K], line 55. In the case of retail revenue, my Attrition Study uses the Company's forecast of loads and customers for 2015 to estimate the expected revenue in 2015 at base rates effective January 1, 2013. Since the rate increase in this proceeding will be applied to the twelve-months-ending June 30, 2013 test period billing determinants, I have divided my rate year attrition-adjusted revenue requirement by the revenue growth factor to reflect the amount needed to be recovered from the test period level of retail loads and customers.

Column **(c)**, labeled **Attrition Adjusted Balances** shows the calculation of the $32,541,000 revenue requirement at the requested 7.71% rate of return based on the electric Attrition Study "Attrition Rate Base" and "Attrition Net Operating Income" balances in column (a) adjusted for the revenue growth factor from column (b).

Column **(d)**, labeled **After Attrition Adjustments** includes a reduction of $287,000 from the Attrition Revenue Requirement amount in column (c) resulting from adjustments necessary to restate the attrition-adjusted sub-total for offsets that are outside the attrition-adjusted revenue requirement proposed in this case.[7]

Column **(e)** labeled **Final Balances** shows the electric attrition adjusted revenue requirement, after reflecting the "After Attrition Adjustments" included in column (d), resulting in an adjusted electric attrition total of $32,255,000.

Column **(f)** shows the **2014 Temporary Rate Increase** approved in Docket UE-120436 of $14,054,000 currently in effect.[8] Due to the revenue requirement need in total,

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[7] These adjustments include (4.05) Lake Spokane Deferral 3-Year Amortization, which includes an amortization expense starting in 2015, and (4.06) O&M Offsets, reflecting reductions in operation and maintenance (O&M) which will occur in 2015 related to capital investments included for the period July 2013 through 2015. These adjustments represent activities which were not included in the 6/30/2013 normalized commission basis results used as the starting point of the Company's attrition analysis. (See Electric Pro Forma Adjustments section below for detailed description of these adjustments.) However, after completing our review of this case, the Company realized that the O&M Offset adjustment should have been included as a Pro Forma Cross Check Study adjustment only, and not included as an offset to the Attrition adjusted total.

[8] Order No. 09, Docket Nos. UE-120436 and UG-120436 (*Consolidated*), authorized the 2014 rate increase effective January 1, 2014 to December 31, 2014 on a temporary basis, with rates reverting back to 2013 levels absent any intervening Commission action. While the Commission found the 2014 rate increases to be fair, just, reasonable and sufficient on a temporary basis, the Commission stated "justification for our temporary approval lies primarily in Avista's representations that the Company will continue its multi-year capital expenditure program for 2014."

as shown in column (e) of $32,255,000, a portion of which relates to 2014 activities, the 2014 revenue increase should continue on a permanent basis, resulting in an incremental revenue requirement need as shown in column (g).

Column **(g)** labeled **2015 Revenue Requirement**, therefore, produces the final, 2015 incremental revenue requirement requested in this case of $18,201,000. The resulting percentage revenue increase above 2014 total general business revenues is 3.78%.

Q. Would you please explain page 2 of Exhibit No._____(EMA-2)?

A. Yes. Page 2 shows the proposed Cost of Capital and Capital Structure utilized by the Company in this case resulting in the weighted average cost of capital of 7.71%. Company witness Mr. Thies discusses the Company's proposed rate of return and the capital structure utilized in this case, while Company witness Mr. McKenzie provides additional testimony related to the appropriate return on equity for Avista.

Q. What does page 3 of Exhibit No._____(EMA-2) show?

A. Page 3 shows the derivation of the electric 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 35%.

Q. Would you now please explain pages 4 through 10 of Exhibit No.____(EMA-2)?

A. Yes. As further discussed in more detail below: pages 4 and 5 provide Avista's 2015 electric attrition revenue requirement calculation; pages 6 and 7 provide electric cost and revenue trend data for the period 2000-2012 per historical Commission Basis results of operations; page 8 provides summary data and adjustments to the historical data, and balances that develop the basis for the escalation factors shown on page 9; page 9 presents the annual electric growth rate analysis, and the escalation factors used in the Attrition Study; and the final page, page 10, shows the development of the electric weighted revenue growth rate from the June 2013 test period to the 2015 rate period.

2015 Electric Attrition Revenue requirement

Q. Please describe in more detail what can be found on pages 4 and 5 of Exhibit No. __(EMA-2).

A. Pages 4 and 5 present the normalized income statement and rate base for Washington electric operations, with the full cost, revenue and rate base detail that is found in Avista's June 2013 CBR. This report also provides the final result of the Company's electric attrition adjusted revenue requirement proposed in this filing.

Q. What is shown in column [A] on pages 4 and 5?

A. The first column labeled **[A] 06.2013 Commission Basis Report Restated Totals**, provides the results of the June 2013 Commission Basis Report (CBR) that includes normalized cost and revenue data for Avista's Washington electric operations for the period twelve-months-ended June 30, 2013. This column shows that on a CBR, normalized basis for this historical test period, the Company's earned ROR for its Washington electric operations was 7.58%, less than its authorized ROR of 7.64% for the 2013 period.

The next column labeled **[B] 06.2013 Normalized Net Power Supply**, is subtracted from column [A], removing all CBR normalized energy related cost and revenues (*e.g.* fuel, purchased power, sales for resale revenues) from the 06.2013 CBR values. (Pro forma level net power supply costs are added back later, as discussed further below.) This removal ensures only non-energy costs are trended to the 2015 rate period.

The next column labeled **[C] 06.2013 Ending Balance Plant Adjustment,** is an addition to column [A], restating plant additions included in the historical CBR test year on a June 30, 2013 AMA basis to an end of period (EOP) basis, together with the associated accumulated depreciation and deferred federal income taxes at a June 30, 2013 end of period basis.[9] This adjustment also includes the annual level of associated depreciation expense on all plant-in-service at June 30, 2013. This adjustment, sponsored by Mr. DeFelice and described further within his testimony, is necessary to represent the appropriate level of net plant rate base and expense to trend forward to the 2015 rate year.

The next column labeled **[D] Incremental Revenue Normalization Adjustment**, is an addition to column [A], adding Avista's 2013 electric revenue increase granted in its last general rate case, Docket No. UE-120436 as if it had been in place for the whole 12-month period. Revenues and expenses associated with the Schedule 91 Tariff Rider (DSM), Schedule 93 ERM rebate, and Schedule 59 Residential Exchange credit are excluded (since these items are recovered/rebated by separate tariffs and do not affect

[9] New plant investment related to customer growth/revenue growth for the test period was not adjusted to an EOP basis in this adjustment in column [C]. The revenue-related plant is, however, adjusted to an EOP basis in column [D].

attrition). This adjustment, discussed further by Company witness Ms. Knox, is necessary to include revenues at the 2013 approved base rate level.[10]

The next column, **[E] June 2013 Escalation Base,** is the sum of the previous columns [A] through [D], providing the June 2013 escalation base costs and rate base excluding net energy costs. This escalation base provides the balances from which the escalation factors, discussed below, are applied to determine the 2015 final attrition revenue requirement.

Q. Please now explain columns [F] through [H].

A. The end of period June 2013 plant and related items such as depreciation and property taxes need to be escalated two years to determine the expected costs for AMA 2015 (i.e., essentially from June 2013 to June 2015). O&M is not at end of period levels and therefore needs to be escalated two and one-half years to determine the expected costs for AMA 2015. Column **[F] Escalation Factor** shows the two year escalation rates (for net plant after DFIT, depreciation/amortization, and adjusted taxes other than income) and the 2 ½ year escalation rates (for adjusted O&M and adjusted other revenues). The determination of each of these factors is explained below.

These escalation factors are multiplied by the June 2013 base amounts from column [E], producing column **[G] Non-Energy Cost Escalation Amount**.

Adding column [G], the non-energy cost escalation amount to column [E], the June 2013 base amounts, produces column **[H] Trended 2015 Non-Energy Cost**, which

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[10] Included in Column [D] "Incremental Revenue Normalization Adjustment," is an adjustment to new plant investment during the test period related to customer growth/revenue growth, to adjust it to an EOP basis. Growth in new revenue plant is included here in order to match growth in plant costs with related growth revenue included in the Attrition Study analysis.

provides the 2015 trended amounts, prior to including the impact of 2015 pro formed net power supply and 2015 revenue growth.

Q. Please continue your discussion, describing the final columns [I] through [K].

A. Column, **[I] 06.2013 Pro-Formed Net Energy Cost**, adds the energy costs and sales for resale revenue produced by the Aurora$_{XMP}$ model as discussed by Company witnesses Mr. Johnson and Mr. Kalich. These values reflect fuel prices and market conditions for the 2015 rate year, but do not include the costs associated with incremental load growth from the historical test year to the 2015 rate year.

The next column, **[J] Revenue Growth,** reflects Avista's revenue growth between the test year and the 2015 rate year, by multiplying the retail revenue in column [E] times the weighted revenue growth **Escalation Factor** in column [F]. The weighted revenue growth escalation factor is determined on page 10 of Exhibit No. __(EMA-2). The power supply cost of the incremental load is priced at the pro-forma average sales and purchase price of power from Mr. Johnson's Exhibit No. ___(WGJ-4). Incremental revenue related expenses are computed on the incremental revenue using the components of the revenue conversion factor provided on page 3 of Exhibit No. __(EMA-2).

Adding columns [I] Pro-Formed Net Energy Cost and [J], Revenue Growth, to column [H] Trended 2015 Non-Energy Cost, produces the final column **[K] 2015 Revenue and Cost.** This column is the final column of the 2015 electric Attrition Study calculation, providing the 2015 attrition net operating income ($86,806,000) and attrition total rate base ($1,393,325,000), at lines 31 and 49, respectively. These totals are brought forward to page 1, column (a), of Exhibit No. __(EMA-2).

Q. Would you please explain what is shown on lines 54 to 56 of page 5 of Exhibit No. __(EMA-2)?

A. Yes. **Line 54** on page 5 of Exhibit No. __(EMA-2), shows the **Revenue Requirement** of $33,217,000 necessary for the Company to earn its requested 7.71% rate of return (ROR) in 2015, prior to the application of the growth factor.

Line 55 on page 5, provides the **Revenue Growth Factor** of 1.020771. Since the rate increase in this proceeding will be applied to the twelve-months-ended June 30, 2013 test period billing determinants, it is necessary to divide 2015 rate year, attrition-adjusted revenue requirement, by the revenue growth factor to reduce the revenue requirement to be applied to the test period level of retail loads. The 1.020771 is produced by dividing the sum of the retail revenues on lines 1 and 2 in column [K] by the sum of the retail revenues on lines 1 and 2 in column [E].

Dividing line 54 (2015 revenue requirement) by the electric revenue growth factor of 1.020771, produces the amount shown on **line 56**, **Attrition Adjusted Revenue Requirement** of $32,541,000[11], used by the Company in this proceeding.

Q. Please explain pages 6 and 7 of Exhibit No. __(EMA-2).

A. Pages 6 and 7 provide the annual normalized Commission Basis Reports, showing Washington electric expenses and rate base for the periods 2000 through 2012.

[11] This revenue requirement amount is prior to recognition of the "After Attrition" adjustments and 2014 temporary base rate increase, as discussed earlier in my testimony, and shown on page 1 of Exhibit No. __(EMA-2).

These data are used to determine the trends in rate base and expenses for the Attrition Study.

Q. What is included on page 8 of Exhibit No. __(EMA-2)?

A. Page 8 shows the development of electric adjusted data and balances for the period 2000-2012 used to calculate the growth rates and escalation factors on page 9. The escalation factors are intended to be used only on non-energy costs. Therefore it is necessary to remove the energy-related costs and revenues from the historical data. The Washington share of the normalized power supply costs and revenues from each year's Commission Basis Report (CBR) filing are deducted from the O&M and Other Operating Revenue in the historical reports. Similarly, adder schedule revenues and related expenses such as the DSM Tariff Rider and the Residential Exchange Credit that were included in the CBRs are also deducted from the historical results to create equivalent values for our trend analysis. (For the years 2004 and 2006, the CBR data already excluded DSM and residential exchange adjustments, so additional adjustments were not required.)

Results are presented for the following aggregated subtotals: Adjusted Operating Expenses; Total Depreciation/Amortization; Adjusted Regulatory Amortization; Adjusted Taxes Other Than Income Taxes; Net Plant After Deferred Income tax; Total Rate Base; and Adjusted Other Revenues, that are use in my trend calculations.

Q. Please explain page 9 of Exhibit No. __(EMA-2).

A. Page 9 shows the annual electric growth rate analysis, compound annual growth rates to 2012, the resulting 2 and 2 ½ year escalation factors, and the final escalation factors selected for use within the Attrition Study.

Q. Please discuss the compound growth rate escalation factors utilized within the Attrition Study, and why these particular growth rates were chosen.

A. The Company chose to use the five-year Compound Growth Rate of 2007-2012. Inspecting the results, it can be seen that the growth in cost categories, such as depreciation expense and net plant, has tended to be higher since 2007. Based on the Company's plan for higher capital expenditures in future years, it is appropriate to use the compound annual growth rates for the 2007-2012 period for rate base and depreciation expenses.

The escalation for the O&M expenses, however, has been set at a lower level to reflect the recent cost-cutting measures implemented by the Company, and the expectation that Avista will manage the growth in these expenses to a lower level in future years.[12] Although Avista's O&M/A&G costs have grown at an annual rate of approximately 8% per year for the past five years, we have used an annual growth rate of 4% per year for our Attrition Study.

Q. Please explain the final page of Exhibit No. __(EMA-2), page 10.

A. The final page of Exhibit No. __(EMA-2), page 10, shows the calculation of the growth in Avista's electric billing determinant index from June 2013 to 2015.

[12] Examples include the Voluntary Severance Incentive Plan (VSIP) initiated in 2012, discussed by Company witness Mr. Morris, and the pension and post retirement medical plan changes effective January 1, 2014, discussed by Company Ms. Feltes.

Column **[A]** shows the billing determinants from the June 2013 revenue model supporting the Incremental Revenue Normalization Adjustment on pages 4 and 5, column [D] discussed previously. These same billing determinants from the 2015 revenue forecast are shown in column **[B]**, then the percentage growth in the billing determinants from June 2013 to 2015 is calculated in column **[C]**. Column **[D]** shows the associated revenues from the June 2013 revenue model that were used to determine the weighting in column **[E]**. Finally, the weighted growth for each billing determinant is calculated in column **[F]** and the sum on line 19 is the 2015 escalation factor for retail revenue growth.

<u>Natural Gas Attrition Study</u>

Q. Before moving on to the Company's Natural Gas Attrition Study as provided in Exhibit No. __(EMA-3), are there similarities between the electric and natural gas studies?

A. Yes. The previous explanation of the exhibit pages and analysis for the electric Attrition Study are similar for the natural gas Attrition Study. I will describe briefly what can be found within Exhibit No. __(EMA-3), and any differences between various exhibit pages and analysis.

Q. Please explain what is shown on page 1 of the Natural Gas Attrition Study provided as Exhibit No._____(EMA-3).

A. Exhibit No._____(EMA-3), page 1, shows the calculation of the natural gas general revenue requirement based on the Company's natural gas Attrition Study analysis required to earn the 7.71% ROR proposed by the Company for its State of Washington natural gas operations. Page 1, shows the 2015 natural gas revenue requirement of $13,493,000 (column (e)), the 2014 temporary revenue increase of $1,358,000 (column (f)), and the incremental revenue increase needed for 2015 of $12,135,000 (column (g)).

Column **(a)**, of page 1 labeled **Attrition Balances** shows the natural gas Attrition Rate Base and Attrition Net Operating Income balances, from page 5 of Exhibit No.____(EMA-3), column [K], lines 31 and 47.

Column **(b)** of page 1 labeled **Revenue Growth Factor** shows the revenue growth factor of 1.021600, from page 5 of Exhibit No.____(EMA-3), column [K], line 55. As explained in the electric Attrition Study discussion above, my Attrition Study uses the Company's forecast of loads and customers for 2015 to determine the revenue in 2015. I have divided my rate year, attrition-adjusted revenue requirement by the revenue growth factor to reduce the revenue requirement to be applied to the test period level of retail loads and customers.

Column **(c)**, labeled **Attrition Adjusted Balances** shows the calculation of the $13,506,000 revenue requirement at the requested 7.71% rate of return based on the natural gas Attrition Study "Attrition Rate Base" and "Attrition Net Operating Income" balances in column (a) adjusted for the revenue growth factor from column (b).

Column **(d)**, labeled **After Attrition Adjustments** includes a reduction of $13,000 from the Attrition Revenue Requirement amount in column (c) to reflect O&M

offsets.[13]

Column **(e)** labeled **Final Balances** reflects the natural gas attrition adjusted revenue requirement, after reflecting the "After Attrition Adjustments" included in column (d), resulting in an adjusted natural gas attrition total of $13,493,000.

Column **(f)** shows the **2014 Temporary Rate Increase** approved in Docket UE-120437 of $1,358,000 currently in effect. Due to the revenue requirement need in total, as shown in column (e) of $13,493,000, a portion of which relates to 2014 activities, the 2014 revenue increase should continue on a permanent basis, resulting in an incremental revenue requirement need as shown in column (g).

