Exhibit No. BGM-1CT
Dockets UE-160228/UG-160229
Witness: Bradley G. Mullins
REDACTED

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION	)	
Complainant,	)	
v.	)	DOCKETS UE-160228 and UG-160229 (*Consolidated*)
AVISTA CORPORATION d/b/a AVISTA UTILITIES	)	
Respondent.	)	

CONFIDENTIAL RESPONSE TESTIMONY OF BRADLEY G. MULLINS

ON BEHALF OF

THE INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

AND

THE NORTHWEST INDUSTRIAL GAS USERS

(REDACTED VERSION)

August 17, 2016

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CONFIDENTIAL RESPONSE TESTIMONY OF BRADLEY G. MULLINS

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I. INTRODUCTION AND SUMMARY

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Bradley G. Mullins, and my business address is 333 SW Taylor Street, Suite 400, Portland, Oregon 97204.

Q. PLEASE STATE YOUR OCCUPATION AND ON WHOSE BEHALF YOU ARE TESTIFYING.

A. I am an independent energy and utilities consultant representing large energy consumers throughout the western United States. I am appearing on behalf of the Industrial Customers of Northwest Utilities ("ICNU") and the Northwest Industrial Gas Users ("NWIGU"). ICNU is a trade association whose members are large electric customers served by electric utilities throughout the Pacific Northwest, including Avista Corporation ("Avista" or the "Company"). Similarly, NWIGU is a trade association whose members are large gas customers served by gas utilities throughout the Pacific Northwest, including Avista. Accordingly, both organizations have an interest in ensuring that the electric and gas service rates of Avista are in the public interest.

Q. PLEASE SUMMARIZE YOUR EDUCATION AND WORK EXPERIENCE.

A. I have a Master of Science degree in Accounting from the University of Utah. After obtaining my Master's degree I worked at Deloitte Tax, LLP in San Jose California where I ultimately specialized in performing research and development tax credit studies. Subsequently, I worked at PacifiCorp as an analyst involved in regulatory matters surrounding power supply costs. I began performing independent energy and utility consulting services in September 2013 and currently provide services to utility customers on matters such as power costs, revenue requirement, rate spread and rate design. I have sponsored testimony in numerous regulatory jurisdictions throughout the West, including before the Bonneville Power Administration. A list of my regulatory appearances can be found in Exhibit No. BGM-2.

Q. WHAT IS THE PURPOSE OF YOUR RESPONSE TESTIMONY?

A. I present an analysis demonstrating that the Company's existing rates for gas and electric services are "sufficiently remunerative,"[1/] and therefore, that the Washington Utilities and Transportation Commission ("WUTC" or the "Commission") should not increase the Company's electric and gas services rates at this time. Even considering the application of an attrition allowance, my analysis shows that the Company's revenue requirements for both gas and electric services should actually be modestly reduced relative to the revenue requirement approved in the 2015 General Rate Case ("GRC").[2/]

Q. WHAT WAS THE NATURE OF YOUR EVALUATION OF THE COMPANY'S REVENUE REQUIREMENT?

A. I reviewed the Company's calculations supporting the proposed revenue requirement based on the Commission's traditional, modified test period methodology (the "Traditional" method). I also reviewed the Company's calculations used to establish its proposed attrition allowance revenue requirement (the "Attrition Allowance" method). Finally, I reviewed the Company's power cost forecasts, including the AURORA modeling presented as a part of the initial filing. As part of this review, I evaluated a large number of the Company's responses to data requests from ICNU, NWIGU, and other parties to this proceeding.

1/ RCW § 80.04.150

2/ WUTC v. Avista, Dockets UE-150204 and UG-150205 (Consolidated) (the "2015 GRC"), Order 05 (Jan. 6, 2016).

Q. BASED ON YOUR EVALUATION, PLEASE SUMMARIZE YOUR KEY RECOMMENDATIONS AND CONCLUSIONS.

A. Based upon my review, my key recommendations and conclusions are as follows:

- I continue to be concerned with several aspects of the "Attrition Allowance" method developed in the 2015 GRC, as the method does away with important ratepayer protections.
- Notwithstanding, if the Attrition Allowance method is to be used, I recommend a number of improvements to the model. After the application of these improvements, my testimony demonstrates that, under the Attrition Allowance method, the Company's revenue requirement should be reduced by approximately $3.8 million for electric services and $4.8 million for gas service.
- Under the Traditional revenue requirement method, I determined that the Company's revenue requirement should be reduced by approximately $5.4 million for electric services and $5.2 million for gas services.
- Finally, I recommend that the Commission reject the six-month rate plan proposed by the Company, as such a short *stay-out* does not provide sufficient value to ratepayers to warrant extraordinary ratemaking.

Q. ARE OTHER WITNESSES PROVIDING TESTIMONY ON BEHALF OF ICNU OR NWIGU IN THIS PROCEEDING?

A. Yes. Mr. Michael P. Gorman is providing testimony on behalf of ICNU regarding cost of capital. My revenue requirement calculations incorporate the cost of capital recommendation of Mr. Gorman. In addition, Mr. Robert R. Stephens will be providing testimony on behalf of ICNU on electric cost of service, rate spread and rate design issues. Finally, Mr. Brian Collins is also providing testimony on behalf of NWIGU on cost of service and rate spread issues.

II. ATTRITION, GENERALLY

Q. PLEASE PROVIDE SOME BACKGROUND ON THE ATTRITION ALLOWANCE METHODOLOGY.

A. In the Company's 2015 GRC, the Commission evaluated the use of an alternate ratemaking methodology explained on the basis of earnings attrition.[3/] This alternate methodology was used to justify the inclusion of a provision in revenue requirement commonly referred to as an "attrition allowance." Rather than relying on discrete known and measurable pro forma accounting adjustments—the Commission's traditional, long-standing practice—the Attrition Allowance method relied on principles of extrapolation to determine the ultimate revenue requirement used for ratemaking. In contrast with the Traditional method, the Attrition Allowance method also generally did not include an evaluation of whether the level of rate base reflected in revenue requirement was based on plant found to be "used and useful for service in this state."[4/]

Q. DID ICNU AND NWIGU OPPOSE THE USE OF THE ATTRITION ALLOWANCE METHODOLOGY IN THE 2015 GRC?

A. Yes. Both ICNU and NWIGU filed testimony in the 2015 GRC presenting arguments against the use of the Attrition Allowance methodology for ratemaking.

Q. DO ICNU AND NWIGU CONTINUE TO OPPOSE THE USE OF THE ATTRITION ALLOWANCE METHOD?

A. Yes. ICNU and NWIGU continue to be of the position that the Attrition Allowance method eliminates many of the ratepayer safeguards inherent to the Traditional

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3/ 2015 GRC, Order 05 at ¶¶ 47 – 141.

