BEFORE THE WASHINGTON

UTILITIES & TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION,

COMPLAINANT

V.

AVISTA CORPORATION, d/b/a AVISTA UTILITIES

RESPONDENT

DOCKETS UE-150204 and UG-150205 (*Consolidated*)

DIRECT TESTIMONY OF DONNA M. RAMAS (DMR-1CT)

ON BEHALF OF

PUBLIC COUNSEL

REDACTED VERSION

JULY 27, 2015

DIRECT TESTIMONY OF DONNA M. RAMAS (DMR-1CT)

DOCKETS UE-150204 and UG-105205 (*Consolidated*)

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I. INTRODUCTION

Q: Please state your name, occupation and business address.

A: My name is Donna M. Ramas. I am a Certified Public Accountant licensed in the State of Michigan and Principal at Ramas Regulatory Consulting, LLC, with offices at 4654 Driftwood Drive, Commerce Township, Michigan 48382.

Q: On whose behalf are you testifying?

A: I am testifying on behalf of the Public Counsel Unit of the Washington Attorney General's Office (Public Counsel).

Q: Please describe your professional qualifications.

A: A summary of my education, regulatory experience, and professional qualifications is attached as Exhibit No. DMR-4.

Q: What exhibits are you sponsoring in this proceeding?

A: I am sponsoring the following exhibits:

Exhibit No. DMR-2	Summary of Public Counsel Electric Adjustments
Exhibit No. DMR-3	Summary of Public Counsel Natural Gas Adjustments
Exhibit No. DMR-4	Qualifications of Donna Ramas
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Q: Have you previously filed testimony before the Washington Utilities and Transportation Commission ("UTC")?

A: Yes. I filed testimony before the UTC in Dockets UE-090205 and UE-140762 (consolidated), both of which involved Pacific Power & Light Company.

Q: What is the purpose of your testimony?

A: I present Public Counsel's overall base revenue requirement recommendation for Avista Corporation's electric operations and natural gas operations based on adjustments presented in this testimony. I also present testimony opposing Avista's proposed attrition approach in determining revenue requirements and explain why the attrition approach presented by Avista is not reasonable and will not result in fair and reasonable base rates to be charged to Washington ratepayers.

After addressing Avista's attrition request, I then focus on the cross check studies presented by Avista and recommend various adjustments to the cross check studies to determine fair and reasonable revenue requirements for Avista's electric operations and natural gas operations. As part of the discussion regarding Avista's proposed cross check studies, I also focus on key test year policy issues to ensure that rates are set based on known and measurable amounts that result in a matched test period.

Q: Did you undertake a comprehensive analysis and review of Avista's claimed revenue deficiency for its Washington jurisdictional electric and natural gas operations?

A: No, my review did not include a comprehensive review of all issue areas. Public Counsel may elect to support some adjustments made by other parties in this proceeding. As a result, I am not proposing a comprehensive "bottom line" revenue requirement on behalf of Public Counsel.

II. REVENUE REQUIREMENT SUMMARY

Q: Please summarize your primary conclusions and recommendations regarding Avista's proposed attrition approach and cross check analysis.

A: As a result of my review and analysis, I recommend that Avista's proposed attrition studies be rejected. Avista has not demonstrated that it is experiencing earnings attrition that results in its purported need for an increase in base rates for its electric operations. Moreover, as discussed later in this testimony, the attrition studies submitted by Avista in this case are biased and flawed. The attrition studies also incorporate projected and forecasted amounts extending 27 months beyond the test year ended September 30, 2014. The attrition studies, as submitted by Avista, essentially result in a future test year ending December 31, 2016, as opposed to the traditional hybrid test year approach that begins with a historic test period with limited pro forma known and measurable adjustments made thereto.

My recommended changes to electric and gas base revenues were developed by accepting and reflecting certain pro forma adjustments. The majority of my adjustments are made to ensure use of the hybrid test year method, which relies on actual known and measurable historic amounts for the test year with limited pro forma known and measurable adjustments. With respect to gas operations, the Company has consistently earned below its authorized rate of return, which leads me to recommend the use of end of period rate base and reflect certain known and measure post-test year capital plant additions.

Based on the recommendations and adjustments presented in this testimony, a $29,680,000 or 5.9 percent reduction in base electric revenues should be implemented. With respect to Avista's gas operations, I recommend an increase of $3,337,000 or 1.95 percent.

Q: What amount of rate increase is Avista requesting in this case?

A: In its original filing, dated February 9, 2015, Avista requested an overall increase in base electric revenues of $33.2 million or 6.6 percent and an overall increase in natural gas revenues of $12.0 million or 7.0 percent. On May 1, 2015, a Multiparty Settlement Agreement Stipulation was entered into by Avista Corporation, the Staff of the Washington Utilities and Transportation Commission ("Staff"), Public Counsel, Northwest Industrial Gas Users ("NWIGU"), and the Industrial Customers of Northwest Utilities ("ICNU") -- hereinafter referred to as

"Multiparty Settlement" -- which resolved several issues in this proceeding. With regards to the revenue requirement determination, the Multiparty Settlement resolved the capital structure and cost of capital issues for the electric and natural gas operations as well as certain power supply cost issues for the electric operations. Subsequent to reaching the Multiparty Settlement, on May 14, 2015, Avista submitted revised 2016 Attrition Studies in response to Staff Data Request No. 130 and revised cross check studies in response to Staff Data Request No. 131. On June 18, 2015, revised responses to Staff Data Requests Nos. 130 and 131 were provided to correct for input errors in the Electric Attrition Study and the synchronization of the Electric Cross Check Study to the Revised Electric Attrition Study. Both the attrition studies and the cross check studies result in the same change in rates because Avista adjusts the cross check studies to synchronize the resulting revenue requirement with the result of the attrition studies.

The revised studies provided in response to Staff Data Requests Nos. 130 and 131, and the corrections thereto, incorporated the impacts of the Multiparty Settlement as well as several corrections to the original studies presented by Avista.[1] While the revised cross check studies still use the September 30, 2014 actual operating results and components of the average-of-monthly-average rate base for the test year ended September 30, 2014, consistent with the original filed cross check studies, the Company revised the starting point in the new attrition studies. In the revised attrition studies provided in the original and revised

[1] See Exhibit Nos. DMR-5 through DMR-8.

response to Staff Data Request No. 130, the Company used the December 2014 Commission Basis Results from the December 2014 Commission Basis Report filed with the Commission on April 28, 2015, as the starting point in the analysis. Thus, different starting points are used in the Company's revised cross check analysis than is used in the revised attrition studies provided by the Company.

Based on the responses to Staff Data Requests Nos. 130 and 131 and revisions thereto, the resulting increase in Avista's base natural gas revenues declines from $12,021,000 as presented in its original filing to $9,713,000, and the resulting increase in base electric revenues declines from $33,229,000 to $10,037,000.

Q: Based on your analysis, what is your recommended change to the current level of base revenue requirements for the electric and natural gas operations?

A: Based on the adjustments and revisions presented in this testimony, I recommend that the proposed increase of $10,037,000 in electric base revenues reflected in the responses to Staff Data Requests Nos. 130 and 131 and revisions thereto be rejected. Instead, I recommend that a reduction in annual electric revenues of $29,680,000 or 5.9 percent be implemented. I also recommend that the proposed increase of $9,713,000 in natural gas revenues reflected in response to Staff Data Requests Nos. 130 and 131, and the revisions thereto, be reduced by $6,377,000 to $3,337,000 or 1.95 percent.

Q: What was the starting point in your determination of the amount of recommended changes in revenues for Avista's electric and natural gas operations?

A: In determining the recommended revenue requirements, I started with the revised cross check studies provided by Avista in response to Staff Data Request No. 131 and the revision thereto as these revised studies incorporated the impacts of the Multiparty Settlement and corrected a few errors contained in Avista's original cross check studies. As indicated above, the cross check studies also included adjustments to reconcile the results to Avista's attrition studies.

Q: Have you prepared any exhibits showing how your recommended revenue requirements were determined?

A: Yes. Exhibit No. DMR-2 presents the calculation of my recommended revenue requirement for the electric operations, which is a $29,680,000 reduction to current base rates. Exhibit No. DMR-3 presents the calculation of my recommended revenue requirement for the natural gas operations of $3,337,000. Schedule 1 of each of these exhibits provides a side-by-side comparison of Avista's proposed revenue requirements to that recommended in this testimony. Schedules 2 of Exhibit Nos. DMR-2 and DMR-3 provide a Summary of Adjustments for the electric and natural gas operations, respectively. Each Schedule 2 lists every adjustment incorporated in the Company's revised filing provided in response to Staff Data Request No. 131 and provides my recommendation on each of those adjustments. Avista's proposed adjustments which I am not addressing in this testimony are identified as "PC Neutral in

Direct," and the net operating income, rate base, and revenue requirement amounts associated with each of those adjustments as proposed are reflected in the Public Counsel columns of the exhibit. These items identified as "PC Neutral in Direct" does not necessarily signify agreement with Avista, and Public Counsel retains the right to adopt another party's position regarding these issues.

Avista's proposed adjustments that I recommend be modified are identified as "PC Modified" with my recommended net operating income, rate base, and revenue requirement impact from each of those adjustments presented in the Public Counsel Adjustments columns. New adjustments I propose that have not been addressed by Avista in its filing are identified as "PC Recommendation."

Lastly, Avista adjustments that I recommend be rejected by the Commission are identified as "PC Opposes" with the impacts on net operating income, rate base, and revenue requirement associated with those adjustments being shown as $0 in the Public Counsel Adjustments columns. The overall net operating income, rate base, and revenue requirements presented at the bottom of Schedule 2 for both the Avista columns and Public Counsel columns tie to the overall revenue requirements presented on Schedule 1 of each of the exhibits.

Exhibit No. DMR-2, Schedules 3 through 10, present the calculation of the electric operations adjustments identified as "PC Modified" or "PC Recommendation" on Schedule 2, as well as supporting information for an Avista adjustment that I recommend be rejected, as discussed later in this testimony. Schedule 11 presents an alternative approach should the Commission determine that the electric operations plant in service should be based on end of test year levels instead of the traditional Average of Monthly Average (AMA) approach. The impact on revenue requirements associated with the end of period approach presented on Schedule 11 is discussed later in this testimony.

Exhibit No. DMR-3, Schedules 3 through 9 present the calculation of the natural gas operations adjustments identified as "PC Modified" or "PC Recommendation" on Schedule 2 of the exhibit.

Q: You are recommending a fairly large reduction to the current electric rates. Can you explain why a reduction in electric base rates is a reasonable outcome in this case?

A: Yes. Avista is not experiencing the earnings attrition that it alleges in its case. As will be presented later in this testimony, Avista has been earning in excess of its authorized Return on Equity (ROE) for electric operations in each of the last two years. Avista experienced these over-earnings even before the most recent increase in rates approved by the Commission went into effect in January 2015. Additionally, in the Multiparty Settlement, the Company agreed to reduce the approved ROE to 9.50 percent.

Furthermore, one needs merely to look at the Avista Adjustment columns on Exhibit No. DMR-2, Schedule 2 to see that a rate reduction is warranted. This shows that based on Avista's own analysis, the restated total revenue requirement prior to application of the pro forma adjustments is negative $14,275,000. If one were to simply remove the revenue requirement associated with (1) Company Adjustment 4.01 that incorporates the impacts of its projected 2015 net plant additions on a December 31, 2015 end of period basis and (2) Company Adjustment 4.02 that incorporates the impact of the projected 2016 net plant additions on a 2016 AMA basis, the $10,037,000 increase in rates would instead be a reduction in rates of $20,278,000.[2] Only by incorporating several adjustments to extend plant additions well beyond the end of the test year and using a mis-matched approached in the revenue requirement equation is Avista able to contend that an increase in electric rates is needed. An example of the significant mis-match in the test period under Avista's approach is that projected net plant additions are taken out to December 31, 2016 levels, while revenues are based on weather normalized historic test year customer and usage levels in Avista's cross check studies.

III. AVISTA'S ATTRITION STUDIES SHOULD BE REJECTED

A. Attrition Definition and Background.

Q: Has the Commission previously described what attrition is?