Column **(g)** labeled **2015 Revenue Requirement**, therefore, produces the final, 2015 incremental revenue requirement requested in this case of $12,135,000. The resulting percentage revenue increase above 2014 total general business revenues is 8.09%.

Q. Would you please explain page 2 of Exhibit No._____(EMA-3)?

A. Yes. Page 2 shows the proposed Cost of Capital and Capital Structure utilized by the Company in this case, and the weighted average cost of capital 7.71%.

Q. What does page 3 of Exhibit No._____(EMA-3) show?

A. Page 3 shows the derivation of the natural gas net-operating-income-to-

[13] This adjustment includes (4.04) O&M Offsets, reflecting reductions in operation and maintenance (O&M) expense expected to occur in 2015 related to capital investments included for the period July 2013 through 2015. This adjustment represents activities which were not included in the 6/30/2013 normalized commission basis results used as the starting point of the Company's attrition analysis. However, after completing our review of this case the Company realized that the O&M Offset adjustment should have been included as a Pro Forma Cross Check Study adjustment only, and not included as an offset to the Attrition adjusted total.

ross-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 35%.

Q. Would you now please explain pages 4 through 10 of Exhibit No.____(EMA-3)?

A. Yes. Pages 4 and 5 provide Avista's 2015 natural gas attrition revenue requirement calculation; pages 6 and 7 provide natural gas cost and revenue trend data for the period 2000-2012 per historical Commission Basis results of operations; page 8 provides summary data and the development of the escalation factors shown on page 9; page 9 presents the annual natural gas growth rate analysis, and includes the escalation factors used in the Attrition Study on pages 4 and 5; and the final page, page 10, shows development of the natural gas weighted growth rate for the retail revenue from the June 2013 test period to the 2015 rate period.

2015 Natural Gas Attrition Revenue Requirement

Q. You stated before that the natural gas Attrition Study is very similar to the electric Attrition Study. Please point out any conceptual differences on pages 4 through 10 of Exhibit No. __(EMA-3) compared to the same pages of Exhibit No.___(EMA-2).

A. Gas costs are treated somewhat differently in the Company's natural gas rates compared to electric rates because of the Purchased Gas Adjustment (PGA) process. The cost of gas provided to natural gas customers is tracked through a deferral process which means that to the extent actual costs of gas are higher or lower than the amount included in customer revenue, the difference is set aside to be examined in the annual PGA filings, where updated gas costs are determined. The gas cost portion of rates is now entirely included in Schedule 150 that will not be changed as part of this general rate case, and there is no proposed change to gas costs through the Attrition Study.

Pages 4 and 5 include the **June 2013 Ending Balance Plant Adjustment** in column **[B], Incremental Revenue Normalization Adjustment** in column **[C],** and the exclusion of **Normalized Gas Costs and Revenues** is in column **[D]**. The weighted revenue growth escalation factors on page 10 include PGA revenue, therefore in order to determine the correct Revenue Growth in column [J] (pages 4 and 5), the gas cost related retail revenue was added back to the base before multiplying it by the **Escalation Factor** in column **[F]**. Transportation revenue growth was treated as a separate category, resulting in two revenue growth escalation factors; one for sales and one for transportation. Otherwise in all material respects the process is the same as the electric Attrition Study.

<u>Electric and Natural Gas Attrition Study Revenue Requirement Summaries</u>

Q. Referring back to Illustrations No. 1 and 2 on page 7, what were the actual and attrition-adjusted rates of return realized by the Company during the test period for its electric and natural gas operations?

A. For the State of Washington, the <u>actual</u> test period rates of return were 7.52% for electric and 5.03% for natural gas. The attrition-adjusted rates of return are 6.88% and 4.61% for electric and natural gas, respectively, under present rates. Thus, the

Company does not, on an attrition-adjusted basis for the test period, realize the 7.71% rate of return requested by the Company in this case.

Q. How much additional 2015 revenue requirement would be required for the State of Washington electric and natural gas operations to allow the Company an opportunity to earn its proposed 7.71% rate of return on an attrition-adjusted basis in 2015?

A. The revenue requirement deficiency totals $18,201,000 for electric and $12,135,000 for natural gas, as shown on line 7, page 1 of Exhibit Nos._____(EMA-2) and __(EMA-3), or an increase of 3.78% and 8.09%, for electric and natural gas respectively, over general business revenues as of 2014.

IV. PRO FORMA CROSS CHECK STUDIES

Q. Before explaining each of the Electric and Natural Gas Pro Forma Cross Check Studies prepared by the Company, please explain the purpose of these Pro forma Studies.

A. The purpose of the electric and natural gas Pro Forma Cross Check Studies is to provide a revenue requirement analysis based on individual restating and pro forma adjustments, and a separate independent analysis of Avista's need for revenue increases in 2015. These Pro Forma Studies act as a "cross check" to the reasonableness of the electric and natural gas Attrition Study results discussed previously in Section III. Attrition Studies. The Pro Forma Electric and Pro Forma Natural Gas Cross Check Studies are provided as Exhibit Nos. ___(EMA-4) and ___(EAM-5), respectively.

<u>Electric Pro Forma Cross Check Study</u>

Q. Would you please explain what is shown on page 1 of Exhibit No._____(EMA-4)?

A. Yes. Exhibit No.____(EMA-4), page 1, shows actual and pro forma electric operating results and rate base for the test period for the State of Washington. Column (b) of page 1 of Exhibit No.____(EMA-4) shows twelve-months ending June 30, 2013 actual operating results and components of the average-of-monthly-average rate base as recorded; column (c) is the total of all adjustments to net operating income and rate base; and column (d) is the pro forma adjusted results of operations, all under 2014 <u>existing</u> rates. Column (e) shows the revenue increase required which would allow the Company to earn a 7.71% rate of return for the 2015 rate period. Column (f) reflects total pro forma electric operating results.

Q. Would you please explain page 2 of Exhibit No._____(EMA-4)?

A. Yes. Page 2 shows the calculation of the $18,201,000 revenue requirement at the requested 7.71% rate of return based on the electric Pro Forma Cross Check Study.

Q. What does page 3 of Exhibit No._____(EMA-4) show?

A. Page 3 shows the proposed Cost of Capital and Capital Structure utilized by the Company in this case, and the weighted average cost of capital 7.71%, as previously explained in Section III. Attrition Studies.

Q. Please explain page 4 of Exhibit No._____(EMA-4).

A. Page 4 shows the same derivation of the net-operating-income-to-gross-revenue conversion factor as previously explained in Section III. Attrition Studies.

Q. Now turning to pages 5 through 10 of your Exhibit No._____(EMA-4), would you please explain what those pages show?

A. Yes. Page 5 begins with actual operating results and rate base for the twelve-months-ending June 30, 2013 test period 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 (2.17) on page 7. Individual pro forma adjustments are shown on page 8 in columns (3.00) though (3.07). The first column on page 9, labeled "Pro Forma Sub-total" is the subtotal of the previous columns (1.00) through (3.07).

Columns (4.00) through (4.03), on page 9 of Exhibit No._____(EMA-4), represent additional pro forma adjustments related to capital additions for July through December 2013, 2015 and 2015, as well as the pro forma adjustment related to energy efficiency (DSM). The last column on page 9, labeled "Pro Forma Cross Check Total," reflects the total electric revenue requirement for 2015 of $32,602,000 based on the use of restating and pro forma adjustments from the historical test year to the 2015 rate year.

This revenue requirement can be compared as a "cross check" to the revenue requirement determined using the Attrition Study of $32,541,000, which is shown at the bottom of the second column on page 10 of Exhibit No. __(EMA-4).

Column (4.04) on page 10 represents the difference of ($61,000) between the Pro Forma Cross Check Study and the Attrition Study.

Additional columns, shown on page 10 of Exhibit No._____(EMA-4), (4.05) and (4.06) are final pro forma adjustments to restate the attrition-adjusted sub-total for known offsets that are outside the attrition-adjusted revenue requirement proposed in this case. The final pro forma adjustment (4.07) reduces the revenue requirement for current 2014 revenues approved on a temporary basis, leaving the final column "Final Revenue Requirement Total" representing the proposed operating results and rate base for the test period, and the necessary incremental 2015 rate relief.

The Pro Forma Cross Check revenue requirement is reconciled to the Attrition Study revenue requirement in order to establish revenue, expenses and rate base numbers that can be used as inputs to the Company's cost of service study prepared by Ms. Knox.

Each of the Commission Basis, restating and pro forma adjustments are discussed in the testimony that follows, and the Company has also provided workpapers, both in hard copy and electronic formats, outlining additional details related to each of the adjustment.

<u>Standard Commission Basis and Restating Adjustments</u>

Q. Would you please explain each of these adjustments, the reason for the adjustment and its effect on test period State of Washington net operating income and/or rate base?

A. Yes, but before I begin, I will note the **Results of Operations** column (1.00), reflects the Company's actual operating results and total net rate base experienced by the Company for the twelve-month period ending June, 30 2013 on an average-of-monthly-average (AMA) basis.[14] Columns following the Results of Operations column (1.00) 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 amounts reflected in the actual June 30, 2013 results.

Q. Please continue with your explanation of each adjustment and its effect on test period net operating income and/or rate base.

A. The first adjustment, column (1.01) on page 5, entitled **Deferred FIT Rate Base,** adjusts the DFIT rate base balance included in the Results of Operations column (1.00) to the adjusted DFIT balance, as shown within my workpapers provided with the Company's filing. This adjustment to rate base is necessary to reflect various revisions related to the final 2012 tax return filed in 2013 and certain prior period tax return audit adjustments. Accumulated DFIT 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. These amounts are reflected on the average-of-monthly-average balance basis. The effect on Washington rate base for this adjustment is a decrease of $1,890,000. A decrease to Washington net

[14] This column, reflects an actual results of operations rate of return of 7.71% as shown on page 1 of Exhibit No. __(EMA-4), at line 49. This 7.71% excludes the Voluntary Severance Incentive Program (VSIP) costs, however, as non-recurring and was excluded from recovery from customers in 2013 and 2014. However, the benefits of the VSIP initiative are reflected in the electric and natural gas operating results in this proceeding as the labor expense of those individuals who participated in the VSIP initiative were excluded from the 2015 pro forma level of labor expense. Although the VSIP costs were excluded from recovery from customers and the operations column (1.00), it is appropriate to include the VSIP costs in the calculation of actual operating results at twelve-months-period-ending June 30, 2013, resulting in an actual ROR of 7.52%, as shown on page 1 of Exhibit No. __(EMA-4), at line 50.

operating income of $18,000 is due to the Federal income tax (FIT) expense on the restated level of interest on the change in rate base[15].

The adjustment in column (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 rate base by $8,768,000. Washington net operating income (NOI) decreases by a total of $169,000; including reductions to operating income of $129,000 for expenses, and $85,000 of FIT expense related to the restated level of interest on the change in rate base, and an increase in operating income for FIT expense of $45,000.

Adjustments included in the Deferred Debits and Credits consolidated adjustment are those necessary to reflect restatements from actual results based on prior Commission orders, and are explained below. For consistency with prior rate case filings, a description of each previously separated adjustment is included below.

The following items are included in the consolidation:

- **<u>Colstrip 3 AFUDC Elimination</u>** 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 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.

[15] 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 <u>each</u> individual adjustment. The restated debt interest impact per individual rate base adjustment can be seen on Line 27 of Exhibit No. EMA __(EMA-4).

There is no adjustment necessary for the effect of the reallocation on Washington rate base, as the appropriate amount is accurately reflected in the results of operations column.

- **<u>Colstrip Common AFUDC</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 is also included in the results of operations accurately reflecting the average-of-monthly-averages amount for the test period. No adjustment is necessary.
- **<u>Kettle Falls Disallowance</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 is necessary.
- **<u>Settlement Exchange Power</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. However, the production rate base and accumulated deferred FIT amounts within results of operations are reflected on an twelve-months ending June 30, 2013 test period AMA basis. The use of AMA for the <u>rate</u> period was ordered in Order No. 01 in Docket No. U-071805. To adjust the production rate base and accumulated deferred FIT amounts to reflect an AMA 2015 rate period basis, the effect on Washington rate base is a decrease of $5,024,000.
- **<u>Restating CDA Settlement Deferral</u>** adjusts the net assets and DFIT balances reflected in results of operations associated with the 2008/2009 past storage and §10(e) charges deferred for future recovery, to a 2015 AMA basis. A ten-year amortization expense, as approved in Docket No. UE-100467, of the

CDA Settlement Deferral is accurately reflected in results of operations. The effect on Washington rate base is a decrease of $247,000.

- **Restating CDA/SRR (Spokane River Relicensing) CDR Deferral** adjusts the net assets and DFIT balances reflected in results of operations associated with the CDA Tribe settlement 4(e) Spokane River relicensing conditions deferred for future recovery, to the proper 2015 AMA basis. 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. The effect on Washington rate base is a slight increase of $3,000 to remove the effect of DFIT previously included, but removed per the 2012 Tax Return Audit.
- **Restating Spokane River Deferral** adjusts the net asset and DFIT balances reflected in results of operations related to the Spokane River deferred relicensing costs deferred for future recovery, to a 2015 AMA basis. A ten-year amortization expense of the Spokane River Deferral, as approved in Docket No. UE-100467 is accurately reflected in results of operations. The effect on Washington rate base is a decrease of $119,000.
- **Restating Spokane River PM&E Deferral** adjusts the net asset and DFIT balances reflected in results of operations related to the Spokane River deferred PM&E costs deferred for future recovery, to a 2015 AMA basis. 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. The effect on Washington rate base is a decrease of $75,000.
- **Restating Montana Riverbed Lease** adjusts the net asset and DFIT balances reflected in results of operations related to the costs associated with the Montana Riverbed lease settlement deferred for future recovery, to a 2015 AMA basis. In the Montana Riverbed lease settlement, the Company agreed to pay the State of Montana $4.0 million annually beginning in 2007, with annual inflation adjustments, for a 10-year period for leasing the riverbed under the Noxon Rapids Project and the Montana portion of the Cabinet Gorge Project. The first two annual payments were deferred by Avista as approved in 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. This restating adjustment also includes the increase in the annual lease payment expense for the additional annual inflation. This adjustment decreases Washington net operating income by $156,000 and decreases rate base by $1,100,000.
- **Restating Lancaster Amortization** adjusts the net asset and DFIT balances reflected in results of operations related to the 2010 ($6.8 million Washington) deferred Lancaster plant Power Purchase Agreement (PPA), to a 2015 AMA basis. A five-year amortization expense of the Lancaster deferral ends in November 2015, therefore a reduction in expense for the pro forma period from that reflected in results of operations reduces expense and increases Washington

net operating income by $73,000. The effect on Washington rate base is a decrease of $2,207,000.

- **<u>Customer Advances</u>** 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. The reduction to rate base per results of operations is accurately reflected at approximately $250,000; therefore no adjustment is necessary to rate base.
- **<u>Customer Deposits</u>** reduces electric rate base by the average-of-monthly-averages of customer deposits held by the Company, as ordered by this Commission in Docket UE-090134. The reduction to rate base per results of operations is accurately reflected at approximately $1,710,000; 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 0.14%. The effect on Washington operating income is a decrease of $1,000.

In summary, as noted above, the net impact on a consolidated basis of the adjustments described above decreases Washington net operating income by $169,000, and decreases Washington rate base by $8,768,000.

Q. Please continue describing the remaining adjustments on page 5.

A. The adjustment in column (1.03), **Working Capital**, restates the working capital balance reflected in the Company's Results of Operations column (1.00), to the adjusted working capital balance proposed below.

The Company uses the Investor Supplied Working Capital (ISWC) methodology to calculate the amount of working capital reflected in its actual results of operations at twelve-months-ended June 30, 2013 on an AMA basis, resulting in an electric working capital balance of $18.753 million. This methodology is consistent with the ISWC methodology utilized in the past three general rate cases, Docket Nos. UE-100467, UE-110876 and UE-120436. The Company, however, in this proceeding is proposing a few refinements in its calculation, which increases the Company's actual working capital balance to $33.968 million, an increase in net rate base of $15.215 million.

Q. Please describe the refinements to the methodology used to calculate the Company's working capital proposed in this proceeding.

A. The Company proposes the following refinements to its calculation of working capital as set forth below:

(1) The Company proposes that pension and other post-retirement benefits liabilities and the associated regulatory asset balances be included as current assets and current liabilities rather than in investments.

(2) The Company proposes that accumulated deferred income tax balances associated with its pension and other post-retirement benefits liabilities and regulatory assets be classified as current assets and current liabilities, along with those underlying balances.

Q. Please describe the rationale supporting these refinements as proposed to the classification of pension and other post-retirement benefits liabilities and associated regulatory assets.

A. The Company proposes that pension and other post-retirement benefits liabilities, associated regulatory asset balances, and associated accumulated deferred income tax balances be included as current assets and current liabilities rather investments because investors have supplied the necessary capital through contributions to its plans in excess of its accounting expense.

Pension and other post-retirement benefits liabilities (FERC account 228.3) and the associated regulatory assets (included in FERC account 182.3) represent the difference between the amount the Company has contributed to its pension and post-retirement benefit plans and the amount the Company has recorded to expense for those same plans. Differences between cumulative expense and contributions can arise as a result of funding requirements and funding policies. For example, the federal Pension Protection Act of 2006, as amended, has required the Company to contribute significant amounts to its pension plan since enacted, and cumulative contributions exceed cumulative expense recognized to date.