4/ RCW § 80.04.250.

ratemaking method that has been used by the Commission for decades. Accordingly, I continue to respectfully request that the Commission not approve revenue requirement based on the use of the Attrition Allowance method in this proceeding. Simply put, the public interest in Washington is best served if the standard for approving an attrition allowance remains relatively high. While the Commission may have lowered that standard in the 2015 GRC, approval of an attrition allowance should not be automatic and should not become the status quo. Granting an attrition allowance year after year will do little but encourage the utilities to file more frequent, and more aggressive, rate cases. It may also lead to over-earning, resulting in rates that are unreasonable and not in the public interest.

Q. HAS THE ATTRITION ALLOWANCE METHOD LED TO OVER-EARNING FOR AVISTA?

A. The financial repercussions of using the Attrition Allowance method are not yet understood, as they are only gradually being reflected in the Company's financial results. In recent years, however, the Company has seen a marked increase in its return on equity, above and beyond its authorized levels. Table BGM-1 below details the Company's returns over the period 2013 through the year ending June 2016. Note that the earnings for the year ending June 2016 are unadjusted and not normalized.

TABLE BGM-1
Avista Historical Earnings 2013 – 2016 (Return on Equity)

Ln		2013	2014	2015	Year Ending June 2016*
1	Washington Utility Service:				
2	Electric	9.90%	10.60%	9.40%	10.41%
3	Gas	7.20%	6.40%	7.00%	8.09%
4	Total Washington ROE	9.50%	9.90%	9.00%	10.20%
5	* Unadjusted				

Q. DOES THE ATTRITION ALLOWANCE METHOD RELY ON A KNOWN AND MEASURABLE STANDARD?

A. No. The Attrition Allowance method does not rely on a known and measurable standard to evaluate the rates charged by a public service company. As I noted in the 2015 GRC, "[a]n attrition adjustment represents an undistributed increase to a utility's revenue requirement. It is undistributed because it is not tied to any specific known and measurable cost, nor an item which can be demonstrated to be used and useful for the provision of utility service."[5/]

Q. WHY IS THE KNOWN AND MEASURABLE STANDARD IMPORTANT FOR RATEPAYERS?

A. Pursuant to RCW 80.04.130, the public service company has the burden of proof that the rate increase sought is just and reasonable. More precisely, the statute reads as follows:

> At any hearing involving any change in any schedule, classification, rule, or regulation the effect of which is to increase any rate, charge, rental, or toll theretofore charged, the burden of proof to show that such increase is just and reasonable shall be upon the public service company.[6/]

5/ 2015 GRC, Exh. No. BGM-1CT at 6:24-27.

6/ RCW § 80.04.130(4).

If the Commission is to move away from a known and measurable standard, in my opinion, it flips the "burden of proof" standard. It results in a situation where ratepayers carry the burden of proof to show that a rate increase based on historical trends will not continue into the future, rather than requiring the public service company to prove the specific, known and measurable cost items resulting in the rate increase.

Q. IS LOW LOAD GROWTH A REASON TO APPROVE AN ATTRITION ALLOWANCE?

A. While I understand there are challenges associated with operating a utility in a low load growth environment, an attrition allowance is not necessarily the best way to address low load growth conditions. Many public utilities located throughout the Northwest have been dealing with low load growth as an operational consideration for some time. Public power utilities located in rural areas have perhaps been impacted the most by this phenomenon. Yet, these utilities are able to continue to manage their operations by making difficult decisions regarding capital and operating expense.

Q. HOW SHOULD A UTILITY MANAGE LOW LOAD GROWTH CONDITIONS?

A. A utility operating in a low load growth environment needs to be very strategic in how it deploys capital and in how it manages operating expenses. It is not sustainable for a utility experiencing low rates of load growth to continually increase its annual rate of capital expenditures and operating expenses. Expenditures that are discretionary need to be deferred and those that are not discretionary need to undergo careful scrutiny to determine if there are other alternatives.

Q. DOES THE ATTRITION ALLOWANCE MODEL ENCOURAGE THE COMPANY TO BE STRATEGIC IN HOW IT MANAGES LOW LOAD GROWTH?

A. No. The Attrition Allowance method provides an even greater incentive for public utilities to increase capital expenditures than existed under the Traditional method. As the Commission acknowledged in the 2015 GRC, it has long been recognized that a public utility has a financial incentive to increase the amount of capital it deploys in any given year.[7/] This misalignment of interest between shareholders and ratepayers is commonly referred to as the Averch-Johnson effect.[8/] The Commission also acknowledged that the Attrition Allowance method increases this incentive to deploy capital, stating that "we are concerned about authorizing a practice that simply projects future levels of expense and capital expenditures that may, as multiple commenters point out, 'become a 'self-fulfilling prophecy' where there is an incentive for rates of capital expenditure to be driven by an effort to match earlier projections.'"[9/]

Providing an increased incentive for capital spending, however, is the exact opposite direction in which the Commission should be steering public utilities that are experiencing low load growth. Rather, a public utility experiencing low load growth should have incentives to slow and defer its capital spending. Thus, I am greatly concerned with the prospect of the long-term impacts associated with the Attrition Allowance method.

7/ 2015 GRC, Order 05 at ¶¶ 117-120.

8/ Id. at ¶ 117.

9/ Id. at ¶ 119 (citing *Investigation of Possible Ratemaking Mechanisms to Address Utility Earnings Attrition*, Docket U-150040, Public Counsel's Comments, ¶ 40 (Mar. 27, 2015) (quoting the testimony of David C. Gomez in Avista's 2014 GRC, Dockets UE-140188/UG-140149)).

Q. HOW HAS THIS INCENTIVE TRADITIONALLY BEEN PROVIDED TO PUBLIC SERVICE COMPANIES?

A. In my view, Washington's used and useful standard is one of the most important ratepayer safeguards not considered in the Attrition Allowance model. Under RCW 80.04.250(1), the Commission is required "to ascertain and determine the fair value for rate making purposes of the property of any public service company used and useful for service in this state." Under the Attrition Allowance model, however, the value of rate base, and its associated depreciation expense, is not reviewed under this standard. Rather, the rate base amounts are escalated irrespective of whether the ultimate amount of utility plant used for ratemaking exceeds the amount determined to be used and useful. As will be discussed below, this is a deficiency of the Attrition Allowance model that I propose to correct by capping the level of rate base based on a level determined to be used and useful by the Commission using the Commission's longstanding practice.

Q. PLEASE SUMMARIZE YOUR TESTIMONY ON ATTRITION.

A. While I understand there are challenges facing utilities experiencing low load growth, the approval of an attrition allowance is not, in my opinion, the best way for the Commission to address these challenges. Approving an attrition allowance, year after year, as a normal ratemaking method will incentivize public utilities to make capital decisions that are not in the best interest of ratepayers, particularly for those utilities experiencing low load growth. It will also do away with protections afforded ratepayers through the application of the known and measurable and used and useful standards. If the Commission is to continue to implement an Attrition Allowance methodology, however, I offer a number of suggestions in the following section for how it could be deployed more effectively.