A: Yes. In its September 27, 1993 Order in Docket UG-92840 involving Washington Natural Gas Company, in the first paragraph of the attrition section, the Commission stated:

> …Attrition is the change in the relationship among revenues, expenses, and rate base over time, in which growth in expenses exceeds growth in revenues from factors beyond the company's control. During periods when attrition threated a company's fiscal health and its ability to provide service, the Commission has allowed an attrition adjustment to rate case revenue requirements.[3]

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[2] ($10,037,000 - $27,639,000 – $2,676,000).

[3] *Washington Utilities & Transportation Commission v. Washington Natural Gas*, Docket UG-920840, Fourth Supplemental Order, 1993 WL500058 (Wash. U.T.C.), at 18.

In the same order, the Commission also addressed the attrition request as well as its past allowance of attrition adjustments as follows:

> The Commission concludes that no attrition adjustment should be granted in this case. An adjustment for attrition is an extraordinary measure, not generally included in general rate relief. A request for such an adjustment should be based on extraordinary circumstances, not shown by the Company to be present in this case.
>
> Past attrition adjustments have been allowed when the Commission found that, without such an adjustment, the company would have no reasonable opportunity to earn its authorized rate of return. The Commission does not believe that the company will be impeded from earning its authorized return in today's climate of low inflation, declining interest rates, and increasing gas sales. The company already has an approved tracker mechanism to pass through changes in its cost of gas. This purchased gas adjustment further reduces the risk that attrition will have a negative impact on the company's ability to earn its rate of return.[4]

The last case I am aware of in which the Commission explicitly approved an attrition adjustment was in UTC Cause No. U-6-02, a 1986 Pacific Power and Light Company rate case, which was resolved on September 19, 1986. In that Order, the Commission indicated that, "Attrition is the change in relationships between revenues, expenses and rate base that is expected to occur in the future time period after rates based on the historic pro forma test period are in effect."[5]

Q: Has the Commission more recently approved an attrition allowance or an overall attrition approach in setting rates?

[4] *Id.* at 19.
[5] *Washington Utilities & Transportation Commission v. Washington Natural Gas,* Cause No. U-86-02, Second Supplemental Order, 1986 Wash. UTC Lexis 7, at 21.

A: I am not aware of any cases since that September 1986 order in which the Commission has explicitly approved an attrition adjustment or set rates based upon an attrition study approach. It is my understanding that in approving a non-unanimous black-box settlement in Avista's 2012 general rate case, the Commission acknowledged that attrition was a component of the resulting revenue requirements; however, the Commission did not specifically address the appropriateness of the attrition approach presented by the Company in that case.

In Avista's last general rate case, Dockets UE-140188 and UG-140189, Avista presented an attrition study, but the all-party black-box settlement did not include agreement on whether an attrition adjustment was included in the settlement or appropriate. Finally, I understand the Commission is currently undertaking an investigation into possible ratemaking mechanisms to address utility earnings attrition in Docket U-150040. My understanding is that the investigation is ongoing and the Commission has not yet provided any formal policy guidance in this docket.

Q: Before addressing Avista's specific attrition studies and methods presented in this case, can you please provide your understanding of other approaches the Commission has used to address attrition and/or regulatory lag?

A: Yes. It is my understanding that the Commission uses a hybrid test-year approach which is primarily based on a historic test year that is adjusted for known and measurable changes that occur subsequent to the test year. In fact, in its recent Order in Docket UE-140762 (consolidated) involving Pacific Power & Light

Company, issued approximately four months ago on March 25, 2015, the Commission stated:

> …As Pacific Power is fully aware, Washington uses a hybrid test year approach that allows pro forma adjustments only for known and measurable changes –not budgeted or projected changes– that occur, generally within a reasonable time after the end of the test year and, with some exceptions, almost never more than 12 months after the end of the test year.[6]

In a footnote to the above quoted section (footnote 57), the Commission also stated:

> We note that it is even exceptional for the Commission to allow pro forma adjustments beyond a few months after the end of the test year. The Commission has relaxed this careful approach somewhat during recent years, risking violation of the matching principle, in an effort to address concerns that regulatory lag has been increasingly problematic during a period of unusually high capital investment. The Commission also has used other approaches, such as use of EOP rate base instead of the preferred AMA approach, and allowance of attrition adjustments, to address this problem. Nevertheless, companies we regulate continue to file regularly for general rate increases. …[7]

It is my opinion that a historic test year can continue to be used in a period in which attrition is being experienced with known and measurable post-test year adjustments made to offset the impacts of attrition if a utility is able to clearly demonstrate that it is, in fact, facing challenges caused by attrition. In situations where attrition or regulatory lag has been a concern, it is my understanding that

[6] *WUTC v. PacifiCorp d/b/a Pacific Power & Light Company*, Docket 140762 (consolidated), Order 08 at p. 21 (March 25, 2015).
[7] *WUTC v. PacifiCorp d/b/a Pacific Power & Light Company*, Docket 140762 (consolidated), Order 08 at p. 21, n.57 (March 25, 2015).

the Commission has approved the use of End of Period rate base when deemed warranted, although impacts on the matching principle have been identified as a problem under that approach.

Additionally, it is my understanding that Avista could request an Expedited Rate Filing (ERF). Use of an ERF would reduce regulatory lag if Avista does end up experiencing attrition in future periods.

B. Attrition Approach Presented by Avista.

Q: What attrition studies did Avista present in this case?

A: The original filed attrition studies were provided with the Direct Testimony of Elizabeth M. Andrews as Exhibit Nos. EMA-2 and EMA-3. In its original and revised responses to Staff Data Request No. 130, the Company provided updated attrition studies that incorporated significant changes from the original studies filed with its direct case. Under both the original studies and the revised studies, Avista, through various methods, is projecting or forecasting all of the revenue requirement components to a pro forma test period consisting of the twelve-month period ending December 31, 2016.

Q: What is the starting point of Avista's attrition study analysis?

A: In its original studies, Avista started with the Commission Basis Report for the period ended September 30, 2014, which is also the historic test year used in the cross check studies presented in this case. It then annualized the plant in service, accumulated depreciation, and Accumulated Deferred Federal Income Taxes ("ADFIT") to projected December 31, 2014 end of period values, and then escalated the resulting amounts to projected or forecasted levels for the year ending December 31, 2016.

Staff asked the Company if it had analyzed the impact of including its December 2014 normalized commission basis results in its 2016 Attrition Studies and to provide the resulting studies and supporting workpapers. In the Revised attrition studies provided in its original and revised responses to Staff Data Request No. 130, Avista started with the results from the December 2014 Commission Basis Report that was filed with the Commission on April 28, 2015. It then made several adjustments and applied various escalation and trend factors to determine revised projected or forecasted levels for the year ending December 31, 2016. As previously discussed, the revised attrition studies provided also incorporated the impacts of the Multiparty Settlement.

Q: Did Avista use consistent methods for projecting or trending the various components of the revenue requirement equation in its attrition studies?

A: No, it did not. A very selective and arguably biased approach was taken as opposed to a consistent trended approach. While I am not presenting all of the adjustments and trends applied in the Company's attrition studies, below is a summarization of the approaches used for some of the key components of the revenue requirement calculation. In discussing each, the identified factors are from the Electric Attrition Study, and a similar approach was used by Avista in the Natural Gas Attrition Study.

To project 2016 operating expenses, the Company used the six year period spanning 2007 to 2013 and determined the average annual compound growth rate of 5.82 percent. Avista then translated that growth rate to a 2.25 year escalation factor (i.e. going from 9/30/14 to 12/31/16, or 2.25 years) of 13.25 percent. However, the Company decided that it would instead use a 3.00 percent annual growth rate for operating expenses resulting in an escalation factor of 6.88 percent for the 2.25 year period. A similar approach using the 3.00 percent annual growth rate was used in the revised attrition study as well, only going out for two years instead of 2.25 years, given the later starting point of December 31, 2014 in the revised analysis.

For Adjusted Other Revenues and Adjusted Taxes Other Than Income, the Company used escalation factors calculated based on the average annual growth rate for the six year period spanning 2007 through 2013. In its revised filing, the updated escalation factor was calculated based on the seven year period spanning 2007 through 2014.

For Depreciation and Amortization Expense and Net Plant after Deferred Income Taxes, the escalation factors applied by the Company were based entirely on 2016 forecasted plant, accumulated depreciation, ADFIT, and depreciation and amortization expense amounts. In other words, the Company backed into the resulting escalation factors to ensure that the amount of plant, accumulated depreciation, ADFIT, and depreciation and amortization expense was based on its forecasted 2016 amounts.

Q: How do the calculated escalation factors using historic information for depreciation and net plant after deferred income taxes compare to the “escalation factors” applied by Avista in these areas?

A: Using the original attrition studies provided with the Company's filing, Table 1 below presents escalation factors calculated by Avista based on the use of historic data spanning from 2007 to 2013, as well as the escalation factors applied by Avista in going to the 2016 Attrition Year.

Table 1 - Escalation Factor Comparison - Original Studies

	Escalation Factor Based '07 - '13	Avista Applied Factor
Original Electric Attrition Study:		
Operating Expenses	13.25%	6.88%
Depreciation/Amortization	8.86%	18.57%
Net Plant after DIT	8.23%	11.71%
Original Gas Attriton Study:		
Operating Expenses	15.45%	6.88%
Depreciation/Amortization	13.20%	24.11%
Net Plant after DIT	9.31%	15.90%

Source: Exhibit No.__(EMA-2) and Exhibit No.__(EMA-3)

Avista provided revised attrition studies in its original and revised responses to Staff Data Request No. 130 which incorporated more recent data and the impacts of the Multiparty Settlement previously discussed in this testimony. Table 2 below presents the revised escalation factors calculated by Avista based on the use of historic data spanning from 2007 to 2014, as well as the escalation factors applied by Avista in going to the 2016 Attrition Year in its updated studies.

Table 2 - Escalation Factor Comparison - Revised Studies

	Escalation Factor Based '07 - '14	Avista Applied Factor
Revised Electric Attrition Study:		
Operating Expenses	10.53%	6.09%
Depreciation/Amortization	12.30%	22.20%
Net Plant after DIT	9.97%	12.44%
Revised Gas Attriton Study:		
Operating Expenses	11.95%	6.09%
Depreciation/Amortization	18.19%	27.92%
Net Plant after DIT	13.39%	13.96%

Source: Staff_DR-130-Revised-Attachment B and Staff_DR-130-Attachment C

Q: Is it correct that if the Commission were to adopt Avista's Attrition Studies and the approach used in those studies, rates would be set based on Avista's forecasted or budgeted plant additions spanning from the end of the test year to December 31, 2016?

A: Yes. Under Avista's proposed attrition study approach, rates would be set based on Avista's budgeted or forecasted plant additions for the period January 1, 2015 through December 31, 2016. Essentially rate base would be determined based on a future test year approach that incorporates forecasts and estimates. This is not an appropriate approach, and moreover, is not consistent with the hybrid test year approach based on historic amounts with limited known and measurable adjustments preferred by this Commission.

Q: What would the impact be if the escalation factors based on the forecast or budgeted plant additions and depreciation amounts were replaced with the escalation factors derived from the historic analysis approach?

A: Using the Electric Attrition Study provided in the revised response to Staff Data Request No. 130, Staff_DR_130 Revised – Attachment B, I replaced Avista's proposed escalation factors applied to Depreciation/Amortization and to Net Plant After Deferred Income Taxes with Avista's calculated escalation factors based on the historic period 2007 through 2014. The resulting Attrition Revenue Requirement went from Avista's revised and updated amount of $10,037,000 to only $404,000. Thus, simply changing the escalation rate for depreciation and net plant after Deferred Income Taxes (DIT) to the actual escalation rate experienced by Avista for the last seven years spanning from 2007 to 2014, essentially eliminated the purported need for an increase in electric rates.

Q: The Company asserts that it has experienced large growth in net plant investment in recent years which is largely driving its purported need for the attrition approach. If only more recent years are used in determining the depreciation and net plant after DIT escalation factors, does this show that an increase in rates is needed?