For ratemaking purposes, the Company recovers pension and post-retirement costs based on the amount recorded to expense. Investor capital is impacted for any difference between the amounts contributed to the plans and the amounts included in rates as expense, therefore investors have borne the cost of financing any incremental contributions.

Although the FERC Uniform System of Accounts requires classification of these balances as non-current, contributions are made to the plans and amounts are amortized to expense each year. Thus, there are current activities associated with these balances despite their non-current balance sheet classification.

Q. Has the WUTC Staff supported and the Commission approved a similar methodology in other proceedings?

A. Yes. Most recently, in WUTC v. PacifiCorp, Docket UE-130043, Pacificorp, through Company witness Mr. Stuver, proposed this same treatment of post-retirement benefits of current assets and liabilities. WUTC Staff witness Mr. Zawislak, in Exhibit No. ___(TWZ-1), at page 3, lines 20-22, fully supported the reclassification of post-retirement benefits to the current assets and liabilities, stating:

> Mr. Stuver's treatment of post-retirement benefits achieves a proper balance of ratepayer interests and allows investors to earn a return on the net unamortized funds they have contributed to Company employees' post-retirement benefits."

The Commission supported this refinement to Pacificorp's ISWC methodology, approving this change at Order 05, page 93, paragraph 240, which stated:

> As Mr. Zawislak testifies, PacifiCorp's ISWC adjustment is a refinement to the methodology that corrects the calculation of ISWC with respect to pensions and other post-retirement benefit liabilities including the associated regulatory assets and derivative assets and liabilities. We determine that PacifiCorp's adjustment to working capital relying on the ISWC approach is supported by the record and should be allowed.

An additional example showing support that this classification is consistent with prior WUTC Commission precedent can be found in Docket UT-950200. In that case, the Commission allowed U S WEST Communications, Inc. a $70 million increase in rate base for the prudently incurred Pension Asset (offset by a $38 million decrease in rate base as a result of a negative ISWC calculation).[16]

As noted above, the effect of this adjustment on Washington rate base is an increase of $15,215,000. An increase to Washington net operating income of $147,000 is due to the FIT expense of the restated level of interest on the change in rate base.

Q. Please continue describing the remaining adjustments on page 5, starting at column (2.01).

A. The next adjustment, included after Working Capital, is labeled column (2.01), **Eliminate B & O Taxes**, and eliminates the revenues and expenses associated

[16] *WUTC v. U S WEST Communications, Inc*., Docket UT-950200, Fifteenth Suppl. Order at 70 (April 11, 1996).

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 net operating income by $45,000.

The adjustment in column (2.02), **Restate 2013 Property Tax**, restates the accrued property tax during the test period to actual property tax paid during 2013. Property tax expense for 2013 was based on actual plant balances as of December 31, 2012. The effect of this adjustment is to decrease Washington net operating income by $655,000. Please see pro forma discussion below, Adjustment (3.06) Pro Forma Property Tax, for additional amounts pro formed, increasing the property tax expense included in the Company's filing to the 2015 rate year level of expense.

The last adjustment on page 5, shown in column (2.03) **Uncollectible Expense**, restates the accrued expense to the actual level of net write-offs for the test period. The effect of this adjustment is to decrease Washington net operating income by $462,000.

Q. Please turn to page 6 and explain the adjustments shown there.

A. The first adjustment shown on Page 6 in column (2.04), **Regulatory Expense**, restates recorded regulatory expense for the twelve-months-ended June 30, 2013 to reflect the UTC assessment rates applied to revenues for the test period and the actual levels of FERC fees paid during the test period. The effect of this adjustment is an increase to Washington net operating income of $34,000.

The adjustment in column (2.05), **Injuries and Damages**, which is a restating adjustment that replaces the accrual with actuals to obtain the 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 is to decrease Washington net operating income by $183,000.

The adjustment in column (2.06), **FIT/DFIT/ITC/PTC Expenses**, adjusts the FIT and DFIT calculated at 35% within Results of Operations by removing the effect of certain Schedule M items, revising the Section 199 Manufacturing Permanent M Deduction accrued during the test period to the actual Schedule M deduction taken per the 2012 tax return filed in September 2013, and adjusts the appropriate level of production tax credits and investment tax credits on qualified generation.

The net FIT and production tax credit adjustments increase Washington net operating income by $735,000. Adjusting for the proper level of deferred tax expense for the test period increases Washington net operating income by $18,000. This adjustment also reflects the proper level of amortized investment tax credit for the test period decreasing Washington net operating income by an additional $2,000. Therefore, the net effect of this adjustment, all based upon a Federal tax rate of 35%, is to increase Washington net operating income by $751,000.

The adjustment in column (2.07), **Office Space Charged to Subsidiaries**, removes a portion of the office space costs (including, but not limited to 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.) using 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. The effect of this adjustment is to increase Washington net operating income by $15,000.

The adjustment in column (2.08), **Restate Excise Taxes**, removes the effect of a one-month lag between collection and payment of taxes. The effect of this adjustment is to increase Washington net operating income by $112,000.

The adjustment in column (2.09), **Net Gains/Losses**, reflects a ten-year amortization of net gains realized from the sale of real property disposed of between 2003 and June 30, 2013. This restating adjustment is made as a result of the Commission's Order in Docket No. UE-050482. The effect of this adjustment is to increase Washington net operating income by $49,000.

The adjustment in column (2.10), **Revenue Normalization 2013**, is an adjustment taking into account known and measurable changes that include revenue repricing (including the 2013 authorized rates approved in Docket No. UE-120436), weather normalization and a recalculation of unbilled revenue for 2013 base rate increases. Revenues associated with the Schedule 91 Tariff Rider and Schedule 59 Residential Exchange are excluded from pro forma revenues, and the related amortization expense is eliminated as well.[17] Ms. Knox is sponsoring this adjustment. The effect of this particular adjustment is to increase Washington net operating income by $4,683,000. (A pro forma adjustment reflecting the 2014 temporary base rate increase currently in effect is discussed later in my testimony.)

The last adjustment on page 6 included as column (2.11), **Eliminate WA Power Cost Deferral,** 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 costs pursuant to the commission-approved deferral and recovery mechanism. The adjustment removes the ERM surcharge 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 is to increase Washington net operating income by $4,387,000.

Q. Please turn to page 7 and explain the adjustments shown there.

A. Page 7 starts with the adjustment in column (2.12), **Nez Perce Settlement Adjustment**, which reflects an increase in production operating expenses. An agreement was entered into between the Company and the Nez Perce Tribe in 1999 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.

[17] The impact of this adjustment is also included in the Company's electric Attrition Study. See column [D], page 4 of Exhibit No. __(EMA-2).

This restating adjustment is consistent with Docket No. UE-011595. The effect of this adjustment is to decrease Washington net operating income by $8,000.

The adjustment in column (2.13), **Miscellaneous Restating Adjustments**, removes a number of non-operating or non-utility expenses associated with dues and donations, etc., included in error in the test period actual results, and removes or restates other expenses incorrectly charged between service and or jurisdiction totaling approximately $22,600.

The Company also removed 50% of director meeting expenses, as ordered in Docket No. UE-090134, and restates director fee expenses to reflect a 90% Utility / 10% non-utility split, totaling approximately $18,600. The effect of this adjustment is to increase Washington net operating income by $27,000.

Q. As noted above, the Company removed 10% of Director Fee expenses. What is the basis for removing 10% of these costs?

A. In 2013, the Company requested each of its Directors, based on their actual experience, to estimate the time they spend on utility versus non-utility duties and responsibilities. The responses from the Directors indicated that, in the aggregate, approximately 90% of the Directors' time is dedicated to utility matters, and approximately 10% to non-utility. This 90/10 split is consistent with the average split that has been used in recent years by Avista's officers.

Q. Please continue with your explanation of adjustments on page 7.

A. The adjustment in column (2.14), **Restating Incentive Expenses**, restates actual incentives included in the Company's test period ending June 30, 2013, reducing overall expense by approximately $3.0 million. This reduction in incentive expense is, in part, due to a change in Company policy regarding incentive allocation between Capital and O&M. In prior years, 100% of the incentive plan payout was charged to O&M accounts. Effective January 1, 2013 approximately 40% is being charged to Capital projects, consistent with actual employee overall labor charges.

The overall incentive expense included in the Company's filing is also reduced from that included in the test year, as the expense amount included is based on the expected incentive payout in 2015 allocated to expense, reduced to reflect a six-year average of payout percentages. For non-officer incentives, this is calculated by using the 2015 level of labor expense (determined in Pro Forma Labor adjustment 3.02) multiplied by the payout incentive opportunity per the Company's current incentive plan (or 12% overall) to determine the incentive payout opportunity, multiplied by the six-year average of actual percentage payouts for the periods 2007-2012 (or 72%). For officers, the incentive amount included in the Company's filing is based on 2013 incentives accrued for officers (paid Q-1 of 2014), based on operating performance metrics defined in the Officer Short-Term Incentive Plan (STIP) related to O&M targets[18]. This amount was then multiplied by the six-year average of actual percentage payouts for the periods 2007-2012 (or 28.84%). The net effect of this adjustment increases Washington net operating income by $1,979,000.

Q. Please continue with your explanation of adjustments on page 7.

[18] Officer STIP based on earnings per share targets are excluded from this calculation. All long-term incentives and short-term incentives based on earnings per share targets are borne by shareholders.

A. The adjustment in column (2.15), **Colstrip/CS2 Maintenance**, annualizes the amortization expense included in the Company's test period related to the 2012 deferred Colstrip and Coyote Springs 2 thermal maintenance expense. A 4-year Amortization of the 2012 deferral amount approved in Docket No. UE-120436 started January 1, 2013, expiring on December 31, 2016. The effect of this adjustment is to decrease Washington net operating income by $358,000.

The adjustment in column (2.16), **Restate Debt Interest**, restates debt interest using the Company's pro forma weighted average cost of debt, as outlined in the testimony and exhibits of Mr. Thies, 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 or the test period decreases Washington net operating income by $1,203,000.

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.

The last restating adjustment shown on page 7 is included in column (2.17), **Restating June 30, 2013 Capital EOP**. This adjustment restates plant additions included in the test year on a June 30, 2013 AMA basis to an end of period basis, together with the associated accumulated depreciation and deferred federal income taxes at a June

30, 2013 end of period basis, as described further by Mr. DeFelice.[19] This adjustment also includes the annual level of associated depreciation expense on all plant-in-service at June 30, 2013.[20] The effect of this adjustment on Washington net operating income is a decrease of $415,000. The effect on Washington rate base is an increase of $35,200,000.

The last column on page 7, entitled **Restated Total**, subtotals all the preceding columns (1.00) through column (2.17). These totals represent actual operating results and rate base plus the standard normalizing adjustments that the Company includes in its annual Commission Basis reports. However, the Restated Total column does not represent June 30, 2013 test period results of operation on a normalized commission basis. Differences between certain restating adjustments included in normalized Commission Basis Reports (CBRs) versus those included here, include but not limited to, removal of CBR Power Supply (as the Power Supply net expense adjustment is included later as Pro Forma Power Supply Adjustment (3.0)); inclusion of 2013 annualized revenues (described in adjustment (2.10) Revenue Normalization above); inclusion of debt interest restated based on the Company's proposed weighted cost of debt (described in adjustment (2.16) Restate Debt Interest above) and inclusion of net plant investment on an end-of-period basis (described in adjustment (2.17) Restating June 30, 2013 Capital

[19] The impact of this adjustment is also included in the Company's electric Attrition Study. See column [C], page 4 of Exhibit No. __(EMA-2).

[20] As noted by Staff witness Mr. Elgin in his testimony related to the PSE rate case (Docket Nos. UE-111048 and UG-111049), Exhibit No. KLE-1T, pp. 65-66, the Commission has, under certain circumstances, accepted end-of-period balances for rate base to address growing investments, rising costs and regulatory lag. (See WUTC v. Washington Natural Gas Co., Cause No. U-80-111). He also referred to language from an earlier Order for Puget Sound Power & Light which, while rejecting year-end rate base, provided that, "[The Commission] has not, however, discounted the validity of year-end rate base where special conditions exist, such as unusual growth in plant at a faster pace than customer growth and customary rate making is deficient." (See WUTC v. Puget Sound Power & Light Co., Cause No. U-73-57, 6th Supp. Order at 9 (Oct. 25, 1974).)

EOP above).[21] Each of the adjustments noted above have been included consistent with past general rate case filings by the Company. For Commission Basis Report results of operations for test period ending June 30, 2013 (resulting in a 7.58% rate of return), please see Exhibit No. __(EMA-2), page 5, line 50.

Pro Forma Adjustments

Q. Please explain each of the pro forma adjustments shown on page 8.

A. The adjustment in column (3.00), **Pro Forma Power Supply**, was made under the direction of Mr. Johnson and is explained in detail in his testimony. This adjustment includes pro forma power supply related revenue and expenses to reflect the twelve-month period January 1, 2015 through December 31, 2015, using historical loads.[22] Mr. Johnson's testimony outlines the system level of pro forma power supply revenues and expenses that are included in this adjustment. This adjustment calculates the Washington jurisdictional share of those figures, and also, eliminates power supply costs related to the Clearwater Paper cogeneration purchase directly assigned to Idaho, and directly assigned Washington Energy Independence Act (EIA) renewable energy credits (RECs), tracked in a separate REC deferral. The net effect of the power supply adjustments increase Washington net operating income by $1,483,000.

The adjustment in column (3.01), **Pro Forma Transmission Revenue/Expense,**

[21] The restated total also includes additional updates, such as increases in expense necessary to annualize certain expenses included in the test period as restating adjustments, (i.e. Colstrip/CS2 maintenance), includes proposed changes to working capital related to inclusion of pension related regulatory assets and liabilities, and reductions to incentive expense recognizing portions capitalized starting 1/1/2013 and to reflect a 6-year average pay-out for the level of expense included.

[22] The impact of this adjustment is also included in the Company's electric Attrition Study. See column [I], page 4 of Exhibit No. __(EMA-2).

was made under the direction of Ms. Rosentrater and is explained in detail in her testimony. This adjustment includes pro forma transmission-related revenues and expenses to reflect the twelve-month period January 1, 2015 through December 31, 2015.[23] The net effect of the transmission revenue and expense adjustments decrease Washington net operating income by $3,531,000.

The adjustment in column (3.02), **Pro Forma Labor-Non-Exec**, reflects known and measurable changes to test period union and non-union wages and salaries[24], excluding executive salaries, which are handled separately in adjustment (3.03). For non-union employees, test period wages and salaries are restated to include the March 2013 overall actual increase of 2.8% on an annualized basis, the March 2014 overall increase of 2.8% (approved by the Compensation Committee of the Board of Directors[25]), and 10 months of the planned March 2015 increase of 2.8%. Ms. Feltes discusses the Company's overall compensation plan and notes that a minimum increase in 2015 will be presented to the Compensation Committee of the Board of Directors for approval at the Board's May 2014 Board meeting.

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[23] The impact of certain transmission revenues (i.e. transmission revenues included in authorized ERM net energy costs) included in this adjustment are also included in the Company's electric Attrition Study. See column [I], page 4 of Exhibit No. __(EMA-2).

[24]VSIP labor expense, as previously discussed, of those individuals who participated in the VSIP initiative were excluded in adjustment (3.02) for determining the 2015 pro forma level of labor expense included in this adjustment. The costs of the VSIP initiative were already excluded from actual results of operations, as previously noted.

[25] In May, 2013, the Compensation Committee agreed to set a minimum salary increase for non-union employees of 2.5% for 2014, based on the survey data received. In November 2013 based on updated market data, 2.8% for non-union employees was ultimately approved to be effective March 1, 2014.

Also included in this adjustment are the actual 2013, and planned 2014 and 2015 union contract increases for each year.[26] The methodology behind this adjustment is consistent with that used in the Company's previous Docket No. UE-120436. The effect of this adjustment on Washington net operating income is a decrease of $1,096,000.

The adjustment in column (3.03), **Pro Forma Labor-Executive**, reflects known and measurable changes to reflect an annualized 2013 level of allocated executive officer salaries (effective March 2013). However, the Company has included utility and non-utility allocation percentages planned for 2015. The net result of these changes increases the executive compensation expense slightly from that included in the Company's historical test period. No additional increases in executive labor for 2014 or 2015 planned expenses have been included in this filing.

The basis for labor allocations in the current rate case is based on an estimate by each executive of the time to be spent on non-utility activities based on their historical actual experience and plans for future time periods (including AERC and AEL&P)[27]. As we progress through the year, each executive updates the timekeeping system bi-weekly with actual time spent on non-utility and utility activities. Due to changes within the organization (such as AERC & AELP discussed by Mr. Thies), the expected 2015 average percentage to be allocated to non-utility for all officers has increased to approximately 12.2%. Therefore, while there have been no changes to the executive

[26] Union increases are governed by contract terms. Negotiations are currently underway with the current contract expiring on March 25, 2014.
[27] See discussion on acquisition of Alaska Energy and Resources Company (AERC) and Alaska Electric Light & Power (AEL&P) by Mr. Thies at Exhibit No. __(MTT-1T).

officers salaries in this filing, the weighting of utility/non-utility has been updated to be approximately 87.8% utility and 12.2% non-utility.