III. ATTRITION ALLOWANCE METHOD

Q. HOW DO METHODOLOGICAL ASSUMPTIONS IMPACT THE ATTRITION ALLOWANCE METHODOLOGY?

A. The Attrition Allowance method relies on a number of methodological assumptions, which can have material impacts on the model results. The appropriateness of any one of these methodological assumptions, however, is not always a "black or white" proposition, as the model requires analytical discretion when evaluating the appropriate escalation rates, and other methodological inputs, in conjunction with a review of the reasonableness of the end results.[10/] This sort of discretion inherent in the Attrition Allowance model was noted by the Commission when it stated, referring to Hope, Bluefield, and Permian Basin: "We believe we can exercise broad discretion to consider such seminal cases using our informed judgment in deciding whether or not an attrition adjustment is warranted given the specific facts and circumstances in a rate case."[11/] To this end, if the Attrition Allowance model is to be used to inform the Commission's judgement in exercising this broad discretion, it ought to be based on assumptions that are fair and represent the Commission's informed view of what it reasonably expects in the future. That is, the model should not be used blindly, based on ridged, bright-line rules, which are known to be unrealistic.

Q. WHY DOES THE ATTRITION ALLOWANCE MODEL REQUIRE MORE DISCRETION THAN THE TRADITIONAL REVENUE REQUIREMENT METHOD?

A. The degree of discretion required with the Attrition Allowance model may be an artifact of the newness of the model. The nature of the model, however, also likely lends itself to

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10/ See id. at ¶ 129.

11/ Id.

more analytical judgement calls than does the Traditional method. This is probably due to the fact that small changes to an escalation rate can produce large changes to the overall revenue requirement produced by the model. In contrast, under the Traditional method, the pro forma adjustments at issue are typically less subjective, as the items are measured against a more precise known and measurable standard. In addition, under the Traditional method, small changes to a pro forma adjustment typically can have only a limited impact on revenue requirement, whereas minor changes to escalation factors can swing the Attrition Allowance revenue requirement by tens of millions of dollars.

Q. IS THE SENSITIVITY OF THE ATTRITION ALLOWANCE MODEL TO SMALL CHANGES AN INDICATION THAT IT IS UNRELIABLE?

A. Maybe. At a minimum, however, the sensitivity of the model to methodological assumptions means that the assumptions and inputs into the model ought to be subject to thorough scrutiny and that the model results ought to be reviewed for reasonableness.

Q. HAVE YOU REVIEWED THE ASSUMPTIONS UNDERLYING THE COMPANY'S ATTRITION ALLOWANCE MODEL?

A. Yes. I have reviewed the model and recommend a number of changes. In reviewing the methodological assumptions in the Attrition Allowance model, my analysis focused on four general areas. First, I reviewed the methodology used to develop the escalation rates. Second, I evaluated the appropriateness of making "after attrition" adjustments in the model. Third, I evaluated the appropriateness of the "attrition base" results of operations. Fourth, I evaluated whether the final attrition allowance results of operations satisfied the used and useful requirements of RCW 80.04.250. I would note that the application of the used and useful standard and the Attrition Allowance method are not necessarily mutually exclusive, as the Attrition allowance model can be deployed in a manner that takes the statutory standard into consideration.

Q. WHAT ARE THE CHANGES THAT YOU RECOMMEND?

A. Table BGM-2, below, provides a cross-walk between my Attrition Allowance model and the Company's. The results are detailed separately for electric and natural gas services. The details of these proposed changes will be discussed in the subsections that follow.

TABLE BGM-2
Cross-walk between Attrition Allowance Models
(Washington Revenue Requirement, $000)

Ln		Electric	Natural Gas
1	**Company Filing**	**38,568**	**4,397**
2	**Adjustments:**		
3	Cost of Capital (Gorman)	(9,283)	(1,876)
4	Escalation Rate Method - Linear Escalation	-	(71)
5	Escalation Rate Method - Escalation Rates Study	(14,694)	(4,092)
6	Post Attrition Adj. - Spokane River Projects	(6,875)	-
7	Pre- and Post-Attrition Adj. - AMI	(6,430)	(2,082)
8	Attrition Base - Remove 2015 Q4 Capital	(4,517)	(1,251)
9	Attrition Base - Increase Escalation to 2 1/4 Yrs.	2,180	497
10	Attrition Base - Director Fees	(352)	(101)
11	Less: Rate Base Not Used and Useful	(182)	(208)
12	Power Costs (Adj. 3.00 & Adj. 3.01)	(2,247)	-
13	**Total Adjustments**	**(42,400)**	**(9,184)**
14	**Proposed**	**(3,832)**	**(4,787)**

Q. WHAT ARE THE RESULTS OF YOUR RECOMMENDATIONS?

A. Exhibit No. BGM-3 details my Attrition Allowance model for electric services, and Exhibit No. BGM-4 details my Attrition Allowance model for gas services. As can be seen from those exhibits and Table BGM-2, above, my model recommends a revenue requirement reduction of $3.8 million for electric services and $4.8 million for natural gas services. I believe these results to be more reasonable than the Company's, due in part to the fact that they align more closely with the results of the Traditional revenue requirement model.

a. Escalation Rate Methodology

Q. HOW ARE ESCALATION RATES USED IN THE ATTRITION ALLOWANCE MODEL?

A. The Attrition Allowance model begins with a base results of operations. The base results of operations generally correspond to the Company's normalized, Commission-basis results, excluding power and fuel costs. While the base results are normalized and include several "restating" adjustments, the base results exclude "pro forma" adjustments. In place of the pro forma adjustments, however, the base results are increased by applying escalation rates to major cost categories in the base results. After applying the escalation rates to base results, forecast power and fuel costs are added back to develop a forecast results of operations. A revenue requirement calculation is then performed using the forecast results of operations to arrive at the Attrition Allowance revenue requirement.

Q. WHAT DO YOU MEAN BY "MAJOR" COST CATEGORIES, IN REFERENCE TO THE ESCALATION RATES?

A. In terms of "major" cost categories, the model used by the Company applies the same escalation rate to all rate base, for example, rather than calculating a separate escalation rate for the rate base attributable to the various rate base categories: intangibles, production, transmission, distribution, etc. Similarly, the Company's model applies the same escalation factor to all operations and maintenance ("O&M") expense, irrespective of whether the O&M expense is related to production, transmission, distribution, administrative expense, etc. Thus, the level at which the escalation rates are calculated in the Company's model is not very granular.