A: No. In fact, the opposite is true. Using the Electric Attrition Study provided by the Company in the revised response to Staff Data Request No. 130, Staff_DR_130 Revised – Attachment B, I replaced Avista's proposed escalation factors it applied to Depreciation/Amortization, Taxes Other Than Income and Net Plant After Deferred Income Taxes with Avista's calculated escalation factors based on the most recent three-year historic period of 2011 through 2014. This would cover the recent three years of higher capital expenditures. The result was that the Attrition Revenue Requirement went from Avista's revised and updated amount of $10,037,000 to a reduction in rates of $4,381,000. Thus, simply changing the escalation rates for depreciation, taxes other than income, and net plant after DIT to the actual escalation rate experienced by Avista for the three years spanning from 2011 to 2014, eliminated the purported need for an increase in electric rates, and instead resulted in a needed rate reduction. While the escalation rate over the most recent three year period for Net Plant after DIT was impacted by the bonus depreciation that was effective in recent years as well as the Company's Repairs Tax Deduction being taken for income tax purposes, it is not yet known if bonus depreciation or other potential legislation impacting deferred income taxes may be implemented between now and the end of the 2016 Attrition year. Whether or not new legislation will be passed that impact the ADFIT offset to rate base between now and the end of 2016 is not known and measureable, just as the Company's budgeted capital additions spanning to the end of 2016 are also not known and measurable.

Q: What are your conclusions regarding the Company's approach to developing its attrition studies?

A: As demonstrated in the two above examples, the approach taken in determining what escalation factors to apply, as well as what historic years are used in determining the escalation factors, has a large and significant impact on the results of the attrition studies. If one were to simply change the number of historic years used in the analysis for determining the escalation factors to apply, the results of the attrition studies changes substantially. Avista used six years in its original studies for determining certain of the factors (but not all of the factors), which it revised to seven years in its updated studies. The results differ significantly if the most recent three years are used and would differ yet again if a four or five year period, or even a ten year period, were selected. Avista's hybrid approach of using multiple historic periods, arbitrary escalations for operating expenses, and escalations based entirely on forecasted amounts for some areas creates a need for increased rates where none is needed with respect to electric operations. Avista's approach is not based on a clean historical analysis of actual attrition rates it has experienced. If a clean and consistent approach had been taken, the result would not be an increase in current rates for the electric operations under the Attrition approach.

C. Factors Offsetting Purported Need for Attrition Approach.

Q: In his direct testimony, Company witness Scott L. Morris addresses the relationship over time of the rate of growth in net plant investment, number of customers, and the use per customer. Are there any recent events that would offset the impacts on attrition caused by declines in customer usage?

A: Yes. Effective January 1, 2015, a full decoupling mechanism for Avista's electric and natural gas systems was implemented. The implementation of a decoupling mechanism for the electric and natural gas customers will offset the impacts of the decline in usage on a per customer basis addressed by Mr. Morris.

Q: Are there any additional mechanisms in place for Avista that would serve to offset the impacts of attrition and potential regulatory lag?

A: Yes. In addition to the recently implemented decoupling mechanisms for Avista, the Company also has a Purchased Gas Cost Adjustment and an Energy Recovery

Mechanism that accounts for fluctuations in power costs outside of an authorized band.

Q: Are there other means for addressing increases to plant in service that may be larger than has been previously experienced that could be used in addressing purported attrition or regulatory lag issues?

A: Yes. Under the hybrid test year approach based on a historic test period with known and measureable adjustments thereto, the Commission has several means of addressing perceived attrition or regulatory lag issues without needing to resort to a future test year approach or an attrition approach that incorporates forecasted and budgeted plant additions that are not known and measurable. For example, the Commission could consider including major post-test year plant additions that are known and measurable, which I have recommended as will be discussed in more detail later in this testimony.

Additionally, if a utility is able to clearly demonstrate that it is experiencing attrition or that it has been unable to achieve its authorized rate of return under the more traditional historic test year approach, the Commission can also consider using End of Period amounts for determining rate base to offset demonstrated attrition or regulatory lag issues. I recommend use of the End of Period approach for the natural gas operations. However, care should be taken under these approaches to ensure that there is not too great of a distortion in the matching of capital investments, revenues and expenses in the revenue requirement determination.

Another tool at the Company's disposal to address regulatory lag is its ability to request and file an Expedited Rate Filing (ERF). It is my understanding that if an ERF follows the principles adopted in a utility's most recent general rate case order, the ERF docket could be expected to be processed on a relatively faster procedural schedule as compared to a traditional rate case filing.

Q: Has Avista identified any investor owned electric or natural gas distribution companies whose rates are set based on an attrition approach similar to the approach it is proposing in this case?

A: No. In fact, Public Counsel Data Request No. 28[8] asked the Company to identify all jurisdictions in the United States that it is aware of that currently determine base rates for rate regulated investor owned electric or natural gas distribution companies based on an attrition approach similar to that proposed by the Company. Avista responded as follows: "The Company has not conducted a search related to the requested information." The Company did not identify a single utility that has rates in place that were determined using its proposed approach. While I have submitted testimony in over 100 regulatory proceedings in numerous jurisdictions, I am not aware of any rates being set based on an attrition approach such as that proposed by Avista in this case.

Q: Has the Company demonstrated that its financial situation has been impaired such that its proposed attrition study approach in setting rates which incorporates several years of projected plant additions is needed?

[8] Exhibit No. DMR-9.

A: No, it has not. In fact, the response to ICNU Data Request No. 29[9] shows that the actual return on equity ("ROE") achieved by Avista for its electric operations was 10.804 percent in 2013 and 11.532 percent in 2014 while the authorized ROE for the same period was 9.80 percent. Based on the Revised 2013 Electric Commission Basis Report filed with the WUTC on April 24, 2014, the normalized ROE for the electric operations in 2013 was 9.90 percent, which is also above the authorized ROE in effect at that time. Similarly, the response to Staff Data Request No.148[10] shows that the actual ROE achieved for the electric operations in 2014 was 11.53 percent while the normalized ROE for that same period was 10.60 percent, both of which exceed the 9.80 percent authorized ROE. Additionally, the Multiparty Settlement in this case provides for an agreed to ROE of 9.5 percent, and Avista's recent electric earnings have been well above this agreed to ROE.

While consistently lower ROEs are shown in the same responses for Avista's natural gas operations, later in this testimony I make several recommendations for additional consideration of known and measurable adjustments to the historic test year for the Commission's consideration specific to Avista's natural gas operations. I also recommend the use of End of Period (EOP) rate base for gas operations. It is my opinion that fair and reasonable rates can result for Avista's natural gas operations without needing to change to a rate determination methodology based largely on budgeted and forecasted amounts

[9] Exhibit No. DMR-10.
[10] Exhibit No. DMR-11.

that are not known and measurable.

D. Recommendation on Use of Attrition Studies.

Q: Based on your above testimony, is it accurate that you disagree with Avista that its attrition studies should be used in determining the revenue requirements for Avista's electric operations and natural gas operations?

A: Absolutely. I strongly recommend that the Company's proposed attrition studies be rejected outright by the Commission. The proposed attrition studies shift from a hybrid test year approach to a predominately future test year approach. This is a shift from a historic test year period with known and measurable adjustments to one that is based largely on budgets and forecasts that are not known or measurable. Avista's Attrition Study approach is not based on historic trending that projects revenue requirement components based on the recent historic relationship between rate base, revenue, and expenses, and the potential attrition experienced on that relationship based on recent historic results. Rather, it would result in a future test year approach based on forecasts and estimates.

Q: Since you recommend that the attrition studies be rejected outright, what is the starting point in your determination of a fair and reasonable revenue requirement for Avista?

A: For purposes of determining revenue requirements that result in fair and reasonable rates for Avista's electric and natural gas customers, I recommend that the revised and updated cross check studies provided by the Company in response to Staff Data Request No. 131 be used as the starting point in the analysis. As I will discuss in this testimony, significant revisions and adjustments need to be made to the cross check studies to ensure that rates are set based on a historic test year with known and measurable adjustments. I also recommend several adjustments and the adoption of several adjustments proposed in Avista's cross check studies which address regulatory lag.

Q: What adjustments did the Company make in its revised cross check studies to tie the revenue requirements in the revised cross check studies to the revised attrition studies?

A: In the Electric Cross Check Study provided in response to Staff Data Request No. 131 – Revised, the Company reduced net operating income by $371,000, reduced rate base by $16,679,000, and reduced the revenue requirement result by $1,363,000 to reconcile its revised and updated Electric Cross Check Study to its revised and updated Electric Attrition Study. Since I recommend the attrition studies be rejected, on Exhibit No. DMR-2, Schedule No. 2, I do not reflect the adjustment to reconcile the cross check study to the Electric Attrition Study in the Public Counsel Adjustments columns.

In the Natural Gas Cross Check Study provided in response to Staff Data Request 131, the Company increased net operating income by $177,000, increased rate base by $2,282,000, and reduced the revenue requirement result by $18,000 to reconcile its revised Natural Gas Cross Check Study to its revised Natural Gas Attrition Study. Since I recommend the attrition studies be rejected, on Exhibit DMR-3, Schedule No. 2, I do not reflect the adjustment to reconcile the cross check study to the Natural Gas Attrition Study in the Public Counsel

Adjustments columns. In other words, both the electric and natural gas the reconciliation adjustments should be rejected.

IV. TEST YEAR POLICY ISSUES AND APPROACH

Q: Before presenting your specific recommended adjustments to Avista's cross check studies and the adjustments made by Avista in those studies, are there any important test year policy issues you wish to discuss?

A: Yes. While the Commission has adopted adjustments in prior rate case proceedings aimed at addressing regulatory lag and possible impacts of attrition, it is important that each adjustment being made to a historic test period for post-test year or pro forma changes be carefully evaluated and considered. It is also important to evaluate whether the favored Average of Monthly Average ("AMA") approach or the End of Period ("EOP") approach should be used in determining the level of plant to include in rate base. The Commission has acknowledged the importance of carefully weighing post-test year adjustments in prior orders. The Commission has also addressed the fairly limited circumstances under which the EOP method of determining rate base has been adopted instead of the favored AMA approach. Whether or not an EOP approach or the AMA approach should be adopted in this case is discussed in further detail later in this testimony.

Earlier this year, the Commission issued its order in Docket UE-140762, Pacific Power & Light Company's general rate case. The Commission noted as follows:

> We note that it is even exceptional for the Commission to allow *pro forma* adjustments beyond a few months after the end of the test year. The Commission has relaxed this careful approach somewhat during recent years, risking

> violation of the matching principle, in an effort to address concerns that regulatory lag has been increasingly problematic during a period of unusually high capital investment. The Commission also has used other approaches, such as use of EOP rate base instead of the preferred AMA approach, and allowance of attrition adjustments, to address this problem. Nevertheless, companies we regulate continue to file regularly for general rate increases. …[11]

Additionally, the Commission addressed whether to adopt an EOP approach or the AMA approach in the prior Pacific Power & Light Company rate case in Docket UE-130043. The Commission stated as follows:

> In any future case in which PacifiCorp, or another party, proposes EOP rate base, we would expect to see a more fully developed record and a more refined approach to ensuring there is not a resulting violation of the matching principle.[12]

As clearly delineated in the Commission orders quoted above, a key principle to evaluate is the matching principle, which is the impact of the post-test year adjustments, as well as the selected approach to rate base, on matching rate bate base (or investments used to serve customers), revenues, and expenses. While some post-test year adjustments may distort the matching, care should be taken to avoid or minimize the impact on matching major revenue requirement components. Any adjustments or approaches that distort matching rate base, revenues, or expenses should only be adopted as an exception under extremely compelling circumstances.

[11] *WUTC v. PacifiCorp d/b/a Pacific Power & Light Company,* Docket No. 140762 (consolidated), Order 08 at p. 21, n.57 (March 25, 2015).
[12] *WUTC v. PacifiCorp d/b/a Pacific Power & Light,* Docket UE-130043, Order 05 at p. 73-74 (December 4, 2013).

Q: Beyond the matching principle, are there other key policy issues that also should be carefully evaluated and considered in addressing each of the pro forma adjustments proposed by the Company?