Ms. Feltes discusses Company executive compensation, providing support for the level of executive compensation included in the Company's filing. The impact of this adjustment on Washington net operating income is a slight decrease of $16,000.

The adjustment in column (3.04), **Pro Forma Employee Benefits**, adjusts for changes in both the Company's pension and medical insurance expense, increasing Washington net operating income by $563,000.

Q. Please describe the pension expense portion of the Employee Benefits adjustment and Washington's share of this expense.

A. As discussed by Ms. Feltes, the Company's pension expense portion of this adjustment is determined in accordance with Accounting Standard Codification 715 (ASC-715), and has decreased on a system basis from approximately $26.6 million for the actual test year costs for the twelve months ended June 30, 2013, to $19.8 million for 2015. The decrease in pension <u>expense</u> ($1.7 million Washington electric) is primarily due to ongoing Company contributions to the Plan (to improve the funded status) and an increase in the discount rate used in calculating the pension expense and liability. Ms. Feltes also discusses cost measures the Company has undertaken to reduce pension expense into the future.

At this time the amounts included in this case are based on the most current available data. Preliminary pension expense is determined by an outside actuarial firm, in accordance with ASC-715, and provided to the Company late in the first quarter of each year. These calculations and assumptions are reviewed by the Company's outside accounting firm annually for reasonableness and comparability to other companies. Due to the timing of this report, additional information may become known during the course of these proceedings that may require a modification to this adjustment.

Q. Please now describe the medical insurance and post-retirement expense portion of the Employee Benefits adjustment and Washington's share of this expense.

A. The Company's medical insurance and post-retirement <u>expense</u> portion of this adjustment ($0.8 million Washington electric) adjusts for the medical-related costs planned for 2015 above the test period. As discussed by Ms. Feltes, net medical insurance and post-retirement expense has increased on a system basis from $30.8 million for the actual test year costs for the twelve months ended June 30, 2013, to $34.1 million for 2015. The increase in 2014 represents medical trend and utilization expectations as well as accounting for Health Care Reform mandates. Furthermore, our aging population within our plan continues to impact our claims experience and retiree utilization and expense continues to be a concern. Ms. Feltes discusses the actions the Company is taking to help mitigate some of these increased costs. In addition, these increases in Medical have been offset by a decrease in ASC715 post-retirement medical expenses. The primary drivers in this decrease are related to the increase in the discount rate and the changes to the retiree medical plan discussed by Ms. Feltes. The net impact of the increases in pension and medical costs is an increase in Washington electric <u>expense</u> of approximately $866,000.

The adjustment in column (3.05), **Pro Forma Insurance**, adjusts actual test period insurance expense related to the utility for general liability, directors and officers ("D&O") liability, and property to reflect the expected 2015 level of insurance, resulting in an increase in expense of $556,000 Washington share.[28] Insurance costs that are properly charged to non-utility operations have been excluded from this adjustment. In addition, Avista has removed a total of 10% of the total Directors' and Officers' insurance expense as ordered in Docket No. UE-090134. This adjustment decreases Washington net operating income by $361,000.

Q. Please briefly explain the causes of the increases in insurance expense.

A. The Company is seeing an increase in each of these insurance categories. General liability insurance is increasing due to primary insurance policy providers seeking increases due to adverse impacts over the last several years from increased claim history and due to suspension by insurance providers of the continuity credit provided in previous years. Property insurance premiums are being driven up by two primary factors: 1) projected increases in asset values for the Company, and 2) increases in the rate per $100 of coverage of these assets caused by weather related catastrophe losses associated with Super Storm Sandy in 2012, and significant losses related to a few refinery explosions in the industry in 2013. Director's & Officer's (D&O) insurance premiums are also expected to increase, driven by a significant reduction in our continuity credit combined with an increase in premium rates.

[28] The increase in insurance expense noted above is net of the offset to reduce D&O insurance expense for the 10% portion removed.

Q. Please continue with your explanation of the pro forma adjustments shown on page 8.

A. The adjustment in column (3.06), **Pro Forma Property Tax**, restates the 2013 level of property tax expense (previously discussed in the Restating Adjustment section above, see Adjustment (2.02) Restate 2013 Property tax), to the 2015 level of expense. 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, 2014, reflecting the 2015 level of expense the Company will experience during the rate period. The effect of this adjustment decreases Washington net operating income by $1,325,000.

Q. With regards to the 2013 level of property tax expense included prior to this pro forma adjustment, what date is used to determine the property value and tax?

A. The tax basis for the 2013 period expense is based on plant balances as of December 31, 2012.

Q. What does this mean for ratemaking purposes and the impact of property tax expense in this case?

A. The restated property tax expense for 2013, prior to this pro forma adjustment, is understated for ratemaking purposes, because it only captures the property taxes on property owned by the Company at December 31, 2012. For ratemaking purposes, this filing must capture the property tax associated with all property that will be assessed property taxes during the rate year. A property tax that captures only property owned on December 31, 2012 will not serve to match costs with benefits.

Q. How has Avista calculated its property tax adjustment in this filing?

A. The Company's pro forma property tax calculation captures all assets owned on December 31, 2014. This adjustment is necessary, because the 2013 level of property tax expense represents an understated estimate of the property taxes associated with the rate year for two reasons. First, the 2013 level of property tax does not include any actual additions to plant for 2013 or 2014. These additions are the basis for the actual expenses the Company will incur in 2015. Second, the methodology used to produce the tax value included in the historical test year violates the matching principle, because it fails to match the costs in the rate year with the benefits derived from the assets owned during the rate year.

Q. Please summarize how Avista has calculated the property tax expense included in this filing.

A. The system tax basis was determined by using the actual tax basis used to compute the 2013 actual property tax expense, which was the net book value of Company owned property as of December 31, 2012. This amount was increased approximately $107 million, to reflect actual plant additions for 2013, net of 2013 actual depreciation expense. In addition, the tax basis was increased by approximately $87 million to reflect 2014 plant additions and depreciation expense. The most current tax rates were applied to this computed tax basis to determine the 2015 property tax expense. The effect of this adjustment decreases Washington net operating income by $1,325,000.

Q. Please continue with your discussion of the pro forma adjustments included on page 8 of Exhibit No. __(EMA-4).

A. The last column on page 8, includes the adjustment in column (3.07), **Pro Forma Information Technology/Services Expense,** 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 Company witness 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 Washington net operating income by $692,000.

Q. Turning to page 9 of Exhibit No. __(EMA-4), what is shown in the first column on that page?

A. The first column on page 9, labeled Pro Forma Sub-Total, reflects total pro forma results of operations and rate base consisting of test period actual results (twelve-months ending June 30, 2013) and the restating and pro forma adjustments explained thus far.

Q. Please briefly explain each of the adjustments included on page 9 of Exhibit No. __(EMA-4).

A. The first adjustment included in column (4.00), **Planned Capital Additions December 2013 EOP**, reflects the additional July through December 2013 capital additions[29] together with the associated accumulated depreciation (A/D) and

[29] For each of the periods July-December 2013, 2014, and 201, distribution-related capital expenditures associated with connecting new customers to the Company's system was excluded. The Pro Forma Cross Check Analysis does not include the increase in revenues from growth in the number of customers from the historical test year to the 2015 rate year and therefore, the growth in plant investment associated with customer growth was also excluded.

accumulated deferred federal income taxes (ADFIT) at a December 2013 EOP basis. This adjustment also includes associated depreciation expense for these July through December 2013 additions. In addition, the plant-in-service at June 30, 2013 end-of-period, was adjusted to a December 31, 2013 EOP basis. Mr. DeFelice describes this adjustment in detail within his testimony. The effect of this component decreases Washington net operating income by $2,422,000 and increases rate base by $33,588,000.

The next adjustment included in column (4.01), **Planned Capital Additions 2014 EOP**, reflects the additional 2014 capital additions[30] together with the associated A/D and ADFIT at a December 31, 2014 EOP basis. This adjustment also includes associated depreciation expense for these 2014 additions. In addition, the plant-in-service at December 31, 2013 end-of-period was adjusted to a December 2014 EOP basis. Mr. DeFelice describes this adjustment in detail within his testimony. The effect of this adjustment decreases Washington net operating income by $3,655,000 and increases rate base by $74,587,000.

Column (4.02), **Planned Capital Additions 2015 AMA**, reflects all 2015 capital additions[31] together with the associated A/D and ADFIT at a 2015 AMA basis. This adjustment includes associated depreciation expense for the 2015 additions. In addition, the plant-in-service at December 31, 2014 was adjusted to a December 31, 2015 AMA basis. Mr. DeFelice also describes this adjustment in detail within his testimony. The effect of this adjustment decreases Washington net operating income by $1,680,000 and

[30] Id.
[31] Id.

increases rate base by $19,440,000.

Column (4.03), labeled **DSM.** As explained by Mr. Ehrbar, one of the reasons Avista is experiencing attrition is due to our success in assisting our customers with electric energy efficiency through our DSM programs. Mr. Ehrbar quantifies how much of Avista's attrition problem is being caused by electric energy savings through DSM, which is included in this component. The effect of this component decreases Washington net operating income by $3,323,000.

As previously discussed, the last column on page 9, labeled "Pro Forma Cross Check Total," reflects the total electric revenue requirement for 2015 of $32,602,000 based on the use of restating and pro forma adjustments from the historical test year to the 2015 rate year. This revenue requirement can be compared or "cross checked" to the revenue requirement determined using the Attrition Study of $32,541,000, shown at the bottom of the second column on page 10 of Exhibit No. __(EMA-4).

Q. Please describe the individual adjustments shown on page 10.

A. The first column on page 10, labeled (4.04), **Reconcile Pro Forma To Attrition,** represents the difference of ($61,000 revenue requirement) between the Pro Forma Cross Check Study and the Attrition Study. This adjustment records the reduction in expense of $438,000, increasing Washington net operating income by $320,000, and additional net rate base of $3,656,000 necessary to equate with the total level of attrition deficiency as determined by the Company's Attrition Study.

The next adjustment in column (4.05), is labeled **Lake Spokane Deferral 3-Year Amortization.** This adjustment reflects the Company's proposed three-year amortization of the deferred costs related to improving dissolved oxygen levels in Lake Spokane, and rate base treatment of the deferred balance recorded in account 182.3, net of deferred FIT, on an AMA basis for the 2015 rate period. Mr. Kinney discusses further the costs incurred by the Company to study the improvement of total dissolved gas downstream of the Long Lake and the outcome of that study.

In Docket No. UE-131576 the Company sought, and received approval of (see Order No. 0l), an Accounting Order to defer the costs related to the improvement of dissolved oxygen levels in Lake Spokane. Order No. 01 authorized the Company to defer and transfer Washington's share of these costs (approximately $871,000) to FERC account 182.3. The Order also approved Avista's proposal for recovery and prudency of these costs to be determined in its next general rate case or in a separate filing.

The Company therefore, is proposing a three-year amortization of this balance starting in 2015 when new rates go into effect from this proceeding, as a reasonable amortization period to reduce the impact on customers, while providing recovery of these costs at a sufficient rate for the Company. The effect of this adjustment decreases Washington net operating income by $184,000 and increases net rate base by 472,000.[32]

The adjustment included in column (4.06) is **O&M Offsets**. As explained by Mr. DeFelice, all of the 2013 (July through December), 2014 and 2015 capital additions were reviewed for any O&M offsets that were expected in the 2015 rate period. Specific

[32] It is the Company's understanding, per Order No. 01 in Docket No. UE-131576**,** that the Company would not seek a carrying charge on the deferred balance. After completion of the Company's revenue requirement in this filing, the Company realized it had inadvertently included a net rate base addition of $472,000 representing the net rate base balance during the 2015 rate period. Correction of this error would reduce the requested revenue requirement by approximately $59,000.

offsets identified were included as a reduction to O&M costs in both the Attrition and Pro Forma Studies, and discussed in Mr. Kinney, Ms. Rosentrater, and Mr. DeFelice's direct testimonies with the capital asset with which the offset relates.[33] The effect of this adjustment on Washington net operating income is an increase of $398,000.

The final pro forma adjustment included in column (4.07) **Revenue Normalization 2014**, includes revenue repricing of the 2014 authorized rates approved on a temporary basis in Docket No. UE-120436). Ms. Knox is sponsoring this adjustment. The effect of this adjustment increases Washington net operating income by $8,724,000.

Q. Please summarize the purpose of the electric Pro Forma Cross Check Study.

A. The Company's electric rate relief for 2015 requested in this case is based on the Company's electric Attrition Study results. The purpose of the electric Pro Forma Cross Check Study is to provide a "cross check" to the reasonableness of the electric Attrition Study as discussed previously in Section III. Attrition Studies. Furthermore, the Pro Forma Cross Check revenue requirement is reconciled to the Attrition Study revenue requirement in order to establish revenue, expenses and rate base numbers that can be used as inputs to the Company's cost of service study prepared by Ms. Knox.

Natural Gas Pro Forma Cross Check Study

[33] As noted within the Attrition Study discussion, upon further review of the Company's filing, the Company realized that the O&M Offset adjustment should have been included as a Pro Forma Cross Check Study adjustment only, and not included as an offset to the Attrition adjusted total.

Q. Would you please explain what is shown on page 1 of Exhibit No._____(EMA-5)?

A. Yes. Exhibit No._____(EMA-5), page 1, shows actual and pro forma natural gas operating results and rate base for the test period for the State of Washington. Column (b) of page 1 of Exhibit No._____(EMA-5) shows twelve-months ending June 30, 2013 actual operating results and components of the average-of-monthly-average rate base as recorded; column (c) is the total of all adjustments to net operating income and rate base; and column (d) is pro forma adjusted results of operations, all under existing rates. Column (e) shows the revenue increase required which would allow the Company to earn a 7.71% rate of return. Column (f) reflects total pro forma natural gas operating results with the requested increase of $12,135,000.

Q. Would you please explain page 2 of Exhibit No._____(EMA-5)?

A. Yes. Page 2 shows the calculation of the $12,135,000 revenue requirement at the requested 7.71% rate of return based on the natural gas Pro Forma Cross Check Study.

Q. What does page 3 of Exhibit No._____(EMA-5) show?

A. Page 3 shows the proposed Cost of Capital and Capital Structure utilized by the Company in this case, and the weighted average cost of capital calculation of 7.71%, as previously explained in Section III. Attrition Studies.

Q. Please explain page 4 of Exhibit No._____(EMA-5)?

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 35%.

Q. Now turning to pages 5 through 10 of your Exhibit No._____(EMA-5), would you please explain what those pages show?

A. Yes. Page 5 begins with actual operating results and rate base for the twelve-months-ending June 30, 2013 test period 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 (2.15) on page 7. Individual pro forma adjustments are shown on page 8 in columns (3.00) though (3.05). The first column on page 9, labeled "Pro Forma Sub-total" is the subtotal of the previous columns (1.00) through (3.07).

Columns (4.00) through (4.02), on page 9 of Exhibit No._____(EMA-5), represent additional pro forma adjustments related to capital additions for July through December 2013, 2015 and 2015. The last column on page 9, labeled "Pro Forma Cross Check Total," reflects the total natural gas revenue requirement for 2015 of $13,935,000 based on the use of restating and pro forma adjustments from the historical test year to the 2015 rate year.

This revenue requirement can be compared as a "cross check" to the revenue requirement determined using the Attrition Study of $13,506, which is shown at the bottom of the second column on page 10 of Exhibit No. __(EMA-5).

Column (4.03) on page 10 represents the difference of ($429,000) between the Pro Forma Cross Check Study and the Attrition Study.

An additional column, shown on page 10 of Exhibit No._____(EMA-4), (4.04) is a final pro forma adjustment to restate the attrition-adjusted sub-total for known offsets believed to be outside the attrition-adjusted revenue requirement proposed in this case.[34] The final pro forma adjustment (4.05) reduces the revenue requirement for current 2014 revenues approved on a temporary basis, leaving the final column "Final Revenue Requirement Total" representing the proposed operating results and rate base for the test period, and the necessary incremental 2015 rate relief.

The Pro Forma Cross Check revenue requirement is reconciled to the Attrition Study revenue requirement in order to establish revenue, expenses and rate base numbers that can be used as inputs to the Company's cost of service study prepared by Company witness Mr. Miller.

Each of the Commission Basis, restating and pro forma adjustments are discussed in the testimony that follows, and the Company has also provided workpapers, both in hard copy and electronic formats, outlining additional details related to each of the adjustment.

Standard Commission Basis and Restating Adjustments

Q. Would you please explain each of these adjustments, the reason for the adjustment and its effect on test period State of Washington net operating income and/or rate base?

[34] However, after completing our review of this case the Company realized that the O&M Offset adjustment should have been included within the Pro Forma Cross Check Study amount, and not included as an offset to the Attrition adjusted total.

A. Yes, but before I begin, I will note the **Results of Operations** column (1.00), reflects the Company's actual operating results and total net rate base experienced by the Company for the twelve-month period ending June, 30 2013 on an average-of-monthly-average (AMA) basis.[35] Columns following the Results of Operations column (1.00) 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 amounts reflected in the actual June 30, 2013 results.

Q. Please continue with your explanation of each adjustment and its effect on test period net operating income and/or rate base.