Q. HOW DOES THE COMPANY'S MODEL CALCULATE THE ESCALATION RATES?

A. The Company's model uses a different methodology to calculate the escalation rates for electric services than for gas services.[12/] For electric services, the model uses a linear regression of historical cost data, relying on the slope of the regression best-fit line to determine the escalation rate applicable to each category of cost. In contrast, for natural gas services, the model uses a quadratic formula to determine the escalation rate applicable to each category of cost. For natural gas services, the model uses the derivative of the best-fit quadratic curve to determine the escalation rate, rather than the slope of the trend line. The use of a quadratic formula for natural gas, versus a linear best-fit line for electric services, appears to be consistent with the analysis of Mr. McGuire of Commission Staff in the 2015 GRC.[13/]

Q. OVER WHAT HISTORICAL TIME PERIOD WERE THE ESCALATION RATES CALCULATED?

A. The Company's Attrition Allowance model used the time period 2007 through 2015 to calculate the escalation rates for both electric and natural gas services. In addition, the model used the same period for all categories of cost, irrespective of whether each cost category demonstrated a clear trend over the period. With the exception of the cost data

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12/ See Exh. No. EMA-1T at 24:5-25:11.

13/ See 2015 GRC, Exh. No. CRM-3 Revised (Oct. 13, 2015).

for 2015, which was based on the results for the year ending in September 2015, the cost data used in the escalation factor calculations were based on calendar year financial results.

Q. WHAT ARE YOUR RECOMMENDATIONS WITH RESPECT TO THE ESCALATION RATE METHODOLOGY?

A. I recommend a number of improvements to the methodology for calculating escalation rates. First, I propose to use a linear regression for both electric and natural gas services, doing away with the quadratic curve in the natural gas study. Second, I propose to evaluate the escalation rates using more granular categories of cost than evaluated in the Company Attrition Allowance model. Specifically, I calculate a specific escalation rate applicable to each line item in the Company's results of operations, which should help to better evaluate the reasonableness of the model results. Third, I performed a case by case review of the historical cost data for each category of cost to determine the appropriate data to rely upon to calculate the escalation rates, including evaluation of an appropriate time period to use when evaluating the trend for the cost category in question.

Q. WHY DO YOU PROPOSE TO ELIMINATE THE QUADRATIC FORMULA ASSUMED IN THE NATURAL GAS ATTRITION ALLOWANCE MODEL?

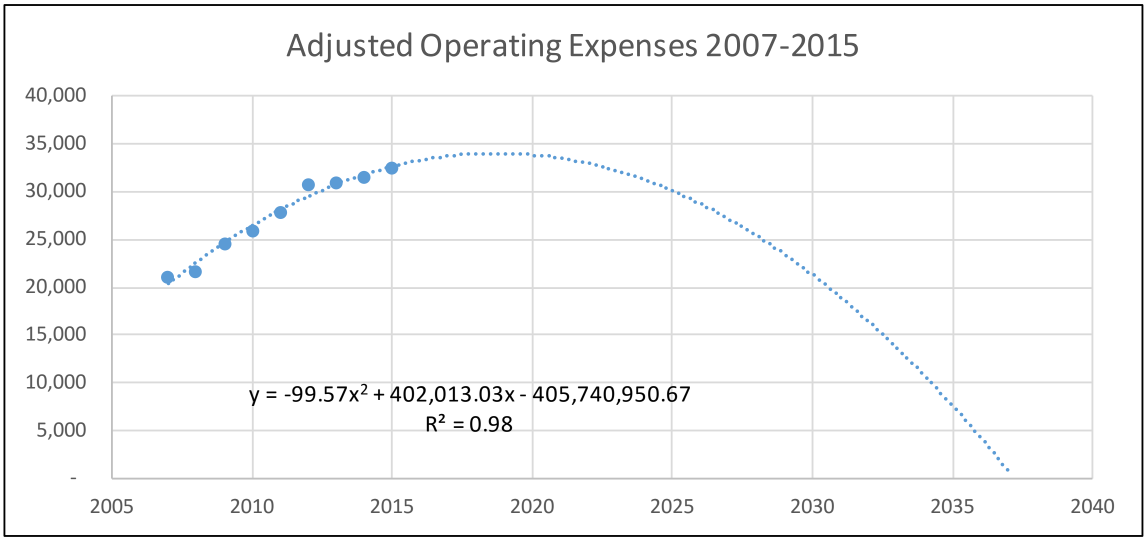
A. There are a number of reasons why it is not preferable to use a quadratic function in the Attrition Allowance method. Foremost, the use of a quadratic formula is not consistent with the calculation of growth rates in the Attrition Allowance model, as a growth rate used in this model involves linear escalation, rather than polynomial escalation. This is why the Company's model resorts to calculating the derivative of the quadratic best-fit line, rather than using the quadratic formula itself to determine the escalation applicable in the natural gas Attrition Allowance study.

In addition, based upon my review of the historical data, the relationship between changes in cost data over time is not so precise as to make the quadratic formula a meaningful predictor of future costs. Use of a quadratic function in the Attrition Allowance model would not only assume a rate of growth in a category of cost, but would also assume that the rate of growth is accelerating, or decelerating, over time. The rate at which a category of cost is expected to grow in the future is, itself, uncertain from the historical cost data, and thus, any conclusions regarding the expected change in the rate of growth over time are likely to prove even more uncertain.

Finally, a quadratic formula does not accurately describe how costs behave over time. While there might be some expectation of some sort of exponential growth in costs over time—that is, growth due to compounding—a quadratic formula is a polynomial equation that does not describe compound growth. This is probably why, for example, the quadratic formula used by the Company for O&M expense in the natural gas Attrition Allowance study predicted that O&M expenses would rapidly decline to below zero by 2037, as shown in Figure BGM-1, below.

FIGURE BGM-1

Demonstration of Inappropriateness of Quadratic Formula in Attrition Allowance Study



Q. WHY DO YOU BELIEVE IT IS MORE APPROPRIATE TO REVIEW ESCALATION RATES AT MORE GRANULAR LEVELS THAN REVIEWED BY THE COMPANY?

A. In the 2015 GRC, the Commission required that "utilities requesting an attrition adjustment demonstrate that the cause of the mismatch between revenues, rate base and expenses is not within the utility's control."[14/] Reviewing the escalation rates at major cost categories, however, does not give a good indication of why any particular expense and rate base item is increasing, and whether that increase is beyond the control of the utility. Rather, a review of more granular historical data lends itself to a better understanding of the drivers of increased costs. It also makes it more straightforward to review the reasonableness of the model, where a historical trend is not understood, not well defined, or not demonstrated to be beyond the control of the utility. Finally, a more granular analysis also allows for a case-by-case review of the costs in the attrition study to determine if a historical trend is significant enough to justify escalating the cost in

14/ 2015 GRC, Order 05 at ¶ 110.

question and whether the trend is being unnecessarily influenced by events that may not be expected in the future, such as a one-time increase in a particular category of costs.