A: Yes. In addition to carefully evaluating the impact of post-test year adjustments and approaches on the matching principle, each adjustment should also be evaluated to ensure that rates are determined based on known and measurable amounts. The Commission addressed the known and measurable standard in Order 05 in Docket UE-130043 as follows:

> *Commission Determination*: Regulatory ratemaking involves, in many areas, the exercise of informed judgment. The reason Mr. McGuire found the Commission practice in accepting pro forma adjustments "highly variable" is because it is entirely appropriate for the Commission to make different determinations in different cases depending on the record in each individual case and the context in which the case is decided. While we will not take this occasion to expand on the point, a close reading of the Commission's general rate case orders over a significant period of time shows the Commission has consistently recognized the limits imposed by the "used and useful" and "known and measurable" standards while exercising the considerable discretion those standards allow in the context of individual cases.[13]

Additionally, the Commission addressed post-test year or pro forma adjustments with regards to the known and measurable standard in Docket UE-140762 as follows:

> As Pacific Power is fully aware, Washington uses a hybrid test year approach that allows *pro forma* adjustments only for known and measurable changes –not budgeted or projected changes– that occur, generally within a reasonable time after the end of the test year and, with

[13] *WUTC v. PacifiCorp d/b/a Pacific Power & Light,* Docket UE-130043, Order 05 at p. 79.

> some exceptions, almost never more than 12 months after the end of the test year.[14]

Q: Did the Company limit the adjustments presented in its cross check studies to known and measurable amounts that do not extend too far beyond the end of the historic test year?

A: No. Avista has made several pro forma adjustments for which the ultimate result is effectively to use a future test year ending December 31, 2016 for many, but not all, components of the revenue requirement equation. Although Avista's analysis begins with the more typical restating adjustments, then makes some of the more traditional post-test year adjustments for known and measurable changes, it also includes numerous pro forma adjustments that are based on budgeted or forecasted amounts to project many of the revenue requirement categories to a future test period. For example, the Company includes most of its projected additions to plant in service extending to December 31, 2016. It also bases projected property taxes, insurance expense, and various components of labor costs on forecasted 2016 levels.

In my discussion below, I present the adjustments that are needed to ensure that rates are determined based on the historic test period with known and measurable pro forma adjustments made thereto. I also present several adjustments to the natural gas operations for the Commission's consideration to address the consistent under-earning experienced for those operations, such as the

[14] *WUTC v. PacifiCorp d/b/a Pacific Power & Light*, Docket UE-140762, Order 08 at p. 21 (footnote excluded).

use of end of period rate base for the natural gas operations and consideration of several known and measurable post-test year major plant additions.

V. RECOMMENDED ADJUSTMENTS TO CROSS CHECK STUDIES

A. Remove Long Term Incentive Plan Expense.

Q: Please explain Avista's proposal regarding its Long Term Incentive Plan test year expenses.

A: According to the direct testimony of Jennifer S. Smith, the Executive Long Term Incentive Plan ("LTIP") "is a pay-at risk plan whereby executive officers and other key employees are eligible to receive common stock and dividend equivalents if stated targets are achieved and employment is maintained."[15] The LTIP awards are based on 25 percent restricted common stock units and 75 percent performance based stock equity awards.[16] The Company included the 25 percent associated with the restricted common stock units in the filing, claiming that it "is intended to provide an incentive for employees to remain employed by the Company and is therefore, appropriate to be included in rates."[17]

Q: What amount is included in Avista's filing for the Executive LTIP awards?

A: Ms. Smith states, "The amount of restricted stock expense included in the case, based on 2014 actual, is approximately $675,000 on a system basis or $325,000 Washington Electric."[18] The amount of $325,000 on a Washington electric basis is repeated in response to Public Counsel Data Request 10(b)[19] and no amounts

[15] Exhibit No. JSS-1T at 21:4-7.
[16] Exhibit No. JSS-1T at 21:9-10.
[17] Exhibit No. JSS-1T at 21:14-15.
[18] Exhibit No. JSS-1T at 22:1-2.
[19] Exhibit No. DMR-12.

were identified in the testimony or the response to Public Counsel Data Request No. 10(b) with regards to Washington natural gas operations. However, the response to ICNU Data Request No. 31[20] indicates that the cross check studies include $238,529 on a Washington electric basis and $70,758 on a Washington natural gas basis for executive LTIP expenses, which is $309,287 on a total Washington basis.

Q: Has Avista included any costs associated with the LTIP in retail rates in its prior general rate case proceedings?

A: No, it has not. In response to Public Counsel Data Request No. 9,[21] Avista indicated that it has not included LTIP costs in any of its last five general rate cases. In fact, the response to Public Counsel Data Request No. 23(a)[22] indicates that Avista reclassified the Restricted Stock portion of the LTIP on its books in September 2014, moving the costs from non-utility operations to Account 920, which is a utility operations account. The response also indicates that effective September 2014, the monthly accrual for restricted stock grants for all participants other than the Chief Executive Officer is now recorded in Account 920. Thus, Avista made a conscious decision to move the Restricted Stock portion of LTIP costs to expense accounts that are reflected in the revenue requirement calculations instead of excluding such costs from the utility operating books.

Q: How has the Restricted Stock portion of the LTIP been described to Avista's shareholders?

[20] Exhibit No. DMR-13.
[21] Exhibit No. DMR-14.
[22] Exhibit No. DMR-15.

A: In response to Public Counsel Data Request No. 17, the Company provided a copy of its 2015 Annual Proxy Statement. The Restricted Stock Units (RSU) portion of the LTIP is described for the non-CEO participants as follows:

> The Company awards RSUs to improve retention and link compensation to the value of the Company common stock. For all NEOs and other executive officers other than our CEO, the vesting of RSUs is time-based, and the RSUs vest and shares are issued in three equal annual increments, provided the executive remains employed by the Company on the last day of each year of the three-year period. Dividend equivalents on time-based RSUs accrue and are paid in cash if and when the underlying RSUs vest. If the related RSUs are forfeited, the accrued cash dividends are also forfeited. [23]

Q: Do you agree that the costs associated with the Restricted Stock Unit portion of the LTIP should be included in rates charged to Washington ratepayers?

A: No, I do not. Avista's novel and bold approach in this case of transferring these costs from shareholders to captive Washington ratepayers should be rejected outright. Clearly the Restricted Stock portion of the LTIP is tied to the value of the common stock and links a portion of the executives' compensation to the value of the Company's common stock. This benefits the shareholders of the Company as it places the LTIP participants' focus on Avista's stock value. These costs should continue to be excluded from rates. The Company has not presented compelling reasons that this compensation based on the value of the common stock should be shifted from shareholders to ratepayers at this time.

Q: What adjustment is needed to ensure that all LTIP costs are excluded from rates?

[23] Exhibit No. DMR-16.

A: As shown on Exhibit No. DMR-2, Schedule 3 (also identified as Adjustment PC-E2.18), test year expense should be reduced by $238,529 for electric operations. As shown on Schedule 2 of Exhibit No. DMR-2, this adjustment results in a $250,000 reduction to the electric revenue requirement. With respect to natural gas operations, Exhibit No. DMR-3, Schedule 3 (also identified as Adjustment PC-G2.15) shows that test year expense should be reduced by $70,758. As shown on Schedule 2 of Exhibit No. DMR-3, this adjustment results in a $74,000 reduction to the natural gas revenue requirements. Both of these reductions are based on the amounts presented in the Exhibit No. DMR-13, the Response to ICNU Data Request No. 31. However, if the amount actually incorporated in the cross check studies is higher than the amount identified in Exhibit No. DMR-13 and instead reflects the larger amount of $325,000 for Washington Electric operations as identified in Ms. Smith's testimony, then an additional adjustment would be necessary to ensure that all LTIP costs are excluded from the test year.

B. Non-Executive Wage Increases.

Q: What adjustments did the Company make to the test year labor costs for employee wage increases?

A: In adjusting the actual historic test year salary and wages for non-executive employees, Avista made four separate adjustments. Avista first annualized the impact of the 3 percent salary and wage increases that were implemented for 2014 for both union and non-union employees. While the union contract was approved in January 2015, the 3 percent increase for 2014 was retroactively applied in the agreement. The second adjustment included the annualized impact of a 3 percent wage increase for both union and non-union employees for 2015. The 3 percent non-union wage increase for 2015 has been implemented and became effective March 1, 2015. Ms. Smith's direct testimony, at page 26, indicates that the union increase of 3 percent was provided for in the current contract. The third adjustment increases non-executive labor costs for ten months of a projected 3 percent increase for union and non-union employees anticipated by Avista to be effective in March 2016. Since the Company is rolling certain costs forward to a 2016 rate period, it reflected ten months of the projected March 2016 wage increases. These three adjustments are discussed in Ms. Smith's direct testimony at pages 25 and 26. However, Avista's workpapers provided in support of the non-executive labor adjustments identifies a fourth adjustment being made to the test year labor costs which is not disclosed in the non-executive labor adjustment description presented in Ms. Smith's testimony.

Q: What is the fourth revision to the test year non-executive labor costs that is incorporated in the Company's adjustment workpapers?

A: The labor adjustment workpapers show an additional adjustment identified simply as "Plus Compass (see W/P)" which increases the test year labor expenses by $1,278,548 for the Washington electric operations and $379,177 for the Washington natural gas operations. The referenced workpaper identifies $2,324,867 recorded in FERC Account 107 – Construction Work in Progress during the test year and $154,075 recorded in FERC Account 186200 during the test year for a total amount of $2,478,942. The Company then applies each of the three wage increases previously discussed (i.e., annualization of test year wage increase, annualization of 2015 wage increases granted, and ten months of the projected 2016 wage increases) resulting in what is identified as "Total 2016 Compass Labor" of $2,650,009. This $2,650,009 is then allocated to the Washington electric and natural gas operations and transferred to expenses in the Company's filing. The Company shifts labor costs that were capitalized to the Project Compass IT project during the test year to expenses at escalated amounts. This increases the expenses incorporated in the test year by an additional $1,278,548 for the electric operations and $379,177 for the natural gas operations.

Q: Are you recommending any revisions to the Company's proposed increase in test year non-executive labor costs?

A: Yes. The salary and wage increases that were granted to the union and non-union employees during the test year and actual salary and wage increases granted to the union and non-union employees during 2015 have already occurred and are known and measurable. The 2015 increases were granted within six months of the end of the historic test year and, thus, are not too far removed from the test year. Therefore, I am not disputing the proposed annualization of these known and measurable increases that have already been granted to the non-executive employees.

However, the projected 2016 salary and wage increases for the non-executive employees are not yet known and measurable and are too far beyond the end of the test year ended September 30, 2014, to be incorporated in determining Avista's revenue requirements. As a result, I recommend that the impact of the projected 2016 salary and wage increases be removed from the adjusted test year. Additionally, I recommend that the Company's shifting of labor costs from capital to expense in the "Plus Compass" adjustment incorporated in its workpapers be rejected.

Q: Has the Commission recently addressed how far beyond the test year it will consider changes in labor costs?

A: Yes. In Docket UE-140762 (consolidated), the Commission addressed test year labor costs, including employee levels and wage increases, as follows:

> …As Pacific Power is fully aware, Washington uses a hybrid test year approach that allows pro forma adjustments only for known and measurable changes –not budgeted or projected changes– that occur, generally within a reasonable time after the end of the test year and, with some exceptions, almost never more than 12 months after the end of the test year.[24]

In a footnote to the above quoted section, the Commission also stated:

> We note that it is even exceptional for the Commission to allow pro forma adjustments beyond a few months after the end of the test year. The Commission has relaxed this careful approach somewhat during recent years, risking violation of the matching principle, in an effort to address concerns that regulatory lag has been increasingly problematic during a period of unusually high capital investment. The Commission also has used other approaches, such as use of EOP rate base instead of the preferred AMA approach, and allowance of attrition adjustments, to address this problem. Nevertheless, companies we regulate continue to file regularly for general rate increases. Pacific Power, for example, has filed one general rate case after another, year after year, as exemplified by its filing of this case only five months after the Commission authorized rate increases in Docket UE-130043 in 2013.[25]

[24] *WUTC v. PacifiCorp d/b/a Pacific Power & Light Company*, Docket UE-140762, Order 08 at ¶ 44.
[25] *Id.* at n.57.