A. The first adjustment, column (1.01) on page 5, entitled **Deferred FIT Rate Base**, adjusts the DFIT rate base balance included in the Results of Operations column (1.00) to the corrected DFIT balance, as shown within my workpapers provided with the Company's filing. This adjustment to rate base is necessary to reflect various revisions related to the final 2012 tax return filed in 2013 and tax return audit adjustments. Accumulated DFIT reflects the deferred tax balances arising from accelerated tax depreciation (Accelerated Cost Recovery System, or ACRS, and Modified Accelerated

[35] This column, reflects an actual results of operations rate of return of 5.34% as shown on page 1 of Exhibit No. __(EMA-5), at line 48. This 5.34% excludes the Voluntary Severance Incentive Program (VSIP) costs, however, as non-recurring and was excluded from recovery from customers in 2013 and 2014. However, the benefits of the VSIP initiative are reflected in the electric and natural gas operating results in this proceeding as the labor expense of those individuals who participated in the VSIP initiative were excluded from the 2015 pro forma level of labor expense. Although the VSIP costs were excluded from recovery from customers and the operations column (1.00), it is appropriate to include the VSIP costs in the calculation of actual operating results at twelve-months-period-ending June 30, 2013, resulting in an actual ROR of 5.03%, as shown on page 1 of Exhibit No. __(EMA-5), at line 49.

Cost Recovery, or MACRS) and bond refinancing premiums. These amounts are reflected on the average-of-monthly-average balance basis. The effect on Washington rate base for this adjustment is a reduction of $883,000. A decrease to Washington net operating income of $9,000 is due to the Federal income tax (FIT) expense on the restated level of interest on the change in rate base.[36]

The adjustment in column (1.02), **Deferred Debits and Credits,** is a consolidation of certain commission basis or restating other rate base adjustments and their net operating income (NOI) impact as described in the Electric Pro Forma section above. The rate base amount for each of the deferred debits and credits adjustments discussed below are accurately reflected in the natural gas results of operations reports and the Results of Operations column (1.00), and therefore no restating rate base adjustment is necessary. The net impact on a consolidated basis of this adjustment on Washington natural gas net operating income (NOI) is a reduction of $1,000.

For consistency with prior rate case filings, a description of each previously separated adjustment is included below.

- **Customer Advances** 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. The reduction to rate base per results of operations is accurately reflected at approximately $13,000; therefore no adjustment is necessary to rate base.
- **Customer Deposits** reduces natural gas rate base by the average-of-monthly-averages of customer deposits held by the Company, as ordered by this

[36] 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 adjustment can be seen on Line 28 of Exhibit No. __(EMA-3). As discussed later in my testimony, the "Restate Debt Interest" adjustment restates debt interest using the Company's pro forma weighted average cost of debt, as outlined in the testimony and exhibits of Mr. Thies, 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.

Commission in Docket UE-090135. The reduction to rate base per results of operations is accurately reflected at approximately $449,000; 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 0.14%. The effect on Washington operating income is a decrease of $1,000.

Q. Please continue describing the remaining adjustments on page 5.

A. The adjustment in column (1.03), **Working Capital,** reflects the natural gas working capital balance for the twelve-month period ending June 30, 2013 on an AMA basis, based on the ISWC methodology, as explained further in the Electric Pro Forma Section above.

In the previous natural gas GRC, Docket No. UG-120437, the Company had not included a natural gas working capital adjustment in order to reduce the rate relief impact on customers and minimize the issues in that case, although the Company believed it was entirely appropriate to include as a rate base item. However, the natural gas working capital requirement continues to impact the natural gas operations, and exclusion of increases the rate lag experienced in the natural gas Washington jurisdiction. As can be seen from the proposed balance, the amount of natural gas working capital of $9.1 million is too significant to continue to exclude from the Company's rate base requested in its natural gas general rate case. The Company therefore proposes adjustment (1.03), resulting in an increase to Washington rate base of $9,100,000 and an increase to Washington net operating income of $88,000, due to the FIT expense on the restated level of interest on the change in rate base.

The adjustment in column (2.01), **Eliminate B & O Taxes**, eliminates the revenues and expenses associated with local business and occupation taxes, which the

Company passes through to 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 net operating income by $3,000.

The adjustment in column (2.02), **Restate 2013 Property Tax,** restates the accrued property tax during the test period to actual property tax paid during 2013. Property tax expense for 2013 was based on actual plant balances as of December 31, 2012. The effect of this adjustment is to decrease Washington net operating income by $404,000. Please see pro forma discussion below, Adjustment (3.04) Pro Forma Property Tax, for additional amounts pro formed, increasing the property tax expense included in the Company's filing to the 2015 rate year level of expense.

The adjustment in column (2.03), **Uncollectible Expense**, restates the accrued expense to the actual level of net write-offs for the test period. The effect of this adjustment is to increase Washington net operating income by $174,000.

Q. Please turn to page 6 and explain the first column shown there, and the adjustments that follow.

A. The first adjustment on page 6 in column (2.04), entitled **Regulatory Expense Adjustment**, restates recorded regulatory expense for the twelve-month period ended June 30, 2013 to reflect the UTC assessment rates applied to revenues for the test period. The effect of this adjustment is to increase Washington net operating income by $16,000.

The adjustment in column (2.05), entitled **Injuries and Damages**, is a restating adjustment that replaces the accrual with actuals to obtain the 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 increases Washington net operating income by $40,000.

The adjustment in column (2.06), entitled **FIT/DFIT Expense**, adjusts the FIT calculated at 35% within Results of Operations by removing the effect of certain Schedule M items. This adjustment also reflects the proper level of deferred tax expense for the test period, all based upon a Federal tax rate of 35%. The effect of this adjustment increases current FIT expense by $44,000, and decreases deferred tax expense by $44,000, resulting in a net $0 change to Washington net operating income.

The adjustment in column (2.07), **Office Space Charges to Subs**, removes a portion of the office space costs (including, but not limited to 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.) using 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 and consistent with previous

Company general rate cases. The effect of this adjustment is to increase Washington net operating income by $5,000.

The adjustment in column (2.08), **Restate Excise Taxes**, removes the effect of a one-month lag between collection and payment of taxes. The effect of this adjustment is a net $0 impact to Washington net operating income.

The adjustment in column (2.09), **Net Gains/Losses**, reflects a ten-year amortization of net gains realized from the sale of real property disposed of between 2003 and 2013. This restating adjustment is made as a result of the Commission's Order in Docket No. UG-050483 and consistent with previous Company general rate cases. The effect of this adjustment is to increase Washington net operating income by $1,000.

The adjustment in column (2.10), entitled **2013 Revenue Normalization & Gas Cost Adjustment**, is an adjustment taking into account known and measurable changes that include revenue normalization (including the 2013 authorized rates approved in Docket No. UG-120437), which reprices customer usage for 2013 increased rates, as well as weather normalization and an unbilled revenue calculation. Associated natural gas costs are replaced with natural gas costs computed using normalized volumes at the currently effective "weighted average cost of gas," or WACOG rates. Revenues associated with the temporary Gas Rate Adjustment Schedule 155 and Schedule 191 Tariff Rider are excluded from pro forma revenues, and the related amortization expense is eliminated as well.[37] Company witness Mr. Miller is sponsoring this adjustment. The

[37] The impact of this adjustment is also included in the Company's natural gas Attrition Study. See column [D], page 4 of Exhibit No. __(EMA-3).

effect of this particular adjustment is to increase Washington net operating income by $2,395,000.

Q. Please turn to page 7 and explain the adjustments shown there.

A. The first adjustment on page 7 in column (2.11), **Restate Atmospheric Testing**, adjusts the test period expense for Atmospheric Corrosion expense. This 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 is on a three-year rotation between the Company's jurisdictions (Washington, Idaho, and Oregon) and is therefore, coded directly to Washington operations for the year in which the inspection occurs.

The atmospheric testing for 2012, which occurred in Washington at a cost of approximately $715,000, was directly charged to Washington and included in test period results in this case. For 2015 the atmospheric testing inspection program will occur in Washington at an estimated cost of approximately $789,000. Therefore, this adjustment includes 1/3 or $163,000 of the 2015 level of expense for Washington's natural gas operations (resulting in a reduction to test period results).

To be consistent in all three of Avista's natural gas jurisdictions, the Company has included a three-year amortization for each of its jurisdictional (WA, ID, OR) general rate case filings. This method is consistent with the approach used in the Company's past two WA GRC filings, Docket Nos. UG-110877 and UG-120437. The Company has received approval of this accounting treatment in its Oregon jurisdiction. However, due to the black-box nature of the settlements approved in both Avista's Washington and Idaho jurisdictions in the previous 2011 and 2012 rate cases, the Company is requesting this treatment again in this filing, and in the Company's next Idaho general rate case as well, so the Company remains whole on an annual basis. This adjustment increases Washington net operating income by $294,000.

The adjustment in column (2.12), **Miscellaneous Restating Adjustments**, removes a number of non-operating or non-utility expenses associated with dues and donations, etc., included in error in the test period actual results, and removes or restates other expenses incorrectly charged between service and or jurisdiction totaling approximately $21,000. The Company also removed 50% of director meeting expenses, as ordered in Docket No. UE-090135, and restates director fee expenses to reflect a 90% Utility / 10% non-utility split, totaling approximately $5,000. The total effect of this adjustment is to increase Washington net operating income by $17,000.

The adjustment in column (2.13), **Restating Incentive Adjustment,** restates actual incentives included in the Company's test period ending June 30, 2013, reducing overall expense by approximately $860,000. As explained further in the Electric Pro Forma Section above, this reduction in incentive expense is, in part, due to a change in Company policy regarding incentive allocation between Capital and O&M, and reduced to reflect a six-year average of payout percentages. The effect of this adjustment increases Washington net operating income by $559,000.

The adjustment in column (2.14), **Restate Debt Interest**, restates debt interest using the Company's pro forma weighted average cost of debt, as outlined in the testimony and exhibits of Mr. Thies, 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 $211,000.

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 in each individual rate base adjustment described elsewhere in this testimony.

The last restating adjustment shown on page 7 is included in column (2.15), **Restating June 30, 2013 Capital EOP.** This adjustment restates plant additions included in the test year on a June 30, 2013 AMA basis to an end of period basis, together with the associated accumulated depreciation and deferred federal income taxes at a June 30, 2013 end of period basis, as described further by Mr. DeFelice. This adjustment also includes the annual level of associated depreciation expense on all plant-in-service at June 30, 2013.[38] The effect of this adjustment on Washington net operating income is a decrease of $628,000. The effect on Washington rate base is an increase of $4,955,000.

The last column on page 7, entitled **Restated Total**, subtotals all the preceding columns (1.00) through column (2.15). These totals represent actual operating results and rate base plus the standard normalizing adjustments that the Company includes in its annual Commission Basis reports. However, the Restated Total column does not

[38] The impact of this adjustment is also included in the Company's natural gas Attrition Study. See column [C], page 4 of Exhibit No. __(EMA-3).

represent June 30, 2013 test period results of operation on a normalized commission basis. Differences between certain restating adjustments included in normalized Commission Basis Reports (CBRs) versus those included here, include but not limited to, inclusion of 2013 annualized revenues (described in adjustment 2.10 Revenue Normalization & Gas Cost Adjustment above); inclusion of debt interest restated based on the Company's proposed weighted cost of debt (described in adjustment 2.14 Restate Debt Interest above) and inclusion of net plant investment on an end-of-period basis (described in adjustment 2.15 Restating June 30, 2013 Capital EOP above).[39] Each of the adjustments noted above have been included consistent with past general rate case filings by the Company. For Commission Basis Report results of operations for test period ending June 30, 2013 (resulting in a 5.79% rate of return), please see Exhibit No. __(EMA-3), page 5, line 48.

<u>Pro Forma Adjustments</u>

Q. Please explain each of the pro forma adjustments shown on page 8.

A. The adjustment in column (3.00), **Pro Forma Labor-Non-Exec**, reflects known and measurable changes to test period union and non-union wages and salaries, excluding executive salaries, which are handled separately in adjustment (3.01) (as explained in the Electric Pro Forma Section above.) The methodology behind this adjustment is consistent with that used in the Company's previous Docket No. UE-

[39] The restated total also includes additional restatements, such as inclusion of a natural gas working capital adjustment (including a proposed change to include pension related regulatory assets and liabilities), and reductions to incentive expense recognizing portions capitalized starting 1/1/2013 and to reflect a 6-year average pay-out percentage for the level of expense included.

120437. The effect of this adjustment on Washington net operating income is a decrease of $304,000.

The adjustment in column (3.01), **Pro Forma Labor-Executive**, reflects known and measurable changes to reflect an annualized 2013 level of allocated executive officer salaries. However, the Company has included utility and non-utility allocation percentages planned for 2015. No additional increases in executive labor for 2014 or 2015 planned expenses have been included in this filing. This adjustment is further explained in the Electric Pro Forma Section above. The effect of this adjustment on Washington net operating income is a slight increase of $5,000. It otherwise contains no increase in executive officer base pay.

The adjustment in column (3.02), **Pro Forma Employee Benefits**, adjusts for a net reduction in Company pension and medical insurance expense (as explained in the Electric Pro Forma Section above) and increases Washington net operating income by $156,000.

The adjustment in Column (3.03), **Pro Forma Insurance**, adjusts actual test period insurance expense related to the Utility for general liability, D&O liability, and property to reflect the expected 2015 level of insurance, resulting in an increase in expense of $149,000[40] (as explained in the Electric Pro Forma Section above). This adjustment decreases Washington net operating income by $97,000.

The adjustment in column (3.04), Pro Forma **Property Tax**, restates the 2013

[40] The increase in insurance expense noted above is net of the offset to reduce D&O insurance expense for the 10% portion removed.

level of property tax expense (previously discussed in the natural gas restating adjustment section above, see Adjustment (2.02) Restate 2013 Property tax), to the 2015 level of expense. (For further explanation of the pro forma adjustment, see (3.06) Pro Forma Property Tax adjustment in the Electric Pro Forma Section above.) 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, 2014, reflecting the 2015 level of expense the Company will experience during the rate period. The effect of this particular adjustment is to decrease Washington net operating income by $240,000.

The last pro forma adjustment on page 8, includes the adjustment in column (3.05), **Pro Forma Information Technology/Services Expense,** which includes the incremental costs associated with software development, application licenses, maintenance fees, and technical support for a range of information services programs. Mr. Kensok discusses these incremental expenditures in more detail within his testimony. The effect of this adjustment decreases Washington net operating income by $186,000.

Q. Turning to page 9 of Exhibit No. __(EMA-5), what is shown in the first column on that page?

A. The first column on page 9, labeled Pro Forma Sub-Total, reflects total pro forma results of operations and rate base consisting of test period actual results (twelve-months ending June 30, 2013) and the restating and pro forma adjustments explained thus far.

Q. Please briefly explain each of the adjustments included on page 9 of

Exhibit No. __(EMA-5).

A. The first adjustment included in column (4.00), **Planned Capital Additions December 2013 EOP**, reflects the additional July through December 2013 capital additions[41] together with the associated accumulated depreciation (A/D) and accumulated deferred federal income taxes (ADFIT) at a December 2013 EOP basis. This adjustment also includes associated depreciation expense for these July through December 2013 additions. In addition, the plant-in-service at June 30, 2013 end-of-period, was adjusted to a December 31, 2013 EOP basis. Mr. DeFelice describes this adjustment in detail within his testimony. The effect of this component decreases Washington net operating income by $652,000 and increases rate base by $11,295,000.

The next adjustment included in column (4.01), **Planned Capital Additions 2014 EOP**, reflects the additional 2014 capital additions[42] together with the associated A/D and ADFIT at a December 31, 2014 EOP basis. This adjustment also includes associated depreciation expense for these 2014 additions. In addition, the plant-in-service at December 31, 2013 end-of-period was adjusted to a December 2014 EOP basis. Mr. DeFelice describes this adjustment in detail within his testimony. The effect of this component decreases Washington net operating income by $942,000 and increases rate base by $15,436,000.

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[41] For each of the periods July-December 2013, 2014, and 2015, distribution-related capital expenditures associated with connecting new customers to the Company's system was excluded. The Pro Forma Cross Check Analysis does not include the increase in revenues from growth in the number of customers from the historical test year to the 2015 rate year and therefore, the growth in plant investment associated with customer growth was also excluded.

[42] Id.

Column (4.02), **Planned Capital Additions 2015 AMA**, reflects all 2015 capital additions[43] together with the associated A/D and ADFIT at a 2015 AMA basis. This adjustment includes associated depreciation expense for the 2015 additions. In addition, the plant-in-service at December 31, 2014 was adjusted to a December 31, 2015 AMA basis. Mr. DeFelice also describes this adjustment in detail within his testimony. The effect of this component decreases Washington net operating income by $430,000 and increases rate base by $3,352,000.

As previously discussed, the last column on page 9, labeled "Pro Forma Cross Check Total," reflects the total natural gas revenue requirement for 2015 of $13,935,000 based on the use of restating and pro forma adjustments from the historical test year to the 2015 rate year. This revenue requirement can be compared or "cross checked" to the revenue requirement determined using the Attrition Study of $13,506,000, shown at the bottom of the second column on page 10 of Exhibit No. __(EMA-4).