Q. WHERE HAVE YOU PERFORMED THIS CASE-BY-CASE REVIEW?

A. In Exhibit No. BGM-5 for electric services and Exhibit No. BGM-6 for gas services, I developed a series of spreadsheets that allow for the evaluation of the entire available history for each category of costs. Based on the historical data, the models allow the selection or exclusion of any particular data points from the history to develop the escalation factor applicable to each category of cost. Each page also provides a brief narrative to document how I evaluated the escalation rate for each category of cost.

Q. WHAT GENERAL PRINCIPLES DID YOU USE WHEN EVALUATING THE ESCALATION RATES?

A. Generally speaking, more recent data is probably expected to be more representative of future conditions. Notwithstanding, because the Company's financial circumstances change over time, more recent data does not necessarily provide for the most reasonable expectation of future costs. Where a trend appears to have changed in a recent period, I typically relied on more recent data. However, there were some circumstances where the more recent data did not appear to be indicative of future results. Similarly, if a trend was consistent throughout the time series, I may have used a longer set of data points to establish the escalation rate. In addition, I also relied upon measures of statistical closeness of the data points in question (measures such as R-squared) to inform my decisions on the escalation rates, although I did not adhere to any bright-line rules for what degree of closeness was evidence of a trend. As noted above, a description of how I developed the escalation factor for each category of cost is detailed in my Attrition Allowance model exhibits.

Q. WHAT HAVE YOU GENERALLY DISCOVERED AS A RESULT OF YOUR REVIEW OF THE HISTORICAL DATA FOR ELECTRIC SERVICES?

A. As I have reviewed the electric service data in a more granular format, I encountered a number of interesting questions about the Company's claims of attrition and the degree to which its escalating expenditures can be better controlled. Firstly, I have generally been of the impression that the historical upward trends in expenditures have been driven in part by production expenditures, that is, the replacement, refurbishment, and maintenance of generation plant. For example, when the Company makes statements justifying its attrition claims based on "equipment that [was] installed many years ago (in many cases 50 to 70 years ago), when the cost of installation was very low as compared to the cost to replace them today,"[15/] my assumption has been that the reference was primarily to generation plant. Based on my review of the more granular data, however, it is clear to me that the growth in production costs (both operating expense and rate base) has been markedly flat in recent years, and thus, has had little impact on the Company's overall need for an attrition allowance. Rather, as noted in the 2015 GRC, unexplained growth in distribution-related costs continue to be a key driver of increased revenue requirement in the Attrition Allowance model.[16/]

In addition, and perhaps more surprisingly, growth in general plant has also been a key driver of revenue requirement in the Attrition Allowance model. This was surprising because general plant is typically not a type of plant that I view as being capable of driving a need for attrition. Investments in transmission and production plant can be time-sensitive and outside of the Company's control. In contrast, the need to

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15/ Exh. No. SLM-1T at 13:13-14.

16/ See 2015 GRC, Order 05 at ¶ 107.

invest in general plant is generally less time-sensitive, meaning the Company has greater discretion to control and defer those capital outlays as necessary. For example, it is probably unnecessary for a Company experiencing low load growth to invest in a new office building, and accordingly, such an investment may be better deferred.

Q. WHAT HAVE YOU GENERALLY DISCOVERED AS A RESULT OF YOUR REVIEW OF THE HISTORICAL DATA FOR GAS SERVICES?

A. With respect to gas services, growth in distribution plant is a key driver of the Attrition Allowance revenue requirement. The need for increased capital spending on gas distribution plant is better understood and defined than on the growth in distribution plant on the electric side of the Company's business. Notwithstanding, growth in general plant, as well as the associated increases to administrative and general depreciation expenses, is also a key driver of the Attrition Allowance model results. As noted, given that these outlays are more discretionary than distribution plant, it raises the question of whether growth in this category of plant is beyond the Company's control.

In addition, growth in operations expense and rate base associated with underground storage also presented some interesting historical patterns. Based on the data, these cost items remained very level, not increasing materially for some time. In 2009, however, these cost items appeared to experience an increase, perhaps corresponding to a reversionary interest held by the Company in the Jackson Prairie natural gas storage facility, and a major investment that occurred there in 2008. Based on my review, I believe it is reasonable to assume a relatively stable costs and rate base in the coming years, which is noted in Exhibit No. BGM-4.

Q. PLEASE SUMMARIZE YOUR REVIEW OF THE ESCALATION FACTORS USED IN THE ATTRITION ALLOWANCE MODEL.

A. In general, the Attrition Allowance model is best deployed by calculating and evaluating individual escalation factors for each category of cost in the Company's results of operations. Because my analysis is more detailed than the Company's, I believe it produces more informed results.

<u>b. Post-Attrition Adjustments</u>

Q. WHAT IS A POST-ATTRITION ADJUSTMENT?

A. A post-attrition adjustment is an adjustment that the Company makes to its financial results, after it has applied the escalation rates. In this filing, the Company proposes two post-attrition adjustments, the first related to a series of capital projects on the Spokane River and the second related to the Advanced Metering Infrastructure ("AMI") project. The post-attrition adjustment related to the Spokane River projects is only included in the Company's proposed Attrition Allowance study for electric services. The AMI project, however, is included in the Company's proposed Attrition Allowance study for both electric and natural gas services.

Q. PLEASE DESCRIBE THE SPOKANE RIVER AND AMI PROJECTS.

A. The Spokane River projects represent a series of capital upgrades to a number of plants along the Spokane river, the most notable of which is the rehabilitation of the Nine Mile Canyon hydro facility. These investments comprise the majority of the pro forma capital projects proposed by the Company in its Traditional revenue requirement calculation, consisting of approximately $124.9 million in capital on a total-Company basis.[17/] The AMI project represents capital associated with the deployment of new smart meter technology that is described in the Direct Testimony of Ms. Rosentrater.[18/] The AMI project also relates to the Company's accounting proposal to remove undepreciated electric meters from rate base, placing the unrecovered investment in a regulatory asset account. In the Attrition Allowance model for electric services, the Company makes a corresponding "pre-attrition" adjustment to remove retired meters from the attrition base.

Q. DO YOU AGREE THAT POST-ATTRITION ADJUSTMENTS SHOULD BE INCLUDED IN THE ATTRITION ALLOWANCE MODEL?

A. In general, no. The inclusion of separate pro forma adjustments in the Attrition Allowance methodology, above and beyond the escalation amounts, defeats the purpose of using the Attrition Allowance model to begin with. The Attrition Allowance model is designed to evaluate what the Company's results will be if the historical trends in costs are to continue into the future. If it is necessary to adjust the historical trends to reflect known and measurable pro forma adjustments, that is a reason not to use the historical trend altogether and, instead, to rely on the known and measurable standard for the entirety of revenue requirement, as done in the Traditional revenue requirement methodology.

17/ See Exh. No. KKS-4 at 1 (Representing the aggregate of the Cabinet Gorge Unit 1 Refurbishment, $14.7 million; the Post Falls South Channel Gate Replacement, $14.1 million; the Nine Mile Rehabilitation; $73.2 million; and the Little Falls Powerhouse Redevelopment, $22.9 million).