Avista's proposal in this case to include projected salary and wage increases that are not known and measurable and are projected to be granted approximately 18 months after the end of the test year should be rejected.

Q: Why do you recommend that the Company's adjustment to shift labor costs from capital to expense in its "Plus Compass" adjustment be rejected?

A: The discussion of the pro forma non-executive labor adjustment presented in Ms. Smith's testimony did not disclose that a substantial amount of costs were being shifted from capital to expenses in its pro forma adjustment. Rather, the adjustment was buried in Avista's workpapers. Additionally, Avista has not provided evidence demonstrating that the ratio of labor going to expense and labor going to capital during the test year is not reflective of normal, on-going operations. The Company has not demonstrated that the total amount of labor costs needed for non-capital projects and charged to expense will increase after the completion of Project Compass or that the overall labor expense ratio will increase upon project completion. The Company has indicated that it is in a capital intensive period, which is inconsistent with its shifting of costs from capital to expense that is incorporated in its workpapers. In short, Avista has not demonstrated that the portion or ratio of overall labor costs to be charged to expense will increase after the test year. It has not supported its adjustment.

Q: What adjustments are needed to remove the projected 2016 salary and wage increases and the unsupported shifting of labor costs from capital to expense?

A: As shown on Exhibit No. DMR-2, Schedule 4 (also referenced as Adjustment PC-E.3.02), Avista's proposed non-executive labor expense adjustment for the electric operations should be reduced by $939,682 to remove the impact projected 2016 wage increases and by $1,278,548 to remove the shifting of labor costs from capital to expense. This reduces the Company's proposed expense adjustment from $3,850,480 to $1,632,250.[26]

As shown on Exhibit No. DMR-3, Schedule 4 (also referenced as Adjustment PC-G.3.00), Avista's proposed non-executive labor expense adjustment for the natural gas operations should be reduced by $281,739 to remove the impact projected 2016 wage increases and by $379,177 to remove the shifting of labor costs from capital to expense. This reduces the Company's proposed expense adjustment from $1,153,135 to $492,219.[27]

As shown on Schedules 2 of Exhibits Nos. DMR-2 and DMR-3, these adjustments reduce Avista's proposed revenue requirements by $2,325,000 for the electric operations and $693,000 for the natural gas operations.

C. Property Insurance Expense.

Q: What is the basis of the Company's adjustment to test year property insurance expense?

A: Avista increased the test year amount of general liability, Directors and Officers ("D&O") liability, and property insurance expense to reflect its projected 2016 expense levels. The Company's workpapers show that the Company started with

[26] $3,850,480 - $939,682 - $1,278,548 = 1,632,250.
[27] $1,153,135 - $281,739 - $379,177 = $492,219.

2014 invoiced amounts and escalated the various insurance policies by varying projected percentage increases for both 2015 and 2016 in calculating its proposed adjusted amounts. The total costs for these three types of insurances were increased from $4,917,693 in the test year ended September 30, 2014, to $5,575,651 for 2016 on a total Company basis, which is an overall increase of 13.4 percent. According to the direct testimony of Jennifer S. Smith, at page 30, Avista then removed 10 percent of its projected D&O liability insurance expense "as ordered in Docket UE-090134." The estimated insurance expense increases combined with the 10 percent reduction of the projected D&O liability insurance expense increases Avista's overall insurance expense by $259,423 for the electric operations and $76,948 for the natural gas operations.

Q: Is the Company's insurance expense adjustment known and measurable?

A: No, the adjustment is based on forecasted amounts and is not supported by known and measurable increases to the insurance costs. Additionally, the estimated costs extend to 2016 projected levels, which are well beyond the test year. Thus, the adjustment should be rejected.

Q: What adjustment do you recommend for insurance expense?

A: As shown on Exhibit No. DMR-2, Schedule 5 (also referenced as Adjustment PC-E.3.05), the actual test year insurance expense should be reduced by $53,932 on an electric operations basis to remove 10 percent of the D&O insurance expense. As shown on Exhibit No. DMR-2, Schedule 2, replacing the Company's proposed insurance expense adjustment with my recommended adjustment reduced the Company's proposed electric revenue requirements by $328,000.

Similarly, as shown on Exhibit No. DMR-3, Schedule 5 (also referenced as Adjustment PC-G.3.03), the actual test year insurance expense should be reduced by $15,997 on a natural gas operations basis to remove 10 percent of the D&O insurance expense. As shown on Exhibit No. DMR-3, Schedule 2, replacing the Company's proposed insurance expense adjustment with my recommended adjustment reduced the Company's proposed natural gas revenue requirements by $97,000.

D. Property Tax Expense.

Q: In each of the cross check studies, Avista makes two separate adjustments to property tax expense – one titled "Restate 2014 Property Tax" and one titled "Pro Forma Property Tax." What is the purpose of the "Restate 2014 Property Tax" adjustments?

A: In Ms. Smith's direct testimony, she indicates that the "Restate 2014 Property Tax" adjustments restate the property tax expense that was accrued during the test year to the amount that was actually paid during 2014, because the property tax expense for 2014 was based on actual plant balances as of December 31, 2013.[28] These adjustments increase test year property tax expense by $375,000 for the electric operations and $80,000 for the natural gas operations. I am not recommending any revisions to the property tax restatement adjustments.

Q: What is the purpose of the "Pro Forma Property Tax" expense adjustments?

A: In her testimony, Ms. Smith indicates that the pro forma property tax expense adjustments take the 2014 restated property tax expenses from the prior

[28] Exhibit No. JSS-1T at 14:6-7.

adjustments and increases them to projected 2016 expense levels. She indicates that the adjustment is based on the projected property values as of December 31, 2015, to reflect the 2016 level of expense that will be experienced by the Company in the rate period.[29] Upon review of Avista's workpapers, in addition to reflecting projected increases in property values extending to December 31, 2015, the adjustment also escalates the property tax rates or levies applied to the property values in each year with most of the effective tax rates being escalated by 2 percent per year.

Q: What is the resulting increase in property tax expenses?

A: The Company's pro forma property tax expense adjustments increase the property tax expenses that result from its property tax restatement adjustments by $3,181,296 for the electric operation and $507,109 for the natural gas operations.

Q: Do you agree that the approach taken by the Company in its pro forma property tax expense adjustment is reasonable?

A: No. I do not. It incorporates projected increases in property values extending to December 31, 2015, which are not known or measurable. The adjustment also projects expenses well beyond the test year. Additionally, the Company's annual escalation of the property tax rates or levies is also not known or measurable. The Company has presented no evidence demonstrating that the property tax rates will increase by the percentage escalation factors it is applying in its adjustment.

Q: Have you determined an alternative pro forma property tax expense adjustment for the Commission's consideration?

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[29] Exhibit No. JSS-1T at 31:1-6.

A: Yes. Using Avista's electronic property tax expense workpapers, I revised the adjustment to be based on the Company's per book 2014 plant value amounts and removed the escalation that was applied to the tax rates. Thus, the amount of revised property tax expense would be based on the Company's projected 2014 plant book values and the most recent effective property tax rates incorporated in the Company's workpapers without escalation. While this would not result in a perfect matching of the adjusted test year plant balances and property tax expenses as the plant values used go beyond the end of the historic test year, it does allow for an increase in property tax expenses associated with the increase in plant values that occurs from December 31, 2013 to December 31, 2014, and is a more reasonable alternative than that presented by the Company. As shown on Exhibit No. DMR-2, Schedule 6 (also referenced as Adjustment PC-E3.06), under my recommended approach, Avista's proposed $3,181,000 increase in electric property tax expense would be reduced to $1,127,000. Similarly, Exhibit No. DMR-3, Schedule 6 (also referenced as Adjustment PC-G.3.04) shows that my recommended approach reduces Avista's proposed $507,000 increase in natural gas property tax expense to $202,000.

As shown on Schedule 2 of Exhibit Nos. DMR-2 and DMR-3, replacing Avista's approach with my recommended approach reduces Avista's proposed electric revenue requirements by $2,153,000 and Avista's proposed natural gas revenue requirements by $320,000.

E. Information Technology and Services Expense.

Q: What adjustment did the Company make to its Information Service/Information Technology ("IS/IT") Expenses?

A: In its filing, Avista increased the historic test year IS/IT expenses by $3,152,978 on a total Company basis, which resulted in a $1,679,414 increase on a Washington electric basis and an increase of $412,039 on a Washington natural gas basis. The resulting proposed increase in revenue requirements is $1,760,000 on a Washington electric basis and $432,000 on a Washington natural gas basis. The IS/IT expense increase, which is based on the Company's projected or forecasted net increase in expenses, is discussed in the direct testimony of Avista witness James M. Kensok.

Q: What portion of the projected net increase is associated with the deployment of Avista's new Customer Service and Work and Asset Management Systems being implemented as part of Project Compass?

A: According to Mr. Kensok's testimony, Project Compass support costs are projected to result in a net increase to test year IS/IT expenses of $235,272.[30] This consists of projected incremental cost increases of $2,592,942 offset by projected cost reductions associated with the retirement of the Company's Legacy Customer Service and Work Management Systems of $2,357,670. The workpapers provided for Ms. Smith's testimony show that the $2,357,670 of cost reductions consists of a $1,368,870 reduction in contract labor costs and a $988,800 reduction in mainframe costs.

[30] Exhibit No. JMK-1T at 7:25-32.

Q: Is the full projected net increase in IS/IT costs incorporated in the Company's filing known and measurable?

A: No, the projected net increase is not known or measurable. Many of the individual IT/IS projects identified in Ms. Smith's workpapers are identified as "TBD" (i.e., To Be Determined) in the vendor column for the project. Thus, a large number of the projected cost increases are not supported by existing contracts. Rather, they are based on estimates and projections for 2016 cost levels that are not yet known or measurable.

Q: Was the Company asked to provide its executed IT/IS contracts that support the expenses for the 2016 costs identified in Ms. Smith's IS/IT expense workpapers?

A: Yes. Staff Data Request No. 180 posed the following question to the Company:

> For Jennifer Smith's work papers for PF-IT IS EXPENSE/"2015 PF – IS IT Adjustment"/ISIT-2 and ISIT-3, please provide all IT/IS contracts that have been agreed to and signed for expense listed under 2016 that are not part of the test year. Please also provide the pay schedule if available.

Q: Did the information provided in the response fully support the Company's projected net increase is IT/IS costs?

A: No, it did not. [redacted]

[redacted].

Q: What is your recommendation regarding the projected post-test year net increase in IS/IT expenses incorporated in the Company's filing?

A: Since the significant projected increase in the IS/IT expenses incorporated in Avista's filing is not known and measurable and would incorporate new costs that will not take effect until well after the end of the test year, I recommend that the Company's adjustment be rejected. As shown on Schedules 2 of Exhibit Nos. DMR-2 and DMR-3, removing Avista's proposed adjustment reduces the Company's proposed revenue requirements by $1,760,000 for the Washington electric operations and $432,000 for the Washington natural gas operations.

F. Generation O&M Expenses.

Q: What is included in the Company's adjustment to the Washington Electric Operations titled "Pro Forma Major Maintenance – Hydro Thermal, Other"?

A: In Avista's original filing, the adjustment increased test year expenses by $2,415,000 and included the Company's budgeted increases in major maintenance expenses planned for 2016 at hydro, thermal, and other generating plants, excluding the planned maintenance at the Colstrip and Coyote Springs 2 generating plants. The budgeted increase in major maintenance expenses planned for the Company's Colstrip and Coyote Spring 2 ("CS2") facilities were incorporated in its power supply adjustment in the original filing. As part of the Multiparty Settlement, Avista agreed to remove the Colstrip and CS2 operation and maintenance expenses from the base power supply costs, and that the revenue requirement related to these costs will be addressed in the unsettled portion of this case.