Q. Please describe the individual adjustments shown on page 10.

A. The first column on page 10, labeled (4.03), **Reconcile Pro Forma To Attrition,** represents the difference of ($429,000 revenue requirement) between the Pro Forma Cross Check Study and the Attrition Study. This adjustment records the increase in expense of $614,000, decreasing Washington net operating income by $494,000, and the reduction to net rate base of $9,867,000 necessary to equate with the total level of attrition deficiency as determined by the Company's Attrition Study.

[43] Id.

The next adjustment in column (4.04) is **O&M Offsets**. As explained by Mr. DeFelice, all of the 2013 (July through December), 2014 and 2015 capital additions were reviewed for any O&M offsets that were expected in the 2015 rate period. Specific offsets identified were included as a reduction to O&M costs in both the Attrition and Pro Forma Studies, and discussed in Mr. DeFelice's direct testimony with the capital asset with which the offset relates.[44] The effect of this adjustment on Washington net operating income is an increase of $8,000.

The final pro forma adjustment included in column **(4.05) Revenue Normalization 2014**, includes revenue repricing of the 2014 authorized rates approved on a temporary basis in Docket No. UE-120437). Mr. Miller is sponsoring this adjustment. The effect of this adjustment increases Washington net operating income by $843,000.

Q. Please summarize the purpose of the natural gas Pro Forma Cross Check Study.

A. The Company's natural gas rate relief for 2015 requested in this case is based on the Company's natural gas Attrition Study results. The purpose of the natural gas Pro Forma Cross Check Study is to provide a "cross check" to the reasonableness of the natural gas Attrition Study as discussed previously in Section III. Attrition Studies. Furthermore, the Pro Forma Cross Check revenue requirement is reconciled to the Attrition Study revenue requirement in order to establish revenue, expenses and rate base

[44] As noted within the Attrition Study discussion, upon further review of the Company's filing, the Company realized that the O&M Offset adjustment should have been included as a Pro Forma Cross Check Study adjustment only, and not included as an offset to the Attrition adjusted total.

numbers that can be used as inputs to the Company's cost of service study prepared by Mr. Miller.

V. 2016 INFORMATION

Q. Throughout this testimony you discuss and support the need for rate relief in 2015, determined through the Company's electric and natural gas Attrition Studies, and "cross checked" with the Company's electric and natural gas Pro Forma Studies. Do you expect a continued increase in operating expenses and net plant investment, and the need for additional rate relief beyond the 2015 level of costs requested in this filing?

A. Yes, I do. The following discussion related to 2016 incremental revenue requirement is based on extending the Company's electric and natural gas Attrition Studies an additional year to 2016. This additional discussion is included here for informational purposes only, and has not been included in the Company's request for rate relief. Supporting workpapers for 2016 based on the Company's electric and natural gas Attrition Study analysis, as well as pro forma adjustment workpapers providing a "cross check" to the Attrition Study analysis, also accompany the Company's filed case.

Q. Please explain the results of the Company's electric and natural gas Attrition Study analysis for the period 2016.

A. The results of the electric and natural gas Attrition Study analysis for 2016 builds on the Attrition Study analysis completed and previously described earlier in my testimony in Section III. Attrition Studies, for the period 2015. The Company used the same compound growth rates (period 2007-2012) as previously described in Section III.

Attrition Studies for 2015, adjusted for 2016 pro forma power supply, and updated revenues to include 2016 expected revenues. The results for the 2016 rate year show a need for revenue increases of $20,158,000 million for electric (or 4.04%), and $3,647,000 million for natural gas (or 2.25%). (See column (h) of Exhibit No. __(EMA-6), pages 1 and 9, respectively.)[45]

As a "cross check" on the reasonableness of the calculated revenue need based on the electric and natural gas 2016 Attrition Study analysis, the Company also looked at additional expenditures planned for the Utility in 2016. For this "cross check" the Company reviewed incremental increases in major cost categories, such as new plant investment, expected increases in net power supply and labor costs, and the impact of DSM on 2016 revenues.

For example, as mentioned in Mr. Thies' testimony, Avista's plans call for significant capital expenditure requirements of approximately $1.7 billion on a system basis over the next five year period ending December 31, 2018. For the 2015 rate relief requested, Washington net plant balances include changes in net rate base through December 2015 on an AMA basis. As described earlier in my testimony, net plant investment represents the main driver of the 2015 rate relief requested in this case over that currently in base rates. With the continued level of capital spend in net plant investment planned on a go-forward basis, net plant investment is expected to continue to

[45] The total 2016 electric and natural gas Attrition Study amounts were $52,698,000 electric and $17,153,000 for natural gas, shown on page 3 and 11, respectively, of Exhibit No. __(EMA-6). After reflecting the "After Attrition Adjustments," the 2014 Temporary Rate Increase, and 2015 Revenue Requirement amounts requested in this filing and previously discussed, the remaining balance is the incremental 2016 rate relief necessary to earn the 7.71% ROR proposed in this filing.

be the driver in the 2016 rate period. The incremental revenue needed in 2016 related solely to these capital additions is approximately $15.2 million electric and $3.05 million for natural gas. (See Mr. DeFelice testimony and exhibits for information related to the 016 capital additions.)

Q. Please discuss the 2016 incremental expenses reviewed to determine the 2016 pro forma revenue short-fall used as a "cross check" to the Attrition Study balances noted above.

The Company included increases in salaries above that included in the 2015 rate year, based on a conservative 2.5% adjustment for increases expected as of March 1, 2016. The impact of this adjustment is an incremental increase in 2016 expense of approximately $1.0 million electric and $0.3 million natural gas.

Additionally, for electric only, the Company also examined the pro forma power supply net expenses for 2016 and the impact of DSM on 2016 revenues. The impact of these adjustments is an incremental increase in 2016 expense of approximately $0.7 million related to increased power supply net expense and $1.9 million related to the impact of DSM.

Prior to consideration of any other incremental expenses the Company will experience in 2016, the net of the cost categories discussed above, result in a 2016 incremental revenue need of approximately $18.8 million electric and $3.3 million natural gas. A table summarizing the Attrition Study revenue requirement versus the Pro Forma Cross Check using specific cost categories identified above is provided in Table No. 1 below.

Table No. 1

2016 ATTRITION VERSUS 2016 PRO FORMA COSS CHECK
REVENUE REQUIREMENT SUMMARY

	Electric	Natural Gas
2016 Attrition Study Adjusted Balances	$ 52,698	$ 17,153
Reduced For:		
After Attrition Adjustments	(287)	(13)
2014 Temporary Rate Increase	(14,054)	(1,358)
2015 Revenue Requirement Requested Per Filing	(18,201)	(12,135)
2016 Incremental Revenue Requirement - Per Attrition	$ 20,158	$ 3,647
2016 Pro Forma Cross Check Balances		
Incremental Pro Forma Adjsutments:		
Pro Forma 2016 Capital (AMA Basis)	$ 15,183	$ 3,045
Pro Forma 2016 Non-Union Wage Increase	$ 999	$ 276
Pro Forma 2016 Power Supply	$ 723	$ -
2016 DSM	$ 1,870	$ -
2016 Incremental Revenue Requirement - Per Pro Forma Cross Check Adjustments Examined	$ 18,775	$ 3,321

VI. COMPLIANCE WITH PAST COMMISSION ORDERS

Tracking of Washington General Rate Case Expenses

Q. Order No. 6, in Docket Nos. UE-110876 and UG-110877, required Avista to begin tracking its Washington general rate case expenses beginning in 2012. Has the Company fulfilled these requirements?

A. Yes. Effective January 1, 2012, Avista agreed to begin separately accounting for all internal and external costs related to preparation, filing, and litigation of Washington general rate cases (GRCs), including but not limited to internal labor costs, administrative and production costs, and costs of outside services.

Costs associated with internal and external costs related to preparation and filing of the Washington electric and natural gas rate cases filed in 2012 totaled $1.54 million, comprising of approximately $1.28 million of internal labor and benefit costs, $223,000 in outside consulting costs[46], and $38,000 for all other costs, such as travel, administrative and production costs. Washington's electric share of these costs totaled approximately $1.2 million, whereas Washington natural gas totaled $340,000.

Electric and natural gas GRC related costs included in the Company's test period (July 1, 2012 through June 30, 2013) and included in this filing, total approximately $500,000 for electric and $155,000 for natural gas. No additional GRC costs were pro formed in this case.

Internal Audit of Avista Utility Expenditures

Q. Order No. 7, approving the Settlement Stipulation in Docket Nos. UE-100467 and UG-100468, required Avista to perform an internal audit of its accounting practices. Has the Company fulfilled these requirements?

A. Yes. The Settlement Stipulation approved by the Commission in Docket Nos. UE-100467 and UE-100468 ordered Avista to perform an annual internal audit for accounting practices in each of the three years following the issuance of that Final Order dated November 19, 2010 (equivalent to the calendar years 2010 through 2013), and to provide a report regarding the results of such audit. In addition to the results of its annual audits, the Company is to provide all internal and external costs associated with performing the audits and preparing the reports. [47]

[46] Approximately $165,000 of the total $223,000 of outside service costs related to the Washington Electric Attrition Study included in the Company's 2012 GRC, Docket No. UE-120436. The remaining outside service costs (or $58,000) related to the Company's Cost of Capital consulting witness Dr. Avera.

[47] Order No. 6, in Docket Nos. UE-110876 and UG-110877 reiterated these requirements at page 12, Paragraph 15.

The Company has completed such audits for the periods 2010 through 2012, with each of these reports provided to all parties.[48] The Company provided a copy of its last report, the 2012 Accounting Practices Audit, to all parties on May 20, 2013. The cost of the 2012 audit was approximately $49,000 in internal labor and benefit costs. The 2013 Accounting Practices Audit report is scheduled to be complete in May 2014, at which time the report and the costs will be provided to all parties.

<u>Tracking of Aldyl-A Natural Gas Pipeline Replacement Program Projects</u>

Q. Order No. 9, approving the Settlement Stipulation in Docket Nos. UE-120436 and UG-120437, required Avista to begin tracking separately, on January 1, 2013, all projects associated with its Aldyl-A natural gas pipeline replacement program. Has the Company fulfilled these requirements?

A. Yes. Beginning January 1, 2013 the Company began tracking through separate projects its Aldyl-A natural gas pipeline replacement program projects and will make this information available upon request to the Commission.

<u>Cost Assignment & Allocation Methodologies</u>

Q. Order No. 9, approving the Settlement Stipulation in Docket Nos. UE-120436 and UG-120437, required Avista to provide additional information regarding its cost[49] assignment and allocation methodologies in its next general rate

[48] The Company provided its 2010 Accounting Practices Audit report and costs within its 2011 GRC filing in Docket Nos. UE-110876 and UG-110877. (See Exhibits Nos. __(EMA-1T) and __(EMA-5).) The Company provided its 2011 Accounting Practices Audit report and costs within its 2012 GRC filing in Docket Nos. UE-120436 and UG-120437. (See Exhibits Nos. __(EMA-1T) and __(EMA-4).)

[49] The Company records revenues, expenses and net plant investment in common accounts that must be allocated to services and jurisdictions. The same allocation process and methodologies are used for all of these accounts. The Company will refer to these revenues, expenses and net plant investment as "costs" throughout this document.

case. Has the Company fulfilled these requirements?

A. Yes. In Paragraph 17 of the Multiparty Settlement Stipulation in Dockets UE-120436 and UG-120437, the settling parties agreed that Avista, in its next general rate case, would provide justification for the service and jurisdictional cost allocation methodologies that it employs. The Company met with several members of the WUTC Staff on December 2, 2013, to provide an overview of Avista's operations and accounting practices, including an overview of its allocation processes and methodologies. The allocation presentation used by the Company at this meeting is provided as Exhibit No. ___ (EMA-7). The testimony that follows describes Avista's cost allocation procedures and why we believe the method used by Avista produces a reasonable allocation of costs.

Q. Would you please describe the utility services provided by the Company and identify the jurisdictions within which the utility services are provided?

A. Yes. The Company provides electric service in two retail jurisdictions[50]: Washington (WA) and Idaho (ID), and natural gas service in three retail jurisdictions: Washington, Idaho and Oregon (OR).

Retail natural gas service provided in eastern Washington and northern Idaho is accounted for separately as the WA/ID natural gas service, or as the North natural gas service. Natural gas service in central and southwest Oregon and is accounted for separately as our Oregon jurisdiction, or the South natural gas service.

Q. How does the Company assign costs by service and jurisdiction?

[50] Avista serves approximately 25 retail electric customers in Montana.

A. Whenever possible, the Company directly assigns its revenues, operating costs and net plant investment to services and jurisdictions. For costs not directly assigned, the Company uses an allocation process using allocation factors that are derived from directly assigned costs which are updated annually. The costs that are not directly assigned are referred to as "common" costs.

For example, Avista's main headquarters in Spokane supports all services and jurisdictions, therefore the operating costs, depreciation expense and net book value of the building is allocated to all services and jurisdictions using allocation factors.

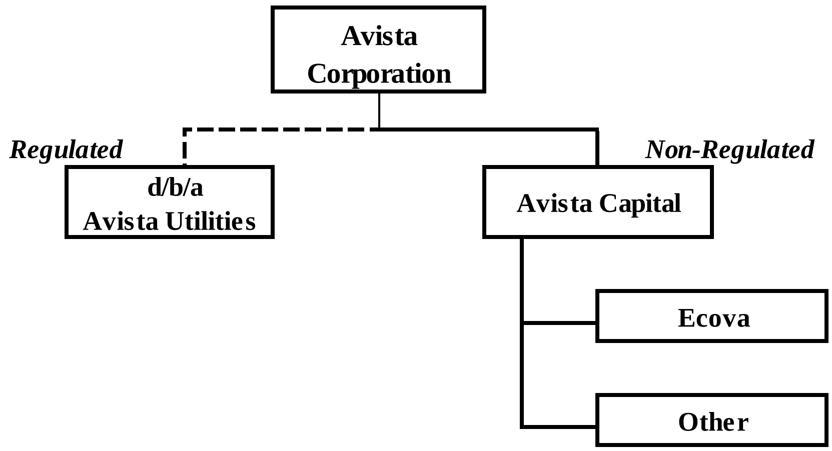
Q. Please explain how the Company accounts for these "common" costs that must be allocated.

A. The Company uses service codes (electric, natural gas and common) and jurisdiction codes (state and common) on all accounting transactions to indicate where costs should be recorded (either directly assigned or where a common cost should be allocated). Both service codes and jurisdiction codes consist of two-digit alpha codes, described further below. The assignments and allocations are used for internal, financial and regulatory reporting and for ratemaking purposes.

Q. Are costs also allocated to non-utility operations or subsidiary companies of Avista Corp.?

A. Instead of being allocated, certain costs are directly assigned to non-utility operations or subsidiaries. Avista Utilities is the regulated operating division of Avista Corp. A current organization chart for Avista Corp. is provided in Illustration No. 3 below.

Illustration No. 3



Certain officers and general office employees of Avista spend time on corporate service support, such as accounting, federal income tax filing, planning, or incur costs for supplies, postage, legal, graphic services, etc. for subsidiaries. Their time and costs are directly charged to suspense accounts and then billed to the subsidiary or directly charged to non-utility FERC accounts. Therefore, there is no need to allocate costs to subsidiaries or non-utility accounts as part of the allocation procedures described below, because they are all directly assigned.

An example of the Company's process for recording subsidiary-related costs is provided in Table No. 2 below.

Table No. 2

Detail of Directors' Fees
For Twelve Months Ended June 30, 2013
($000's)

Total Directors' Fees		$ 1,531
Less: Subsidiary Directors' Fees Charged to FERC 417/186		44
Avista Corp. Directors' Fees		1,488
Less: 10% Charged to Non-utility (FERC 417)		148
Utility Directors' Fees - System		$ 1,340
Allocation of Utility Directors' Fees by Service Using Factor 7:		
Electric	72.346%	$ 969
Natural Gas North	19.401%	260
Natural Gas South (Oregon)	8.253%	111
Total	100.000%	$ 1,340
Allocation of ELECTRIC Utility Directors' Fees by Jurisdiction Using Factor 4:		
Washington Electric	67.000%	$ 649
Idaho Electric	33.000%	320
Total	100.000%	$ 969
Allocation of NATURAL GAS NORTH Utility Directors' Fees by Jurisdiction Using Factor 4:		
Washington Natural Gas	70.603%	$ 184
Idaho Natural Gas	29.397%	76
Total	100.000%	$ 260

Table No. 2 shows that a total of $1.53 million of directors' fees was paid during the twelve months ended June 30, 2013. Of this amount, $44,000 was direct charged to either a subsidiary receivable or to a non-utility FERC account related to Ecova's Board of Director fees. In addition, of the $1.53 million of Avista Corp. Board of Director Fees, $148,000 was directly charged to a non-utility FERC account related to subsidiary operations.[51] The remaining $1.34 million that was charged to the utility is allocated by service and jurisdiction.

Q. Do you believe the allocation methodology used today by the Company is appropriate for allocating common costs?

A. Yes, I do. When the Company designed the allocation methodology that is being used today, the specific objectives identified were as follows:

a) The method must be acceptable to all regulators to prevent any stranded costs or investment,

b) The number of cost allocation methods should be minimized,

c) The method needs to be simple,

d) The method needs to have a sound, rational basis,

e) Allocations under the method should be automated, and

f) The method needs to produce reasonable results.