18/ See Exh. No. HLR-1T at 8:19-31:9.

Q. ARE THE PROPOSED POST-ATTRITION ADJUSTMENTS INCLUDED IN THE TRADITIONAL REVENUE REQUIREMENT METHOD?

A. Yes. To the extent that a capital project is found to satisfy the used and useful criteria, the Traditional revenue requirement methodology would already include it as a pro forma capital addition. Thus, it is not necessary to also include these capital items as post-attrition adjustments in the Attrition Allowance study. If, after considering the pro forma capital, the Traditional model produces a revenue requirement that is more favorable than the Attrition Allowance method, that is an indication that the Company is not experiencing attrition and that no attrition allowance is necessary. Including the same pro forma capital adjustments in both studies, however, would serve to double count the impact of those capital projects.

Q. DOES THE HISTORICAL DATA USED TO CALCULATE THE TRENDS INCLUDE MAJOR PROJECTS, SUCH AS THOSE PROPOSED AS POST-ATTRITION ADJUSTMENTS?

A. Yes. The historical data relied upon by the Company, however, includes major projects of a similar magnitude as those proposed as post-attrition adjustments.[19/] Thus, the escalation rates already incorporate the cost to the Company associated with large projects. If large capital projects are to be added above and beyond the escalation amounts, then it would also be necessary to normalize the historical trend data to remove the impacts of those large projects from the historical trends.

19/ See Exhibit No. BGM-9 (the Company's Response to ICNU Data Request ("DR") 166).

Q. IF THE POST-ATTRITION ADJUSTMENTS ARE TO BE INCLUDED IN THE ATTRITION ALLOWANCE STUDY, SHOULD MAJOR PROJECTS BE EXCLUDED FROM THE HISTORICAL TREND DATA?

A. Yes. If the Commission ultimately allows for the inclusion of post-attrition adjustments, then the historical data should be adjusted to eliminate the impact of the major capital projects on the escalation rates.

Q. SHOULD THE NUMBER OF YEARS OF ESCALATION ALSO BE ADJUSTED IF ANY POST-ATTRITION ADJUSTMENTS ARE TO BE APPROVED?

A. Yes. Because the post-attrition adjustments include capital that will be placed in service through the end of 2016, inclusion of post-attrition adjustments would also be a reason to reduce the number of years of escalation in the Attrition Allowance model. For instance, rather than including two years of escalation in the Attrition Allowance model, only one-half year of escalation would be necessary to arrive at mid-2017 levels due to the fact that the model already includes capital through the end of 2016.

Q. HAVE YOU MADE AN ADJUSTMENT FOR PROJECT COMPASS IN THE CURRENT PROCEEDING?

A. Yes. Because Project Compass was explicitly considered to be extraordinary in the 2015 GRC, outside of the historical trends, it should also be removed from the historical trends calculated in this proceeding. As can be seen Exhibit No. BGM-3, I have made an adjustment to reflect the removal of Project Compass from the historical trend amounts used to calculate the escalation rates for intangible plant in the electric Attrition Allowance study.

Q. IS IT REASONABLE TO EXCLUDE THE POST-ATTRITION ADJUSTMENT, EVEN IF THE ESCALATION AMOUNT IS LESS THAN THE AMOUNT RELATED TO THE PRO FORMA PROJECT?

A. Yes. Ms. Andrews suggests that, absent the application of these post-attrition adjustments, the escalation factors will produce a level of plant that is less than the plant determined under the known and measurable standard.[20/] As noted above, if the known and measurable standard produces a more favorable result than the reliance on historical trends, then the Traditional revenue requirement method should be used. Allowing the Company to use trends for some categories of costs, but pro forma adjustments for others, would be one-sided because the pro forma standard applied to all categories of costs would potentially produce a lower revenue requirement. If pro forma adjustments are to be made in addition to the historical trends, it allows the Company to cherry-pick those items that it knows will increase by an amount greater than the historical trends, while ignoring those items that will increase by an amount less than the historical trends. This one-sided approach should be avoided as it is unfair to ratepayers.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATION WITH RESPECT TO POST-ATTRITION ADJUSTMENTS.

A. Allowing the Company to make additional pro forma adjustments, above and beyond the historical trend amounts, would be unfair and one-sided. In my models, I have eliminated the post-attrition adjustments related to the Spokane River Projects and AMI. For the same reason, I have also eliminated the pre-attrition adjustment for AMI, discussed in the following sub-section.

[20/] See Exh. No. EMA-1T at 27:2-29:2.

c. Attrition Base

Q. HOW HAVE YOU DEVELOPED THE ATTRITION BASE?

A. With the exception of the regulatory amortization amounts and removal of power and fuel supply costs, my model makes no adjustments to the Company's Commission basis results of operations for the test period to establish the attrition base. I viewed this to be a simpler way to perform the Attrition Allowance study, rather than making the series of adjustments proposed by the Company.

Q. HOW IS YOUR ATTRITION BASE DIFFERENT THAN THE COMPANY'S MODEL?

A. In addition to adjustments for regulatory amortizations and removal of power and fuel supply costs, the Company made two pre-attrition adjustments to the Commission basis results of operations for the test period to arrive at the attrition base. First, the Company made an adjustment to remove retired meters pursuant to the AMI project. Second, the Company adds capital placed into service through the end of 2015. That is, the Company added capital placed into service in the fourth quarter of 2015. In my model, I have excluded both of these adjustments.

Q. WHY HAVE YOU EXCLUDED BOTH OF THESE ADJUSTMENTS?

A. The AMI adjustment is unnecessary because I have excluded the AMI post-attrition adjustment from the model. Both ICNU and NWIGU generally disagree that the Company should proceed with the AMI project, and accordingly, I have removed the impact of the project from revenue requirement. In addition, I viewed it to be unnecessary to add the capital placed into service in the fourth quarter of 2015, as that would create unnecessary complication to the model. I viewed it to be relatively important to have a consistent set of financial results for the attrition base, rather than having capital based on calendar year 2015 and operating expenses based on the year ending September 2015. The Company had the option of waiting until the calendar year 2015 results were available to incorporate them into its filing, as its proposed test period, but did not do so. Therefore, I think it is important that the analysis of the Company's filing be confined to a single test period, rather than mismatching various components of the Company's results.

Q. HOW DOES YOUR MODEL ACCOUNT FOR CAPITAL EXPENDED IN THE FOURTH QUARTER OF 2015?

A. Rather than escalating the attrition base for two calendar years, I adjusted the model to allow for two years and one quarter worth of escalation. That is, I escalated the attrition base by 2 1/4 years to account for capital expended in the fourth quarter of 2015, rather than escalating the attrition base by 2 years, as done in the Company's model. This is a cleaner way to approach the Attrition Allowance model, limiting the number of adjustments that are necessary to calculate the final Attrition Allowance revenue requirement.