As a result of the Multiparty Settlement, and as the result of discovering an error in its original adjustment for pro forma major maintenance expense, the Company revised the Pro Forma Major Maintenance – Hydro Thermal and Other Adjustment. The revision increased the original adjustment by $3.4 million to add the projected incremental expenses associated with major maintenance projects at the Colstrip and CS2 generating facilities and reduced the original adjustment by $882,000 to correct an error that was disclosed to the parties in response to discovery. The final adjustment provided in the Revised response to

Staff Data Request No. 131 increases the historic test year expenses by $4,952,000 on a Washington electric basis.

Q: Is the adjustment to increase test year expenses by approximately $3.4 million for additional costs associated with major maintenance projects at Colstrip and CS2 known and measurable?

A: No. The projected increase is based entirely on budgeted or forecasted costs associated with these units for 2016. According to the Direct Testimony of Avista witness William G. Johnson, both Colstrip and CS2 are expected to incur major maintenance expenses that are $3,105,745 higher than the expense level in the historic test year on a Washington allocated basis.[31] Mr. Johnson also indicates that major maintenance is done every 2 out of three years at Colstrip with each unit undergoing major maintenance once every three years. Major maintenance on the CS2 unit is dependent on fired-run hours on the gas turbines with Avista anticipating the turbine will reach the hours needed for maintenance sometime in 2016.[32] The response to ICNU Data Request No. 177[33] indicates that the projected net increase in costs in 2016 at CS2 is mainly due to the Hot Gas Path maintenance planned for 2016 with Hot Gas Path major maintenance occurring on an approximately four year cycle based on hours of operation.

Q: Given Avista's assertion that it anticipates that major maintenance will be occurring during 2016 at both Colstrip and at CS2, should the forecasted costs that are not known or measurable be included in the adjusted test year?

[31] Exhibit No. WGJ-1T at 15:3-5.
[32] Exhibit No. WGJ-1T at 14:18-22.
[33] Exhibit No. DMR-17.

A: No. These projected costs go well beyond the historic test year ended September 30, 2014, and are not based on known and measurable amounts. Given the cyclical nature of the major maintenance projects at the generating facilities, it may be appropriate to normalize the costs if it can be demonstrated that the historic test year cost level is not reflective of normal operations. A historic average of the past operation and maintenance costs could be reviewed to evaluate whether or not the historic test year cost level is, in fact, not reflective of typical operations or would result in an unreasonable expense level being incorporated in rates. I have participated in rate case proceedings in which the generation unit overhaul expense to be incorporated in rates is based on historic averages of such costs so that rates are based on a normalized cost level.

Q: How do the actual historic operation and maintenance expenses for Colstrip and CS2 compare to the operation and maintenance expenses for the test year ended September 30, 2014?

A: Staff Data Request No. 174[34] asked the Company to provide the actual operations and maintenance expenses for both CS2 and Colstrip by FERC account and by month from January 2008 through 2014 and to separately identify the amounts related to major maintenance. In the response, the Company indicated that it "does not track the Colstrip and CS2 O&M by major and non-major activity." Thus, the Company provided the total operations and maintenance expenses for each of the plants for the period requested in the response without the breakdown between major and non-major. Exhibit No. DMR-2, Schedule 7 provides the

[34] Exhibit No. DMR-18.

annual Colstrip and CS2 operations and maintenance expenses provided by the Company for each year, 2008 through 2014. It also provides the actual expenses for the test year ended September 30, 2014, as well as Avista's estimated 2016 expenses. Also provided are the three-year average, four-year average, and five-year average expense levels based on the most recent periods ending 2014.

As shown on Exhibit No. DMR-2, Schedule 7, the actual test year expenses for CS2 were $5,892,996. As discussed previously in this testimony, Avista indicated that major maintenance at CS2 occurs approximately every four years. The four year average expense level for CS2 is $6,338,052, which is $445,086 higher than the historic test year expense. Avista's projected 2016 operation and maintenance expenses for CS2 are $9,334,860 which is considerably higher than the three-year, four year, and five year historic average costs.

Schedule 7 also shows that the actual test year operation and maintenance expenses for Colstrip were $12,996,535. As previously discussed, Avista indicated that major maintenance occurs at Colstrip two of every three years. The schedule shows that the most recent three-year average Colstrip operation and maintenance expense level was $12,138,912, which is $857,623 lower than the actual historic test year expense. Avista's projected 2016 operation and maintenance expenses for Colstrip are $15,005,259, which is considerably higher than the three-year, four year, and five year historic average costs.

Given the historic average operation and maintenance expense levels at CS2 and Colstrip as compared to the actual historic test year expenses for these units, a normalization adjustment does not appear to be warranted or necessary as the historic test year costs are not too far removed from the historic average cost levels. While the actual historic test year costs are lower for CS2 as compared to the three, four, and five-year average cost levels, the historic test year costs for Colstrip are higher than the three, four, and five-year average cost levels. As shown on Schedule 7, on a combined CS2 and Colstrip basis, the actual test year costs are actually higher than the four and five year average expense levels.

Q: Is the adjustment to increase test year expenses by approximately $1.5 million for additional costs associated with major maintenance projects at the hydro, thermal, and steam plants exclusive of Colstrip and CS2 known and measurable?

A: No. The projected increase is based entirely on budgeted or forecasted costs associated with planned maintenance projects at these units for 2016.

Q: Does a review of the historic major and non-major maintenance expenses at these generation units show that an increase in the historic test year cost level is needed or warranted to normalize the costs to be included in rates?

A: No, it does not. Avista provided the non-major maintenance expenses for the hydro, thermal, and steam facilities, exclusive of internal labor costs, for the most recent five years ended 2014 in response to Staff Data Request No. 41,[35] and the major maintenance expenses for these facilities for that same five-year period were provided in response to Staff Data Request No. 42.[36] These amounts, as well as the historic test year amount and Avista's estimated 2016 amount, are

[35] Exhibit No. DMR-19.
[36] Exhibit DMR-20.

provided on Exhibit No. DMR-2, Schedule 8. As shown on Schedule 8, the combined major and non-major maintenance expenses for the hydro, thermal, and steam facilities, exclusive of internal labor costs, are slightly higher in the historic test year ended September 30, 2014 ($4,349,450) than the average amount for the most recent five year period ($4,114,927). The test year expense level of $4,349,450 is also slightly higher than the most recent three year and four year averages. Thus, based on the test year expense compared to the prior periods and the averages thereof, it does not appear that a normalization adjustment is necessary. As also shown on Schedule 8, Avista's estimated 2016 expense level of $6,701,705 is considerably higher than the test year and any of the past five calendar years.

Q: What is your recommendation with regards to the Company's pro forma major maintenance expense adjustment?

A: Avista's adjustment should be rejected. The projected pro forma amount incorporated in Avista's revised and corrected Electric Cross Check Study is not known or measurable. Additionally, Avista has not demonstrated that the actual historic test year costs level needs to be normalized based on actual known and measurable historic cost data. As shown on Exhibit No. DMR-2, Schedule 2, reversing the Company's proposed pro forma major expense adjustment reduces its proposed revenue requirement for the electric operations by $5,191,000.

G. Post-Test Year Plant Additions.

Q: Previously in this testimony, you indicated that the Company included most of its projected additions to plant in service extending to December 31, 2016, in its cross check studies. Can you please elaborate?

A: Yes. The historic test period presented as the starting point in the cross check studies is the test year ended September 30, 2014. In both the electric and natural gas cross check studies, Avista made three major adjustments to include projected post-test year plant additions in rate base, each of which were modified in the revised cross check studies. The first adjustment was to go from the historic test year AMA approach to the projected amount as of December 31, 2014, which is an EOP approach. In its revised cross check studies provided in response to Staff Data Request 131, the Company updated the projected December 31, 2014 EOP balances to actual December 31, 2014 EOP balances. For the electric operations, the original filing added $94,965,000 to plant in service to go from the actual historic test year AMA approach to the projected December 31, 2014 EOP approach. In the revised cross check study, this amount was reduced substantially by $22,559,000. Thus, the Company's original projected plant additions for the last three months of 2014 proved to be inaccurate. For the natural gas operations, the original filing added $16,450,000 to plant in service to go from the actual historic test year AMA approach to the projected December 31, 2014 EOP approach, which was reduced by $1,469,000 in the updated cross check study. As part of the updated adjustment, the Company also incorporated the actual depreciation expense, accumulated depreciation, and ADFIT impacts associated with the plant additions.

The second significant post-test year adjustment made by Avista was to adjust to the projected December 31, 2015 EOP plant balances. In the revised cross check studies, this second adjustment added $213,413,000 more to the electric plant in service and $41,935,000 more to the natural gas plant in service balances to incorporate the budgeted 2015 plant additions.

The third significant post-test year adjustment made by Avista was to adjust the resulting December 31, 2015 EOP balances to the projected balances for 2016 using the AMA approach. In the revised cross check studies, this third adjustment added $31,010,000 more to the electric plant in service and $14,330,000 more to the natural gas plant in service balances to incorporate the budgeted 2016 plant additions.

As part of the 2015 EOP adjustment and the 2016 AMA adjustment, Avista also included the projected or budgeted impacts of the budgeted plant additions on depreciation expense, accumulated depreciation, and ADFIT.

Q: Has the Commission recently reiterated its definition of the known and measurable standard as it pertains to post-test year capital additions?

A: Yes. In Order 08 from Docket UE-140762, the Commission stated: "As recently as the Company's 2013 GRC, the Commission reiterated its definition of the known and measurable standard applicable to capital additions as follows…"[37]

[37] *WUTC v. PacifiCorp d/b/a Pacific Power & Light Company*, Docket UE-140762 (consolidated), Order 08 at p. 72.

The Commission then quoted the following from its December 3, 2013 Order in Docket UE-130043, Order 05 ¶ 205 (December 4, 2013) (quoting *WUTC v. PSE*, Dockets UE-090704 and UG-090705, Order 11 ¶ 26 (Apr. 2, 2010)):

> The known and measurable test requires that an event that causes a change in revenue, expense or rate base must be known to have occurred during, or reasonably soon after, the historical 12 months of actual results of operations, and the effect of that event will be in place during the 12-month period when rates will likely be in effect. Furthermore, the actual amount of the change must be measurable. This means the amount typically cannot be an estimate, a projection, the product of a budget forecast, or some similar exercise of judgment – even informed judgment – concerning future revenue, expense or rate base. There are exceptions, such as using the forward costs of gas in power cost projections, but these are few and demand a high degree of analytical rigor.

Q: Do you agree that Avista's adjustments to extend plant in service, depreciation, accumulated depreciation, and ADFIT to projected 2016 balances under the AMA approach is reasonable or appropriate?

A: Absolutely not. If adopted, Avista's proposed capital addition adjustments would base the major components of both rate base and depreciation expense on a future test period and on projections and forecasts that are not known or measurable. Under Avista's approach, budgeted plant additions extending 27 months beyond the end of the historic test period would be included, violating violate both the matching principle and the known and measurable standards in ratemaking. I recommend that the adjustments to project plant in service, depreciation expense, accumulated depreciation, and ADFIT to the budgeted December 31, 2015 EOP balances and to the budgeted 2016 AMA balances be rejected. I will address the

Company's proposed adjustment to extend these categories to the December 31, 2014 EOP balances in the next section of this testimony.

Q: Are there any post-test year plant additions that you would agree may be appropriate to include in the adjusted test year?

A: Yes. In past orders, the Commission has considered the inclusion of major plant additions on a project by project basis. The post-test year plant additions that have been allowed consisted of major plant additions that were used and useful with amounts that were known and measurable. Additionally, impacts of the major post-test year plant additions on the matching principle were also evaluated and considered by the Commission. For example, in Pacific Power & Light Company's last two rate case proceedings, the Commission allowed the inclusion of three <u>major</u> post-test year plant additions in each of those cases based on known and measurable amounts that were associated with plant that had been placed in service and was used and useful in providing service to customers prior to the inclusion in rates. The Commission rejected the inclusion of pro forma plant additions that were not considered major projects.