These objectives are still relevant today. The Company believes the methodology continues to meet these over-all objectives.

The over-all goal the Company was trying to accomplish as it designed its allocation methodology was to produce a reasonable method to allocate common costs and common plant by service and jurisdiction. The method ultimately proposed by Avista and approved by the state Commissions (Washington, Idaho, and Oregon) produced a reasonable allocation of common costs.

[51] The Company regularly surveys each member of its Avista Corp Board of Directors to determine how much of each member's time while serving on the Board is devoted to activities not directly related to the operations of the Utility itself, so that costs may be appropriately assigned to utility and non-utility operations. Current Board of Directors survey results show a 90% assignment to utility, and 10% to non-utility.

Q. Please explain when the Company began using the current methodology.

A. The current method used for electric generation and transmission expenses and net plant investment was reviewed and supported by the Washington and Idaho Commission staffs in 1984. This methodology uses the production/transmission ratio for electric expense FERC Accounts 500 through 573, which is described further below.

The current method for all other expenses (expense FERC Accounts 580 through 935) and net plant investment (i.e. excluding electric generation and transmission expenses and net plant investment), was developed and presented to the Commission staffs of Washington, Idaho and Oregon utility commissions for approval in 1993. The Company obtained approval letters from each jurisdiction and implemented the new utility codes and allocation methodology in 1994. This allocation methodology and the actual allocation of common costs using the factors computed using that methodology, have been provided in each general rate case filed by the Company in each of its jurisdictions since the method was implemented.

Q. When did the Company begin using the current service and jurisdiction codes?

A. The Company converted to the Oracle Financial System on January 1, 2005. With the implementation of the Oracle Financial System, the two-digit alpha codes for service and jurisdiction were adopted. The allocation methodology did not change with the implementation of the Oracle Financial System, but only the account code labeling was changed.

Q. Would you please identify the service codes that are used?

A. Yes. The Company uses the following service codes:

ED – Electric Direct
GD – Gas Direct
CD – Common Direct
ZZ – No Service (Used for balance sheet accounts (FERC Accounts 100-399) that are not assigned to a service (i.e. cash, accounts payable, etc.) and non-utility accounts)

Q. Would you please identify the jurisdiction codes that are used?

A. Yes. The Company uses the following jurisdiction codes:

AA – Allocated All
AN – Allocated North
ID – Idaho
MT – Montana
OR – Oregon
WA – Washington
ZZ – No Jurisdiction (Used for balance sheet accounts (FERC Accounts 100-399) that are not assigned to a jurisdiction (i.e. cash, accounts payable, etc.) and non-utility accounts)

Q. Would you please summarize the assignment and utility code/allocation method currently in use for costs?

A. Yes. To begin with, revenues, operating costs and plant are directly assigned to services and jurisdictions whenever possible.

As explained earlier, for those costs not directly assigned, the costs are allocated using a variety of allocation factors. The Company annually computes the allocation factors using actual direct costs and other data points (i.e. customer counts, customer usage, etc.). Updating the factors with current data on an annual basis is appropriate so that growth in each jurisdiction is factored into the current year allocation. When the factors are updated annually, the factors are reviewed to identify any unusual trends or unexpected shifts in costs.

Q. Would you describe the various types of allocation factors used by the Company?

A. Yes. The Company uses primarily three different types of allocation factors, including:

a) Allocation factors that are used to allocate common costs and are comprised of an equal weighting of four factors, and are therefore called "4-factors". The four factors are (1) direct O&M and A&G costs, excluding labor and resource costs, (2) direct O&M and A&G labor, (3) number of customers, and (4) net direct plant.

b) Allocation factors that use one data point (i.e. customer count or directly assigned distribution costs, etc.)

c) Allocation factors specific to electric costs or natural gas costs. These factors are the Production/Transmission (P/T) ratio for electric service and the System Contract Demand ratio for natural gas service, which are described below.

<u>Allocation Factors</u>

<u>Allocation of Electric Production and Transmission Costs and Plant</u>

Q. Would you please summarize the P/T ratio computation that is currently used to allocate electric generation and transmission costs and plant between Washington and Idaho?

A. Yes. The Company annually computes an allocation factor, called the P/T ratio (production/transmission ratio) using the previous year's actual usage amounts for retail customer demand and energy consumption. The kilowatt demand figures are the coincident contributions of each jurisdiction to the Company's monthly system peak loads. The kilowatt-hour energy consumption represents the actual sales figures. Both demand and energy use ratios are weighted equally in arriving at the allocation factor. This is Factor 1 for electric service.

Allocation of Natural Gas Underground Storage Costs and Plant

Q. Would you please summarize the System Contract Demand ratio computation that is currently used to allocate natural gas underground storage costs and plant?

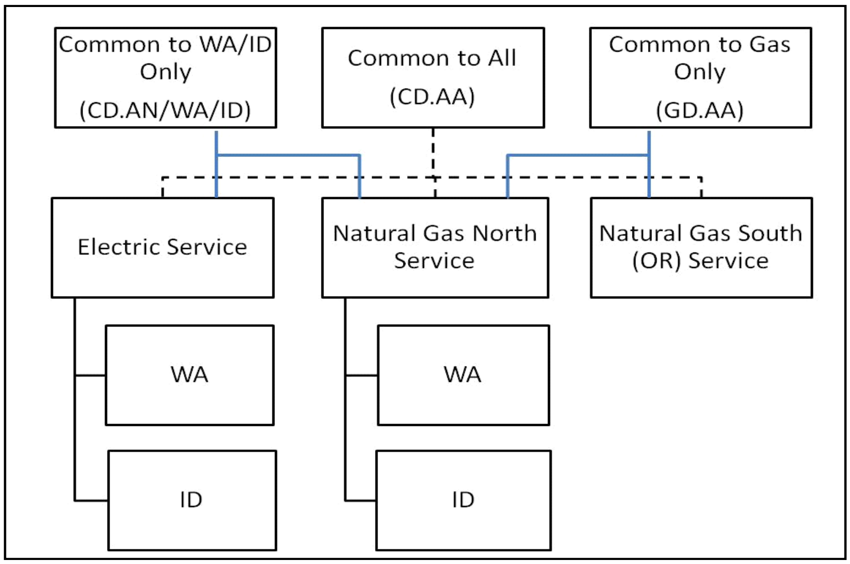
A. Yes. The Company annually computes the System Contract Demand allocation factor (also known as the five-day peak factor) using the actual therm throughput during the five consecutive days in the year with the highest throughput. The actual throughput for Washington and Idaho for this five-day period is averaged over three years, to determine the allocation of costs between Washington and Idaho. The Company directly assigns the O&M costs (FERC Account Nos. 824 and 837) of its share of the Jackson Prairie storage facility to Oregon and Natural Gas North Service, using the proportionate share of capacity assigned to each. Therefore, no further allocation of these costs to Oregon is required. This is Factor 1 for natural gas service.

<u>Allocation of Common Costs</u>

Q. Would you describe the allocation process used by the Company to allocate common costs?

A. Yes. Illustration No. 4 below depicts the allocation of common costs.

<u>Illustration No. 4</u>



The allocation of common costs is a two-step process. The first step is to allocate the common costs to one of the three <u>services</u>: Electric, Natural Gas North or Natural Gas South.

Three different 4-factors are used to allocate the common costs to the three services. These 4-factors are used to allocate all common costs recorded in all FERC Accounts, except FERC Accounts 901-905 (Customer Accounts Expense), FERC Accounts 906-910 (Customer Service and Information Expense), and FERC Accounts 911-917 (Sales Expenses). These costs in FERC Accounts 901 through 917 are heavily influenced by the number of customers, and therefore, it is more appropriate to allocate these common costs using the number of customers.

The three 4-factors that are used to allocated common costs to services follows:

- Factor 7 (CD.AA) – Factor used to allocate common costs to all services, including Electric, Natural Gas North and Natural Gas South. The 4-factor is developed using the following data:

  (1) Direct O&M and A&G costs, excluding labor and resource costs, that are assigned to electric service, natural gas North service and natural gas South service.
  (2) Direct O&M and A&G labor that are assigned to electric service, natural gas North service and natural gas South service.
  (3) Number of customers for electric service, natural gas North service and natural gas South service.
  (4) Net direct plant that is assigned to electric service, natural gas North service and natural gas South service.

- Factor 8 (GD.AA) – Factor used to allocate common natural gas costs to natural gas services, including Natural Gas North and Natural Gas South. The 4-factor is developed using the following data:

  (1) Direct O&M and A&G costs, excluding labor and resource costs, that are assigned to natural gas North service and natural gas South service.
  (2) Direct O&M and A&G labor that are assigned to natural gas North service and natural gas South service.
  (3) Number of customers for natural gas North service and natural gas South service.
  (4) Net direct plant that is assigned to natural gas North service and natural gas South service.

- Factor 9 (CD.AN) – Factor used to allocate costs common in Washington and Idaho to Electric service and Natural Gas North service. The 4-factor is developed using the following data:

(1) Direct O&M and A&G costs, excluding labor and resource costs, that are assigned to electric service and natural gas North service.
(2) Direct O&M and A&G labor that are assigned to electric service and natural gas North service.
(3) Number of customers for electric service and natural gas North service.
(4) Net direct plant that is assigned to electric service and natural gas North service.

These factors at June 30, 2013, used in this filing, are shown in Table No. 3 below:

Table No. 3

			Allocation Percentages		
Factor	Service Code	Jurisdiction Code	Electric	Natural Gas North	Natural Gas South
Factor 7	CD	AA	72.346%	19.401%	8.253%
Factor 8	GD	AA	0.000%	70.320%	29.680%
Factor 9	CD	AN/WA/ID	79.221%	20.779%	0.000%
Customer Ratio of Factor 7	CD	AA	52.888%	33.009%	14.103%
Customer Ratio of Factor 8	GD	AA	0.000%	70.065%	29.935%
Customer Ratio of Factor 9	CD	AN/WA/ID	61.572%	38.428%	0.000%

The second step is to allocate the common operating costs for Electric and Natural Gas North to the appropriate jurisdiction (Washington or Idaho).

These costs are allocated using the jurisdictional allocation factors, including:

- P/T ratio (Electric Factor 1), which was described above.
- System Contract Demand ratio (Natural Gas Factor 1), which was described above.
- Factor 2 (Number of Customers) – For both electric service and natural gas North service, Washington and Idaho's proportional share of total electric customers and total natural gas North customers are used to assign certain costs, as described below.

- Factor 3 (Directly-Assigned Distribution Costs) - For both electric and natural gas North service, Washington and Idaho's proportional share of total actual directly assigned distribution O&M expenses are used to assign certain costs, as described below.
- Factor 4 (Electric Common Costs) - Factor used to allocate common electric service costs to Washington and Idaho. The 4-factor is developed using the following data:

  (1) Direct O&M and A&G costs, excluding labor and resource costs, that are assigned to Washington and Idaho electric service.
  (2) Direct O&M and A&G labor that are assigned to Washington and Idaho electric.
  (3) Number of customers for Washington and Idaho electric.
  (4) Net direct plant that is assigned to Washington and Idaho electric service.

- Factor 4 (Natural Gas Common Costs) - Factor used to allocate common natural gas North service costs to Washington and Idaho. The 4-factor is developed using the following data:

  (1) Direct O&M and A&G costs, excluding labor and resource costs, that are assigned to Washington and Idaho natural gas North service.
  (2) Direct O&M and A&G labor that are assigned to Washington and Idaho natural gas North service.
  (3) Number of customers for Washington and Idaho natural gas North service.
  (4) Net direct plant that is assigned to Washington and Idaho natural gas North service.

- Factor 10 (Natural Gas Actual Annual Throughput) – For natural gas North service, Washington and Idaho's proportional share of total actual annual therm throughput are used to assign certain costs, as described below.

These factors at June 30, 2013, used in this filing for both electric and natural gas operations, are shown in Table No. 4 below:

Table No. 4

			Allocation Percentages	
Factors	**Service Code**	**Jurisdiction Code**	**Washington**	**Idaho**
Electric:				
PT Ratio (Electric Factor 1)	ED	AN	65.010%	34.990%
Customer Ratio (Factor 2)	ED	AN	65.618%	34.382%
Direct Distribution Costs (Factor 3)	ED	AN	66.932%	33.068%
Common Factor (Electric Factor 4)	ED	AN	67.000%	33.000%
Natural Gas:				
System Contract Demand Ratio (Nat. Gas Factor 1)	GD	AN	69.990%	30.010%
Customer Ratio (Factor 2)	GD	AN	66.411%	33.589%
Direct Distribution Costs (Factor 3)	GD	AN	70.462%	29.538%
Common Factor (Nat. Gas Factor 4)	GD	AN	70.603%	29.397%
Actual Annual Throughput Ratio (Factor 10)	GD	AN	69.163%	30.837%

These allocation factors are applied in a jurisdictional allocation model outside of the general ledger system. This model produces the monthly Results of Operations reports. Washington's Results of Operations reports as of June 30, 2013 have been provided with my workpapers at Section 1.00 for both electric and natural gas. Additional workpapers supporting the allocations described above are provided as Andrews Workpapers (Part 3), both in hard copy and electronic formats.

Allocation Methodology

Q. Would you describe for electric service for each income statement and rate base FERC account the allocation method that is used by the Company and a brief explanation of how the use of that factor produces a reasonable allocation of costs?

A. Yes. For electric operations, Table No. 5 below summarizes the various factors that are used for each FERC account.

Table No. 5:

Line	Description	FERC Accounts	Allocation Method to Electric/Natural Gas	Allocation Method to State
	Income Statement			
1)	Sales to Customers	440-446, 448, 499	Direct Assignment	Direct Assignment
2)	Other Sales, including Sales for Resale, Rent, etc.	447, 451-456	Direct Assignment	PT Ratio (Electric Factor 1)
3)	Generation O&M - Steam Power	500-514	Direct Assignment	PT Ratio (Electric Factor 1)
4)	Generation O&M - Hydro	535-545	Direct Assignment	PT Ratio (Electric Factor 1)
5)	Generation O&M - Other Generation	546-554	Direct Assignment	PT Ratio (Electric Factor 1)
6)	Other Power Supply (i.e. Purchased Power)	555-557	Direct Assignment	Direct Assignment or PT Ratio (Electric Factor 1)
7)	Transmission O&M	560-573	Direct Assignment	PT Ratio (Electric Factor 1)
8)	Distribution O&M	580-598	Direct Assignment	Direct Assignment or Factor 3 (Directly-Assigned Distribution Costs)
9)	A&G - Customer Accounts Expenses	901-905	Customer Ratio of Factors 7, 8 & 9 (Common Factor)	Customer Ratio (Factor 2)
10)	A&G - Customer Service and Info Expenses	908-910	Customer Ratio of Factors 7, 8 & 9 (Common Factor)	Customer Ratio (Factor 2)
11)	A&G - Sales Expenses	912-916	Customer Ratio of Factors 7, 8 & 9 (Common Factor)	Customer Ratio (Factor 2)
12)	A&G - Other Expenses	920-927, 930-935	Factors 7, 8 & 9 (Common Factor)	Factor 4 (Common Factor)
13)	A&G - Regulatory Expenses	928	Factors 7, 8 & 9 (Common Factor)	PT Ratio (Electric Factor 1)
14)	Depreciation and Amortization - Generation	403-404	Direct Assignment	PT Ratio (Electric Factor 1)
15)	Depreciation and Amortization - Transmission	403-404	Direct Assignment	PT Ratio (Electric Factor 1)
16)	Depreciation and Amortization - Distribution	403-404	Direct Assignment	Direct Assignment
17)	Depreciation and Amortization - General	403-404	Factors 7, 8 & 9 (Common Factor)	Factor 4 (Common Factor)
18)	Regulatory Amortizations	407	Direct Assignment	Direct Assignment or PT Ratio (Electric Factor 1)
	Rate Base			
19)	Intangible Plant and A/D	101, 108-111	Direct Assignment and Factors 7, 8 & 9 (Common Factor)	PT Ratio (Electric Factor 1) or Factor 4 (Common Factor)
20)	Generation Plant and A/D	101, 108-111	Direct Assignment	PT Ratio (Electric Factor 1)
21)	Transmission Plant and A/D	101, 108-111	Direct Assignment	PT Ratio (Electric Factor 1)
22)	Distribution Plant and A/D	101, 108-111	Direct Assignment	Direct Assignment
23)	General Plant and A/D	101, 108-111	Factors 7, 8 & 9 (Common Factor)	Factor 4 (Common Factor)
24)	Regulatory Deferred Assets and Liabilities	182, 186	Direct Assignment	Direct Assignment
25)	Working Capital	ISWC	Investor Supplied Allocation	Investor Supplied Allocation

Lines 1 through 7 – Customer revenues, generation O&M costs, power supply costs and transmission O&M costs are directly assigned to electric service in the general ledger. Revenues are primarily directly assigned to the states. The costs are either directly assigned to Washington and Idaho or are allocated to Washington and Idaho electric service using the P/T ratio. As discussed above, the P/T ratio is an equal weighting of actual usage amounts for retail customer demand and energy consumption. Since the P/T ratio is derived from actual sales data in each state, the use of the P/T ratio to allocate these costs produces a matching of costs with the revenues.