Q. DOES THIS ADJUSTMENT ALSO REMOVE PLANT HELD FOR FUTURE USE?

A. Yes. As discussed in the Direct Testimony of Ms. Andrews, the Company's proposed attrition base includes plant held for future use, which was embedded in the adjustment related to capital for the fourth quarter of 2015.[21/] As discussed below, the Company's proposal to include plant held for future use in revenue requirement does not align well with Commission practices. By eliminating the adjustment related to the capital expended in the fourth quarter of 2015, my adjustment also removes the impact of plant

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21/ Exh. No. EMA-1T at 43:8-9.

held for future use in the electric Attrition Allowance study. Irrespective of how the Commission ultimately decides to account for capital expended in the fourth quarter of 2015 in the attrition base, I recommend that the plant held for future use be removed from the electric Attrition Allowance model.

Q. HAVE YOU MADE ANY OTHER ADJUSTMENTS TO THE ATTRITION BASE?

A. Yes. Pursuant to the discussion below on director fees, I have adjusted the Company's attrition base results of operations to be consistent with the Commission's Order in the 2015 GRC.[22/] In its Order, the Commission required the Company to split those fees between ratepayers and shareholders 50%/50%, rather than the Company's use of a 90%/10% split in its attrition base.[23/]

<u>d. Used and Useful Review</u>

Q. WHAT IS THE FINAL ADJUSTMENT THAT YOU HAVE MADE TO THE ATTRITION ALLOWANCE STUDY?

A. Pursuant to RCW 80.04.250, the Commission has traditionally only allowed, in rates, plant which has been demonstrated to be used and useful to customers in Washington state. The Attrition Allowance model, in applying escalation rates to historical rate base amounts, however, does not necessarily evaluate what level of rate base is used and useful. In contrast, the Traditional model explicitly evaluates the level of plant that is used and useful pursuant to the statute. The used and useful standard and the Attrition Allowance model, however, are not necessarily mutually exclusive, as the attrition allowance model can be deployed in a manner that takes the used and useful standard into

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22/ 2015 GRC, Order 05 ¶ 220.

23/ Exh. No. BGM-9 (the Company's Response to ICNU DR 83).

consideration. Thus, as a final step in my model, I make an adjustment to rate base that caps the escalation amounts based on the level of plant determined to be used and useful by the Commission.

Q. DOES THIS ELIMINATE THE PURPOSE OF THE ATTRITION ALLOWANCE METHOD?

A. No. The application of escalation rates to net plant and depreciation expense has the potential to result in plant values that are either higher or lower than the amounts determined based on the application of the used and useful standard under the Traditional method. Accordingly, the proposed caps would only apply to the extent that the used and useful plant amounts are lower than the amounts determined through the application of escalation factors.

Q. HOW DID YOU DETERMINE THE LEVEL OF USED AND USEFUL PLANT TO BE USED IN THE ATTRITION ALLOWANCE MODEL?

A. The cap on rate base is based on the plant that I found to be used and useful in my review of pro forma capital pursuant to the Traditional revenue requirement methodology. That evaluation is discussed in the section of my testimony devoted to the Traditional revenue requirement method, below.

Q. PLEASE SUMMARIZE YOUR TESTIMONY ON THE ATTRITION ALLOWANCE METHOD.

A. I have developed an Attrition Allowance model that allows for a more informed evaluation of the escalation factors, by reviewing historical trends at a more granular level than that proposed by the Company. In addition, I propose to eliminate the pro forma, post-attrition adjustments from the Attrition Allowance model, as those adjustments are more properly reviewed in the context of the Traditional Revenue requirement methodology. Finally, my model demonstrates that the application of the used and useful standard of RCW 80.04.250 is not mutually exclusive with the Attrition Allowance model and can be incorporated into the Attrition Allowance ratemaking framework adopted by the Commission. After making these changes, my model demonstrates that even considering the Attrition Allowance methodology, the Company is not justified in increasing its rates at this time.

IV. TRADITIONAL METHOD

Q. WHAT DID THE COMPANY FILE WITH RESPECT TO THE COMMISSION'S TRADITIONAL REVENUE REQUIREMENT METHOD?

A. Table 1, of the Direct Testimony of Ms. Smith, details the pro forma revenue requirement that the Company proposes based upon the Traditional method.[24/] As noted in the Table, the Traditional revenue requirement calculations included in the Company's initial filing recommended a revenue requirement increase of $11.8 million for electric services and a revenue requirement reduction of $1.2 million for natural gas services.[25/] These amounts are substantially less than the revenue requirement increase of $38.6 million increase for electric services and $4.4 million for natural gas services calculated using the Company's proposed Attrition Allowance model.[26/] Exhibit No. JSS-2 and Exhibit No. JSS-3 detail the restating and pro forma adjustments relied upon by the Company to arrive at this Traditional revenue requirement, although the exhibits also include pro forma "cross check" adjustments, which have historically not been reflected in revenue requirement under the Traditional method.

24/ Exh. No. JSS-1T at 6, Table 1.

25/ Id.

26/ Id.

Q. WHAT WAS THE NATURE OF YOUR REVIEW OF THE COMPANY'S TRADITIONAL REVENUE REQUIREMENT CALCULATIONS?

A. Because the Traditional method often results in a revenue requirement that is less than that calculated using the Attrition Allowance method, the results of the Traditional revenue requirement method are often irrelevant under the Commission's recently adopted paradigm. Accordingly, my review of the Company's calculation of the Traditional methodology has been performed at a relatively high level.

Q. WHAT ARE THE RESULTS OF YOUR REVIEW OF THE TRADITIONAL MODEL?

A. Tables BGM-4 and BGM-5 detail my adjustments to the Company's Traditional revenue requirement model calculations for electric and gas services, respectively. As can be seen, these calculations support a revenue requirement reduction of $5.4 million for electric services and $5.2 million for gas services. In addition, I have prepared Exhibit No. BGM-5 and Exhibit No. BGM-6 detailing the rate base, net operating income and revenue requirement impacts of each restating and pro forma adjustment reflected in these revenue requirement calculations, starting with the Company's as-booked results of operations.