Following this Commission-accepted approach, I do not oppose the addition to plant in service for the following pro forma capital additions that have actually been placed into service by the Company since the end of the historic test year (i.e., since September 30, 2014): 1) capital costs closed to plant in service associated with the Clark Fork Protection, Mitigation and Enhancement ("PM&E") measures under the Clark Fork Settlement Agreement (electric operations); 2) Project Compass plant additions closed to plant in service (electric and natural gas operations); and 3) Aldyl – A Pipe Replacement capital additions (natural gas operations). As of Avista's most recent response to Staff Data Request No. 143, these are the only pro forma plant additions that are major plant additions and have actually been placed into service (used and useful) and are known and measurable in amount.

Q: What adjustment do you recommend for the Clark Fork PM&E capital additions?

A: Based on Avista's First Revised response to Staff Data Request No. 143,[38] $11,708,468 was placed into plant in service between October 1, 2014 and May 31, 2015, for the Clark Fork Implement PM&E Agreement capital projects. As shown on Exhibit No. DMR-1, Schedule 10, allowing the pro forma capital additions through May 31, 2015 (i.e., the known and measurable amount provided by Avista) associated with the project, test year plant in service would be increased by $11,708,468 on a Washington electric basis and test year depreciation expense would be increased by $218,948. In not opposing the addition of this project, it should be noted that I did not perform a detailed evaluation and audit of the costs reported by Avista in its response. Thus, I am not opining on the accuracy of the amounts reported by the Company in its data response and assume the amounts are used and useful since they have been placed into service on the Company's books. Other parties may challenge the addition based on various standards.

Q: What is Project Compass?

[38] Exhibit No. DMR-22.

A: Project Compass is the project under which Avista replaced its legacy Customer Information and Work Management Systems with Oracle's Customer Care and Billing solution and IBM's Maximo work and asset management application. According to the Direct Testimony of Avista witness James M. Kensok, the first day of service for these new systems was February 2, 2015, which falls just over 4 months beyond the end of the test year.

Q: What amount have you added to test year plant in service for Project Compass?

A: As part of its response to Public Counsel Data Request No. 32,[39] Avista identified $91,763,763 that was added to plant in service between October 2014 and April 2015, for Project Compass, with $44,215,399 added on a Washington Electric Operations basis and $13,182,547 on a Washington natural gas operations basis. As indicated above, the project was placed into plant in service on the Company's books in February 2015. As shown on Exhibit No. DMR-2, Schedule 10, I increased test year plant in service for electric operations by $44,215,399, ADFIT offset to rate base by $3,863,586, and depreciation expense by $3,698,176 for the project. For the natural gas operations, as shown on Exhibit No. DMR-3, Schedule 9, I increased test year plant in service by $13,182,547, ADFIT offset to rate base by $1,151,904, and depreciation expense by $1,102,588 for the project.

Q: In adding the amounts placed into plant in service on Avista's books for Project Compass, are you opining that the amount placed into service is prudent?

[39] Exhibit No. DMR-23.

A: No. I did not perform an in depth evaluation of Project Compass. This is a long term project taking several years to complete and place into service. I reviewed responses to various Staff data requests directed to this project, and it appears that the project cost was significantly higher than originally projected. It also appears that there were some potentially serious issues with the project implementation, costs, and performance prior to the go-live date in February 2015. Since I did not conduct an evaluation of the project costs and implementation from a prudence standard, an adjustment to reduce the amount for inclusion in rates charged to Washington ratepayers may be appropriate. The amount included in my pro forma major plant addition adjustment should be considered the maximum amount to include with the Commission considering reductions recommended by other parties in this case if prudence issues are raised.

Q: What amount are you adding to natural gas plant in service for the post-test year additions associated with the Aldyl – A pipe replacement program?

A: As shown on Exhibit No. DMR-3, Schedule 9, I recommend that natural gas plant in service be increased by $4,057,105 and depreciation expense be increased by a $102,239 for the Aldyl-A pipe replacement capital additions placed into service between October 1, 2014 and May 31, 2015.[40] While this project may not be of a very high dollar magnitude and could be border-line for consideration as a "major" capital addition, I recommend that the Commission consider this project

[40] Since the Aldyl-A pipe replacement project is an on-going longer-term project, if the Company provides additional known and measurable amounts that have been placed into service and used and useful in serving customers for the project after the May 31, 2015 date incorporated in my recommended adjustment, it may be reasonable for the Commission to include the additional known and measurable amounts closed to plant in service in rate base, along with the associated depreciation impacts, if such amounts are fully supported by the Company.

to be a major pro forma capital addition for the natural gas operations as a measure to address the consistent under-earnings for Avista's natural gas operations.

H. End of Period Rate Base Annualization.

Q: Are the Company's End of Period Rate base annualization adjustments limited to the test year ended September 30, 2014?

A: No. In the EOP adjustment, instead of reflecting the End of Period amount as of the end of the test year (i.e., September 30, 2014), Avista extended the EOP adjustment an additional three months to December 31, 2014, as part of its approach in rolling forward the plant in service, accumulated depreciation, and ADFIT balances to projected 2016 AMA balances. Thus, the EOP rate base adjustments and associated depreciation expense adjustments would take the balances three months beyond the end of the test year.

Q: Does the Commission typically accept the EOP approach for determining plant balances in rate base?

A: No. The Commission has accepted the EOP approach on a case by case basis and only as an exception to the preferred AMA approach. The AMA approach is the preferred method accepted by the Commission, as noted in the Commission's recent order in Docket UE-140762:

> *Commission Determination:* We first address Pacific Power's argument on brief, discussed immediately above, to underscore that the early case to which it cites does not establish a standard for determining when the use of EOP rate base is appropriate. The Commission's discussion in the first recent case approving this approach provides useful context:

> The Commission has traditionally required that utility rates be established relying on the measurement of rate base using the AMA approach. The Commission, however, has occasionally recognized that the alternative approach of utilizing end-of-test period rate base may be appropriate in a variety of circumstances. In a 1981 case, *WUTC v. Washington Natural Gas,* the Commission drew on its early experience evaluating the relative merits of the two approaches and drew the following conclusions:
>
> (1) Average rate base is the most favored,
> (2) Year-end rate base is an appropriate regulatory tool under one or more of the following conditions:
> (a) Abnormal growth in plant
> (b) Inflation and/or attrition
> (c) As a means to mitigate regulatory lag
> (d) Failure of utility to earn its authorized rate of return over an historical period.
>
> In the PSE cases, the Commission found that all of these "somewhat interrelated" issues were "present to one degree or another" at the point in time when the case was under consideration. Importantly, too, the Commission found "ample evidence" of "earnings attrition, caused by continuing growth in capital investments" as important to its consideration of historical under earnings.[41] (Footnotes omitted.)

Q: Do you recommend that Avista's electric operations rate base be set based on the EOP approach?

[41] *WUTC v. PacifiCorp d/b/a Pacific Power & Light Company*, Docket UE-140762, Order 08 at pp. 63 – 64, quoting from *WUTC v. Olympic Pipeline Company*, Docket TO-011472, Twentieth Supplemental Order, ¶¶ 158-160 and 370 (September 27, 2002) and citing to *Washington Utilities & Transp. Commission v. Puget Sound Power & Light Co.*, 7 PUR4th 44, 50 (September 27, 1974); *Petition of Puget Sound Energy and NWEC for Decoupling Authority*, Dockets UE-12167 and UG-121705 (consolidated); and *WUTC v. Puget Sound Energy*, Dockets UE-130037 and UG-130138 (consolidated), Order 07 ¶ 45 (citing *WUTC v. Wash. Nat. Gas Co.*, 44 P.U.R. 4th 435, 438 (Sept. 24, 1981)) (footnote omitted).

A: No, I recommend that rates be determined for the electric operations under the traditional AMA approach. As previously discussed, Avista's electric operations have been over-earning in excess of its authorized rate of return for the past two calendar years. This overearning is prior to the recent January 2015 implementation of the Company's most recent rate increase. While the Company has experienced growth in plant additions, this has been ongoing for several years, including the two most recent historic years. Additionally, I recommend inclusion of two post-test year major capital additions, which addresses the level of plant additions to some degree.

Q: If the Commission disagrees with your recommendation that test year rate base be determined under the Commission's preferred AMA approach, are there any revisions that need to be made to the Company's EOP adjustment?

A: Yes. As previously mentioned, the Company's initial EOP adjustment takes the plant additions and associated rate base components to December 31, 2014 levels, which is three months beyond the end of the test year. The Commission has acknowledged concerns with using the EOP approach with respect to the matching principle, and the mis-matching would be exacerbated if the EOP adjustment is taken further out to extend beyond the end of the historic test year.

Thus, if the Commission finds compelling reasons to make an exception to its preferred AMA approach and adopt an EOP approach for the electric operations, then at a minimum the Company's adjustment should be rolled-back to reflect the EOP balances as of the end of the historic test year, which is September 30, 2014. The necessary adjustment to roll-back the EOP adjustment from December 31, 2014, to the end of test year balances as of September 30, 2014, is shown on Exhibit No. DMR-2, Schedule 11. If the adjustment shown on Schedule 11 were adopted, the base revenue requirement recommended in this testimony for the electric operations would increase by $3,051,000, going from a reduction to electric base revenues of $29,680,000 to a reduction of $26,629,000. While I do not recommend the adjustment shown on Schedule 11 be reflected in Washington rates, I am providing it for the Commission's consideration should the EOP approach be adopted.

Q: Do you recommend that rate base for Avista's natural gas operations be set based on the EOP approach?

A: Yes. More compelling evidence exists demonstrating that an EOP approach may be appropriate for Avista's natural gas operations. As indicated previously in this testimony, the Company has consistently earned below its authorized rate of return for its natural gas operations. Additionally, the information provided by the Company indicates that an increase in rates may be warranted for the natural gas operations. Thus, I am not opposed to using an EOP approach to determine rate base for the natural gas operations. However, the EOP approach should be based on the end of the test period balances and not the December 31, 2014 balances proposed by the Company. Taking plant balances an additional three months beyond the end of the test year would result in too great of a mismatch in the revenue requirement equation. A mismatch would already result from using an EOP approach, and that mismatch should not be exacerbated by extending plant balances beyond the end of the test year, with limited exceptions for certain major pro forma plant additions.

Q: What adjustment is needed to reflect rate base on the test year EOP balances for the natural gas operations?

A: The adjustment needed to roll-back the EOP rate base adjustment from December 31, 2014 to September 30, 2014 end of test year balance is shown on Exhibit DMR-3, Schedule 7. This would reduce plant in service by $5,341,000, accumulated depreciation by $1,012,000, increase ADFIT by $155,000, and reduce depreciation expense by $316,000.

I. Advance Metering Infrastructure and Meter Retirements.

Q: What is the purpose of the pro forma adjustment in Avista's Electric Cross Check Study titled "Meter Retirement"?

A: Company witness Karen K. Schuh's direct testimony indicates that Avista has entered the initial planning phase of a program to deploy Advance Metering Infrastructure ("AMI") for its Washington electric and natural gas operations, with the project anticipated to be implemented over a six year span beginning in 2016.[42] The projected plant additions reflected in Avista's 2016 AMA plant addition adjustment discussed above includes $32.2 million associated with the AMI implementation.

Avista has projected that as of December 31, 2015, the remaining undepreciated balance on its books for the existing electric meters will be $20.2 million. Avista is proposing that it be authorized to transfer the $20.2 million net

[42] Exhibit No. KKS-1T at 26:7-11.

book value to a regulatory asset effective January 1, 2016, and begin to amortize that balance over a ten-year period beginning January 1, 2016. Thus, Avista has included $2 million in amortization expense to reflect the amortization of the proposed regulatory asset associated with the existing electric meters.

Q: Do you recommend that the new AMI meters the Company projects to add to plant in service in 2016 be included in the test year?

A: No, I do not. Previously in this testimony, I recommended that Avista's adjustment to incorporate the projected 2015 and 2016 plant additions in rate base be rejected, with a few limited exceptions for major plant additions that are known and measurable and already used and useful. Thus, as part of the recommended adjustment to remove the 2016 plant additions, I have also removed the projected 2016 AMI plant additions because they are neither known and measurable, nor used and useful.