Line 8 – Distribution costs are directly assigned in the general ledger to electric service. The majority of costs are also directly assigned to Washington and Idaho. For those costs not directly assigned, the Company allocates the common distribution costs using the ratio of directly assigned distribution costs incurred in each state in comparison to the total.

Lines 9 through 11 – Customer count is one component of the 4-factors. Rather than using the over-all 4-factors (Factors 7, 8 and 9) to allocate the common costs to electric service for common portions of FERC Accounts 901-905 (Customer Accounts Expense), FERC Accounts 906-910 (Customer Service and Information Expense), and FERC Accounts 911-917 (Sales Expenses), the Company uses the customer component ratio of the 4-factors. These costs in these FERC accounts are heavily influenced by the number of customers, and therefore, the ratio based on customers is more appropriate to allocate the costs to electric and natural gas service than the over-all 4-factor. Using the same reasoning, the Company uses Factor 2 (Customer Ratio) to allocate the common electric costs to Washington and Idaho.

Line 12 - FERC Accounts 920-927 and 930-935 (Administrative and General) include various A&G costs, including salaries, office supplies and expenses, outside services, maintenance of common general plant, etc. The over-all 4-factor allocators

(Factors 7, 8 and 9) are used to allocate the common costs to electric service and the over-all 4-factor allocator (Factor 4) is used to allocate the common electric costs to Washington and Idaho. These costs are not influenced by any one factor, so the use of the over-all 4-factor that is equally weighted with customers, direct labor, other non-labor O&M and A&G direct costs and net direct plant, produces a reasonable allocation of common costs.

Line 13 – FERC Accounts 928 (Regulatory Commission expenses) include state and FERC fees that are based on revenues, in addition to other A&G expenses of the State and Federal Regulation department. The Company directly assigns the fees to electric service. For the state commission fees, the Company directly assigns the fees paid to each state to the appropriate state. For the FERC fees, the Company uses the P/T ratio to allocate the fees to Washington and Idaho. Since these fees are based on revenues, the use of the P/T ratio to allocate the fees produces the best matching of costs with revenues in each state. For the other common A&G expenses of the State and Federal Regulation department, the over-all 4-factors are used to allocate to electric service (Factors 7, 8 and 9).

Lines 14 through 15 – Depreciation and amortization expense of generation and transmission property are allocated using the same methodology as the generation and transmission O&M costs, described above for lines 1 through 7.

Line 16 – Depreciation and amortization expense of electric distribution property are all directly assigned.

Line 17 – Depreciation and amortization expense of general plant are allocated using the same methodology as the Administrative and General costs, described above for line 12.

Line 18 – FERC Accounts 407 (Regulatory Amortizations) are primarily directly assigned to the state where the deferral of costs originated. However, for electric service, there are deferrals that were approved in both Washington and Idaho related to the Coeur d' Alene Tribe Settlement (CDA Settlement) in 2008 that were recorded as a common electric deferral that is allocated to Washington and Idaho using the P/T ratio. The CDA Settlement relates to the use of the land for Avista's hydro generating facilities. Therefore, the P/T ratio is appropriate to allocate these costs.

Line 19 – Intangible plant accounts and associated accumulated depreciation (A/D) accounts include two groups of plant: 1) general intangible plant, like software, and 2) the CDA Settlement costs that were recorded as plant in 2008. The CDA Settlement costs are all directly assigned to electric service. General intangible plant and A/D is allocated to electric using the 4-factors (Factors 7, 8 and 9). The CDA Settlement costs are allocated to Washington and Idaho using the P/T ratio, using the same reasoning as describe in Line 18 above. General intangible plant and A/D is allocated to Washington and Idaho using the 4-factors (Factor 4). The amount of intangible plant, like software, is not directly influenced by just one factor, like customers; therefore the over-all 4-factors are used as a reasonable basis to allocate the rate base.

Lines 20-21 – Generation and transmission plant and associated A/D are directly assigned to electric service. Consistent with generation and transmission O&M costs and depreciation expenses, the rate base is allocated to Washington and Idaho using the P/T ratio.

Line 22 - Distribution plant and associated A/D are directly assigned to electric service and to each state.

Line 23 – General plant includes structures and improvements, office furniture, power operated equipment and transportation vehicles, etc. General plant and A/D is allocated to electric using the 4-factors (Factors 7, 8 and 9). General plant and A/D is allocated to Washington and Idaho using the 4-factors (Factors 4). The amount of general plant is not directly influenced by just one factor, like customers; therefore the over-all 4-factors are used as a reasonable basis to allocate the rate base.

Line 24 – Regulatory deferred assets and liabilities are all directly assigned to electric service and to each state that approved the deferral.

Line 25 – Working capital is computed using the investor supplied working capital (ISWC) method. Each balance sheet account is categorized. The remaining accounts (primarily non-earning short-term assets and liabilities) are allocated to service and states by the types of activity in each account. A variety of the allocation factors are used depending on the types of activity.

Q. Would you describe for natural gas service for each income statement and rate base FERC account the allocation method that is used by the Company and a brief explanation of how the use of that factor produces a reasonable allocation of costs?

A. For natural gas North operations, Table No. 6 below summarizes the various factors that are used for each FERC account.

Table No. 6

Line	Description	FERC Accounts	Allocation Method to Electric/Natural Gas	Allocation Method to State
Income Statement				
1)	Sales to Customers	480-484, 499	Direct Assignment	Direct Assignment
2)	Other Sales, including Sales for Resale, Rent, etc.	483, 488-495	Direct Assignment	Direct Assignment or Factor 4 (Common Factor)
3)	Production Expenses	804-813	Direct Assignment	Direct Assignment or Actual Annual Throughput Ratio (Nat. Gas Factor 10)
4)	Underground Storage	814-837	Direct Assignment	System Contract Demand Ratio (Nat. Gas Factor 1)
5)	Distribution O&M	870-894	Direct Assignment	Direct Assignment or Factor 3 (Directly-Assigned Distribution Costs)
6)	A&G - Customer Accounts Expenses	901-905	Customer Ratio of Factors 7, 8 & 9 (Common Factor)	Customer Ratio (Factor 2)
7)	A&G - Customer Service and Info Expenses	908-910	Customer Ratio of Factors 7, 8 & 9 (Common Factor)	Customer Ratio (Factor 2)
8)	A&G - Sales Expenses	912-916	Customer Ratio of Factors 7, 8 & 9 (Common Factor)	Customer Ratio (Factor 2)
9)	A&G - Other Expenses	920-927, 930-935	Factors 7, 8 & 9 (Common Factor)	Factor 4 (Common Factor)
10)	A&G - Regulatory Expenses	928	Factors 7, 8 & 9 (Common Factor)	Factor 4 (Common Factor)
11)	Depreciation and Amortization - U/G Storage	403-404	Direct Assignment	System Contract Demand Ratio (Nat. Gas Factor 1)
12)	Depreciation and Amortization - Distribution	403-404	Direct Assignment	Direct Assignment
13)	Depreciation and Amortization - General	403-404	Factors 7, 8 & 9 (Common Factor)	Factor 4 (Common Factor)
14)	Regulatory Amortizations	407	Direct Assignment	Direct Assignment
Rate Base				
15)	Intangible Plant and A/D	101, 108-111	Direct Assignment and Factors 7, 8 & 9 (Common Factor)	Factor 4 (Common Factor)
16)	U/G Storage Plant and A/D	101, 108-111	Direct Assignment	System Contract Demand Ratio (Nat. Gas Factor 1)
17)	Distribution Plant and A/D	101, 108-111	Direct Assignment	Direct Assignment
18)	General Plant and A/D	101, 108-111	Factors 7, 8 & 9 (Common Factor)	Factor 4 (Common Factor)
19)	Regulatory Deferred Assets and Liabilities	182, 186	Direct Assignment	Direct Assignment
20)	Working Capital	ISWC	Investor Supplied Allocation	Investor Supplied Allocation
21)	Gas Inventory	117, 164	Direct Assignment	System Contract Demand Ratio (Nat. Gas Factor 1)

Lines 1 through 2 – Customer revenues and other revenues are directly assigned to natural gas service in the general ledger. Revenues are primarily directly assigned to the states. There are other revenues that are allocated to Washington and Idaho natural gas service using the over-all 4-factor allocator (Factor 4). These other revenues are not influenced by any one factor, so the use of the over-all 4-factor that is equally weighted with customers, direct labor, other non-labor O&M and A&G direct costs and net direct plant, produces a reasonable allocation of common revenues.

Line 3 – Production expenses, including natural gas purchases are directly assigned to natural gas service in the general ledger. The majority of these costs are directly assigned to Washington and Idaho using the actual sales data for each month. A small amount of the costs are allocated using the prior year's actual annual throughput (Factor 10). Since all of these costs are allocated using actual sales data in each state, the use of these ratios to allocate these costs produces a matching of costs with the revenues.

Line 4 – Underground storage costs are directly assigned in the general ledger to natural gas service. The costs are allocated to Washington and Idaho using the System Contract Demand ratio. As described above, this ratio is the average of the highest 5 consecutive days of throughput for a 3-year period.

Line 5 - Distribution costs are directly assigned in the general ledger to natural gas service. The majority of costs are also directly assigned to Washington and Idaho. For those costs not directly assigned, the Company allocates the common distribution costs using the ratio of directly assigned distribution costs incurred in each state in comparison to the total.

Lines 6 through 8 - Customer count is one component of the 4-factors. Rather than using the over-all 4-factors (Factors 7, 8 and 9) to allocate the common costs to natural gas service for common portions of FERC Accounts 901-905 (Customer Accounts Expense), FERC Accounts 906-910 (Customer Service and Information Expense), and

FERC Accounts 911-917 (Sales Expenses), the Company uses the customer component ratio of the 4-factors. These costs in these FERC accounts are heavily influenced by the number of customers, and therefore, the ratio based on customers is more appropriate to allocate the costs to electric and natural gas service than the over-all 4-factor. Using the same reasoning, the Company uses Factor 2 (Customer Ratio) to allocate the common natural gas costs to Washington and Idaho.

Line 9 - FERC Accounts 920-927 and 930-935 (Administrative and General) include various A&G costs, including salaries, office supplies and expenses, outside services, maintenance of common general plant, etc. The over-all 4-factor allocators (Factors 7, 8 and 9) are used to allocate the common costs to natural gas service and the over-all 4-factor allocator (Factor 4) is used to allocate the common natural gas costs to Washington and Idaho. These costs are not influenced by any one factor, so the use of the over-all 4-factor that is equally weighted with customers, direct labor, other non-labor O&M and A&G direct costs and net direct plant, produces a reasonable allocation of common costs.

Line 10 – FERC Accounts 928 (Regulatory Commission expenses) include state fees that are based on revenues, in addition to other A&G expenses of the State and Federal Regulation department. The Company directly assigns the fees to natural gas service. For the state commission fees, the Company directly assigns the fees paid to each state to the appropriate state. For the other common A&G expenses of the State and Federal Regulation department, the over-all 4-factors are used to allocate to natural gas service (Factors 7, 8 and 9).

Line 11 – Depreciation and amortization expense of underground storage property are allocated using the same methodology as the underground storage costs, described above for line 4.

Line 12 – Depreciation and amortization expense of natural gas distribution property are all directly assigned.

Line 13 – Depreciation and amortization expense of general plant are allocated using the same methodology as the Administrative and General costs, described above for line 9.

Line 14 – FERC Accounts 407 (Regulatory Amortizations) are primarily directly assigned to the state where the deferral of costs originated.

Line 15 – Intangible plant accounts and associated accumulated depreciation (A/D) accounts includes general intangible plant, like software. General intangible plant and A/D is allocated to natural gas service using the 4-factors (Factors 7, 8 and 9). General intangible plant and A/D is allocated to Washington and Idaho using the 4-factors (Factors 4). The amount of intangible plant, like software, is not directly influenced by just one factor, like customers; therefore the over-all 4-factors are used as a reasonable basis to allocate the rate base.

Line 16 – Underground storage plant and associated A/D are directly assigned to natural gas service. Consistent with underground storage costs and depreciation expenses, the rate base is allocated to Washington and Idaho using the System Contract Demand ratio.

Line 17 - Distribution plant and associated A/D are directly assigned to natural gas service and to each state.

Line 18 - General plant includes structures and improvements, office furniture, power operated equipment and transportation vehicles, etc. General plant and A/D is allocated to natural gas using the 4-factors (Factors 7, 8 and 9). General plant and A/D is allocated to Washington and Idaho using the 4-factors (Factors 4). The amount of general plant is not directly influenced by just one factor, like customers; therefore the over-all 4-factors are used as a reasonable basis to allocate the rate base.

Line 19 – Regulatory deferred assets and liabilities are all directly assigned to natural gas and each state that approved the deferral.

Line 20 – Working capital is computed using the investor supplied working capital (ISWC) method. Each balance sheet account is categorized. The remaining accounts (primarily non-earning short-term assets and liabilities) are allocated to service and states by the types of activity in each account. A variety of the allocation factors are used depending on the types of activity.

Line 21 – Natural gas inventory is directly assigned to natural gas service in the general ledger. The costs are allocated to Washington and Idaho using the System Contract Demand ratio. This method is consistent with the method used to allocate underground storage costs, as described in Line 4 above.

Summary

Q. What portion of Washington's costs are allocated in the test period?

A. A summary of the costs for the test period (twelve months ended June 30, 2013) is provided in Table No. 7 below.

Table No. 7

Operating Costs
For the Twelve Months Ended June 30, 2013
($000's)

	WA Electric			WA Natual Gas		
	Direct	Allocated	Total	Direct	Allocated	Total
Power Supply/Generation & Transmission/Production/Underground Storage	$ 11,347	$ 395,045	$ 406,392	$ 136,095	$ 2,045	$ 138,140
O&M Distribution	15,401	5,734	21,135	7,898	2,758	10,656
Depreciation and Amortization	23,092	12,007	35,099	7,649	3,228	10,877
Administative and General	20,336	50,347	70,683	8,588	16,265	24,853
Taxes other than Income Taxes	39,617	-	39,617	12,532	-	12,532
Total Other Costs	98,446	68,088	166,534	36,667	22,251	58,918
Total	$ 109,793	$ 463,133	$ 572,926	$ 172,762	$ 24,296	$ 197,058

Excluding the allocated power supply, generation and transmission costs that are allocated using the P/T ratio, the Company has allocated $68,088,000 of costs to Washington electric service. This represents approximately 14% of total electric costs ($68,088/$572,926) that have been allocated to Washington electric service. Excluding the costs that are allocated using the P/T ratio, this represents approximately 41% of non-generation, transmission and power supply costs are allocated for electric service in Washington ($68,088/$166,534).

Excluding the allocated production and underground storage costs, the Company has allocated $22,251,000 of costs to Washington natural gas service. This represents approximately 11% of total natural gas costs ($22,251/$197,058) that have been allocated to Washington natural gas service. Excluding production and underground storage costs, this represents approximately 38% of non-production costs and underground storage costs are allocated for natural gas service in Washington ($22,251/$58,918).

Q. What portion of Washington's plant costs are allocated in the test period?

A. A summary of plant costs for the test period (June 30, 2013 AMA basis) is provided in Table No. 8 below.

Table No. 8

Plant Costs
Average of Monthly Averages at June 30, 2013
($000's)

	WA Electric			WA Natual Gas		
	Direct	Allocated	Total	Direct	Allocated	Total
Generation & Transmission/Underground Storage	$ -	$ 1,108,341	$ 1,108,341	$ -	$ 24,503	$ 24,503
Distribution	768,726	-	768,726	300,048	1,792	301,840
Intangible	2,762	52,535	55,296	965	7,282	8,247
General Plant	46,573	118,765	165,338	13,945	24,818	38,764
Total Other	818,061	171,300	989,360	314,958	33,892	348,851
Total	$ 818,061	$ 1,279,641	$ 2,097,701	$ 314,958	$ 58,395	$ 373,354

Excluding the allocated generation and transmission plant investment that are allocated using the P/T ratio, the Company has allocated $171,300,000 of plant costs to Washington electric service. This represents approximately 8% of total electric plant costs ($171,300/$2,097,701) that have been allocated to Washington electric service. Excluding the costs that are allocated using the P/T ratio, this represents approximately 17% of non-generation, transmission and power supply costs are allocated for electric service in Washington ($171,300/$989,360). Therefore, approximately 83% of non-generation and transmission plant costs are directly assigned for electric service in Washington.

Excluding the allocated underground storage plant, the Company has allocated $33,892,000 of plant costs to Washington natural gas service. This represents approximately 9% of total natural gas plant costs ($33,892/$373,354) that have been allocated to Washington natural gas service. Excluding the underground storage plant this represents approximately 10% of non-underground storage plant costs are allocated for natural gas service in Washington ($33,892/$348,851). Therefore, approximately 90% of non-underground storage plant costs are directly assigned for natural gas service in Washington.

Q. In summary, do you believe the allocation methodology used today by the Company is appropriate for allocating common costs?

A. Yes, I do. We believe the method used by Avista produces a reasonable allocation of costs. The allocation factors are derived using actual, directly assigned costs and other actual data points that are updated annually with current data, so growth in each service or jurisdiction is factored into the current year allocation. It has been reviewed and accepted by all jurisdictions in which Avista serves and remains a sound, rational basis for allocating costs.

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

A. Yes, it does.