Public Counsel witness Barbara Alexander presents Public Counsel's position on the AMI project. It is my understanding that the removal of the AMI meters projected by the Company to be placed into service during 2016 is also consistent with Ms. Alexander's recommendations regarding the AMI project.

Q: Do you agree that Avista should be permitted to defer the unrecovered costs associated with the existing electric distribution meters as a regulatory asset and begin to recover that regulatory asset as part of this case?

A: If Avista goes forward with the AMI deployment and, as a result, retires existing electric meters prior to the meters being fully depreciated on its books, I would not be opposed to transferring the unrecovered costs associated with the existing electric meters to a regulatory asset on the Company's books based on the remaining net book value when they are actually retired from service. However, I do not agree that rates being set in this case should include amortization of a projected future regulatory asset balance. Beginning recovery of the projected future regulatory asset is not necessary or reasonable at this time. Rather, any costs that are deferred in a regulatory asset associated with the early retirement of the existing electric meters should be considered in a future case when the actual amounts are known and measurable and <u>after</u> a prudence determination has been made by the Commission with regards to any new AMI program that may be implemented by Avista.

Ms. Alexander's testimony in this case indicates that Public Counsel is opposed to the AMI project as proposed in this case, which is consistent with my recommendation that Avista not be allowed to include the projected amortization associated with early retirement of the existing meters as part of this case.

J. Repairs Tax Deduction - ADFIT Impacts.

Q: Previously in this testimony, you recommended that certain pro forma major plant additions be included in the adjusted test year. You have also expressed your agreement with certain pro forma adjustments associated with known and measurable changes to expenses, such as labor cost increases and property tax expenses. Are there any additional pro forma adjustments that are known and measurable that should be made and incorporated in the revenue requirements in this case?

A: Yes. An additional adjustment to both the electric operations and the natural gas operations needs to be made to reflect the impact of the reduction in Accumulated Deferred Federal Income Taxes that is caused by the Repairs Tax Deduction being taken by the Company on its 2014 federal income tax return.

Q: What does Avista say in its original filing regarding the Repairs Tax Deduction ("RTD")?

A: Ms. Smith testifies as follows:

> The reduction in rate base is mainly due to an increase in DFIT as a result of Avista recording in the test period an estimate of the impact of a tax deduction the Company intends to file in its 2014 federal tax return. Avista plans to make a "Change of Accounting" filing to implement certain IRS Tangible Property Regulations associated with revised rules on property capitalization versus repair requirements. The study to implement this tax accounting change, which is commonly referred to as a "Repairs Study", will be finalized during the first quarter of 2015. In September 2014, the Company recorded its estimate with the best information available and does not expect he overall estimate to change materially.[43]

Q: Did the Company's estimate of the impact of the tax accounting changes associated with the RTD change materially when compared to the amount it booked in September 2014?

A: Yes, it did. As indicated in Revised Attachment A to Avista's response to Staff Data Request No. 131 (provided in Exhibit No. DMR-8), as part of Avista's adjustment to update its projected December 31, 2014 EOP plant balances to actual amounts, Avista also significantly revised the ADFIT offset to rate base. The attachment states, in part, "The reduction to Net Plant after DFIT was mainly

[43] Exhibit No. JSS-1T at 7, n.2.

due to a $50 million (system) reduction recorded to reflect a 'Repairs Allowance' allowed for tax purposes, and other DFIT true-up adjustments." Thus, Avista significantly increased the impact on ADFIT caused by the Repairs Tax Deduction after the end of the test year.

Q: Ms. Smith's testimony states that the study to implement the tax accounting change will be finalized during the first quarter of 2015. Did the Company provide the Repairs Study?

A: No, it did not. Public Counsel Data Request No. 49[44] asked Avista to provide a copy of the Repairs Study when completed. The response indicated that the study was not complete, and that Avista expects to have the completed study in July to August 2015.

Q: How does the impact on ADFIT resulting from the Repairs Tax Deduction booked by the Company by December 31, 2014, compare to the original projected amount book during the test year on September 30, 2014?

A: According to the response to Public Counsel Data Request No. 51,[45] the ADFIT related to the estimated results of the Repairs Study included in Avista's revised filing as of December 31, 2014, was $27,516,000 on a Washington electric operations basis and $6,590,000 on a Washington natural gas operations basis. The response to Public Counsel Data Request No. 49 (Exhibit No. DMR-25) indicates that the estimated results of the Repairs Study included in the unadjusted test year ended September 30, 2014, was approximately $9,046,000 for the

[44] Exhibit No. DMR-25.
[45] Exhibit No. DMR-24.

Washington electric operations and $2,683,000 for the Washington natural gas operations. Thus, the impact on the ADFIT offset to rate base associated with the RTD based on the amount it ultimately booked during 2014 was $18,470,000 higher than the amount reflected in the unadjusted historic test year for the electric operations ($27,516,000 - $9,046,000) and $3,013,000 higher for the natural gas operations ($6,590,000 - $3,013,000).

Q: Did Avista reflect the impact of the updated Repairs Tax Deduction in its filing?

A: Yes. As part of the revisions Avista made in updating and correcting its electric and natural gas cross check studies in its original and revised responses to Staff Data Request No. 131, the Company included the impact of the larger amount of ADFIT offset to rate base as part of its update adjustment to reflect actual December 31, 2014 EOP balances. However, since I have recommended that the adjustment to reflect EOP December 31, 2014 balances be rejected, the impact of the higher ADFIT offset to rate base has been removed as a result.

Q: Since the additional RTD was not booked until after the end of the test year (i.e., after September 30, 2014), should the impact be included in rate base?

A: Yes, it should. In calculating the amount of Repairs Tax Deduction that results from the Change of Accounting associated with the IRS Tangible Property Regulations, utilities typically apply the change in tax accounting method retroactively going back anywhere from ten to twenty years. Thus, the vast majority of the RTD that will be deducted on Avista's 2014 tax return would be applicable to plant that was placed into service prior to the September 30, 2014 end of test year. It is likely that only a small portion of the impact of the RTD booked by the Company on its books in 2014 would apply to the plant placed into service during the three month period between the end of the test year (September 30, 2014) and December 31, 2014.

Public Counsel asked Avista in Public Counsel Data Request 51 to provide a breakdown for both the electric and natural gas operations between the amount of ADFIT impact associated with the Repairs Tax Deduction associated with plant placed into service by September 30, 2014, and the amount associated with the post-September 30, 2014 additions. In response, Avista stated, "The amount associated with plant placed into service by September 30, 2014 and the amount associated with the post-September 30, 2014 additions is not available." Apparently, Avista made no attempts to separate the amounts in responding to the data request. Thus, since Avista has failed to provide the portion of its RTD and the resulting ADFIT impact resulting from the post-test year additions, and the fact that the majority of the deduction would pertain to plant placed into service prior to September 30, 2014, I recommend that the full amount of the increase in the Company's ADFIT offset booked during 2014 be reflected as an offset to rate base in this case. As shown on Exhibit No. DMR-2, Schedule 9, rate base should be reduced by $18,470,000 for the electric operations to reflect the additional RTD deduction. Similarly, Exhibit No. DMR-3, Schedule 8 shows that rate base for the natural gas operations should be reduced by $3,013,000.

K. O&M Offsets.

Q: What is the purpose of Avista's adjustments identified as "O&M Offsets"?

A: Avista went through the projected capital additions for the post-test year period spanning from October 1, 2014 through December 31, 2016, to estimate if any of the projected capital additions incorporated in the post-test year plant addition adjustments would result in O&M cost reductions or increases in costs. The workpapers provided with the filing for the O&M Offsets adjustment indicates that nine projects were projected to result in O&M cost reductions and three projects were projected to result in increased O&M costs. These exclude the Information Technology expense adjustment addressed previously in this testimony. The net result of the twelve projects was an estimated reduction in 2016 O&M expenses of $196,000 for the electric operations and $79,000 for the natural gas operations. These estimated expense reductions were reflected in the cross check studies.

Q: Do you agree that the "O&M Offsets" adjustments should be included in the adjusted test year?

A: No. Consistent with my recommendation that the majority of the post-test year plant additions be removed, the estimated O&M offsets associated with the post-test year plant addition should also be removed. Similar to the post-test year plant additions, the projected net savings are not known and measurable and extend beyond the test year, resulting in a mismatch of test year rate base (investments), revenues, and expenses. While I have recommended inclusion of several specific major post-test year plant additions that are known and measurable, Avista's O&M Offset adjustment is not related to the major post-test year plant additions I recommended for inclusion in rate base. Therefore, Avista's O&M Offset adjustment should be excluded. As shown on Schedules 2 of Exhibits Nos. DMR-2 and DMR-3, this increases the recommended electric and natural gas revenue requirements by $205,000 and $82,000, respectively.

VI. CONCLUSION

Q: Please summarize your recommendations.

A: Avista's proposed attrition studies should be rejected. The attrition studies submitted by Avista in this case are biased and flawed; they incorporate projected and forecasted amounts extending 27 months beyond the test year ended September 30, 2014. Adoption of the attrition studies submitted by Avista would essentially result in a future test year ending December 31, 2016, with mis-matched results as opposed to the traditional hybrid test year approach that begins with a historic test period that is adjusted with limited known and measurable pro forma adjustments. Given the earnings being experienced by Avista, it has not demonstrated that it is experiencing attrition that would justify an increase in rates for its electric operations.

Based on the recommendations and adjustments presented in this testimony, I recommend that base electric revenues be reduced by $29,680,000 or 5.9 percent. I also recommend that base natural gas revenues be increased $3,337,000 or 1.95 percent.

In determining the recommended change in electric and natural gas base revenues presented in this testimony, I began with the cross check studies provided by Avista and made various adjustments thereto, with the majority of the adjustments being made to ensure that the hybrid test year method is used which relies on actual known and measurable amounts for the test year with limited known and measurable pro forma adjustments thereto. I recommend the following adjustments be made to the cross check studies to ensure, to the extent possible, a matched test period that is based on known and measurable amounts with limited known and measurable pro forma adjustments:

- All costs associated with the LTIP, including the restrict common stock portion of the LTIP, should be excluded from the adjusted test year;
- Projected future salary and wage increases that are not known and measurable should be excluded from the adjusted test year, as well as the Company's unsupported shifting of capitalized labor costs to expense;
- Avista's adjustment to include forecasted property insurance expense amounts that are not known or measurable should be rejected;
- Property tax expense should be based on the known and measurable plant amounts as well as recent known and measurable property tax rates or levies instead of projected future plant levels and forecasted increases in tax rates;
- Avista's adjustment to increase information technology and services expense based on estimates and forecasts that are not supported by known and measurable net cost increases should be rejected;
- Avista's proposal to include significant budgeted cost increases associated with major generation plant maintenance projects is not known and measurable, and a need to normalize maintenance costs associated with major generation plant maintenance projects has not been demonstrated;

- Avista's proposed adjustments to incorporate forecast and projected net plant additions through December 31, 2016 should be rejected;
- Avista's proposal to include post-test year plant additions would result in a mis-matched test year and should be rejected, with limited exceptions for certain major plant additions;
- The Commission should consider inclusion of several post-test year major plant additions addressed in this testimony that are actually in service and used and useful in serving customers and based on actual known and measurable amounts;
- The Commission should reject the EOP approach for determining historic test year rate base for the electric operations for the reasons expressed in this testimony and instead base rate base on its preferred AMA approach for the historic test year;
- The Commission could adopt the EOP approach based on the test year ended September 30, 2014 balances for the natural gas operations as a means to address the under-earnings consistently being experienced by the natural gas operations, thereby addressing potential attrition and/or regulatory lag for those operations;
- Avista's proposal to begin amortizing a projected regulatory asset for the unrecovered costs of existing electric meters that would be retired early under its proposed AMI approach and include the associated amortization expense in rates resulting from this case should be rejected;

- An adjustment should be made to ensure that the impact on ADFIT associated with the Repairs Tax Deduction that Avista plans to incorporate in its 2014 federal income return and has already been booked in its financial records in 2014 is incorporated in rate base;
- Avista's proposed O&M expense offsets associated with several projected post-test year plant additions is not known and measurable and should be rejected.

Q: Does this conclude your direct testimony?

A: Yes, it does.