TABLE BGM-3

Traditional Washington Revenue Requirement, Electric Services ($000)

1	**Company Filing**	**11,843**
2	**Impact of Contested Adjustments:**	
3	Cost of Capital	(8,878)
4	Major Pro Forma Capital (Adj. 3.10)	(3,148)
5	Plant Held for Future Use (Adj. 1.04)	(548)
6	AMI Meter Deferral (Adj. 3.07)	(1,209)
7	Labor Expense (Adj. 3.02)	(881)
8	Director Fees (Adj. 2.12)	(347)
9	Power Costs (Adj. 3.00 & Adj. 3.01)	(2,258)
10	**Total Adjustments**	**(17,269)**
11	**Adjusted**	**(5,426)**

TABLE BGM-4

Traditional Washington Revenue Requirement, Gas Services ($000)

1	**Company Filing**	**(1,151)**
2	**Impact of Contested Adjustments:**	
3	Cost of Capital	(1,802)
4	Major Pro Forma Capital (Adj. 3.09)	(1,926)
5	Labor Expense (Adj. 3.00)	(262)
6	Director Fees (Adj. 2.12)	(100)
7	**Total Adjustments**	**(4,090)**
8	**Adjusted**	**(5,241)**

a. Major Pro Forma Plant Additions (Electric Adj. 3.10; Natural Gas Adj. 3.09)

Q. WHAT ARE THE MAJOR PLANT ADDITIONS THAT THE COMPANY PROPOSES TO BE REFLECTED IN REVENUE REQUIREMENT?

A. In Exhibit No. KKS-5, the Company has detailed 12 projects as major "Modified Test Year Pro Forma Projects," which it requests the Commission to consider for inclusion in rate base as major pro forma plant additions under the Traditional method. The 12 projects are detailed in Table BGM-5, below. Table BGM-5 also details the actual amount of capital placed into service through May 2015, the most recent actual plant data provided by the Company.

TABLE BGM-5
List of Pro Forma Capital Projects and Actual Capital Placed into Service
(Total-Company, $000)

ln	Project	Filed Per Exh. No. KKS-4	Actual May 2015	
1	Colstrip Thermal Capital	12,292	2,633	
2	Cabinet Gorge Unit 1 Refurbishment	14,702	16,218	
3	Hydro - Post Falls South Channel Gate Replacement	14,092	14,714	
4	Hydro - Nine Mile Rehab	73,193	67,649	*
5	Hydro - Little Falls Powerhouse Redevelopment	22,892	-	
6	New Downtown Netwk Bldg	9,600	3,670	
7	COF Long-Term Restructuring Plan	9,550	6,181	
8	Aldyl A Replacement	18,885	5,509	
9	Gas Isolated Steel Replacement Program	3,550	446	
10	Gas Non-Revenue Program	6,000	2,787	
11	Technology Refresh to Sustain Business Process	18,001	6,165	
12	Noxon Switchyard Rebuild	11,500	14,523	
13	**Estimate through July 2016*			

Q. WHAT IS YOUR UNDERSTANDING OF THE COMMISSION'S POLICY ON MAJOR PRO FORMA CAPITAL ADDITIONS?

A. The Commission's policy on major pro forma capital additions has been established over a long series of contested proceedings, extending back several decades. In the Pacific

Power 2014 general rate case, the Commission reaffirmed its policy, stating that its "long-standing practice is to consider post-test-year capital additions on a case-by-case basis following the used and useful and known and measurable standards while exercising the considerable discretion these standards allow in the context of individual cases."[27/] According to the Commission, "[t]his approach provides the Commission with flexibility when evaluating relevant factors without being confined by 'too rigid an approach' through a consistent, bright-line standard."[28/]

Q. WHAT HAVE UTILITIES TYPICALLY BEEN REQUIRED TO DEMONSTRATE TO INCLUDE POST-TEST-YEAR CAPITAL IN RATES?

A. In order to be considered under the Commission's standard, the Commission has historically required a utility to meet its burden of proof to demonstrate that the pro forma plant is "used and useful for service in this state."[29/] Pursuant to this burden of proof, the Commission has historically required the utility to demonstrate "'quantifiable' benefits to ratepayers in Washington,"[30/] in order for a major pro forma addition to be includible in rates.

Q. HAS THE COMMISSION TYPICALLY APPROVED SMALL PROJECTS FOR INCLUSION ON A POST-TEST-YEAR BASIS?

A. While it has not adopted a formal bright-line standard to determine whether a plant addition rises to the level of being a "major" plant addition, and thus, eligible to be included in rates on a post-test-year basis, the Commission has typically not considered small or routine capital additions for inclusion in rates on a post-test-year basis, noting in

27/ WUTC v. Pacific Power, Dockets UE-140762 *et al.*, Order 08 at ¶ 165 (Mar. 25, 2015) (citing WUTC v. PacifiCorp, Docket UE-130043, Order 05 at ¶ 198 (Dec. 4, 2013)).

28/ Id. (citing Docket UE-130043, Order 05 at ¶¶ 198-199).

29/ Id. at ¶ 166 (citing WUTC v. PacifiCorp, Docket UE-050684, Order 04 ¶ 49 (Apr. 17, 2006)).

30/ Id. (citing Docket UE-050684, Order 04 at ¶ 51).

the Pacific Power 2014 general rate case that "the relative size of many of the Company's proposed plant additions in this case falls short of any reasonable definition of 'major.'"[31/]

Q. HOW HAVE YOU EVALUATED THE 12 PROJECTS DETAILED ABOVE?

A. For purposes of this proceeding, I have included capital which the Company has demonstrated to have actually been placed into service. The most recent data provided by the Company in response to ICNU Data Request 163, to which the Company responded on July 29, 2016, included capital placed into service through May 2016. Thus, my revenue requirement calculation only included the actual capital demonstrated to have been placed into service through May 2016, with one exception.

Q. WHAT WAS THE EXCEPTION?

A. The one exception was the Nine Mile Rehabilitation project. This project was the largest of all the major pro forma capital additions requested by the Company. While the bulk of this project had not been placed into service by May of 2016, my understanding is that the majority of the capital related to the project was placed into service in July 2016. While the ultimate amount of capital placed into service is unknown at this time, I have included the Company's projected capital through July 2016.

Q. DO YOU HAVE ANY OTHER CONCERNS WITH THE LIST OF PROJECTS DETAILED ABOVE?

A. Yes. In my view, several of the projects listed above are not best categorized as major pro forma plant additions. While I am not contesting their inclusion at this time, projects such as Colstrip Thermal Capital and Technology Refresh to Sustain Business Process

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[31/] Id. at ¶ 170.

are probably best considered amongst the Company's other ordinary capital spending programs and should not be afforded extraordinary ratemaking treatment as a major pro forma plant addition. These sorts of projects are "blanket projects" that represent a category of capital spending that consists of many small projects, but for purposes of reporting, the small projects are aggregated into a single project. These blanket capital items are ongoing in nature, and accordingly, they may not be best evaluated in the context of a major pro forma plant addition.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION RELATED TO MAJOR PRO FORMA PLANT ADDITIONS?

A. For purposes of calculating my adjustment, I used the Company's pro forma workpapers and pro-rated the rate base and depreciation expense associated with each category of plant based on the percentage of actual capital placed in service relative to the amount included in the Company's initial filing. The impact of this adjustment is an approximate $3.1 million reduction to electric revenue requirement and an approximate $1.9 million reduction to gas revenue requirement, relative to the Company's filing.

b. Plant Held for Future Use (Electric Adj. 1.04)

Q. HAS THE COMPANY PROPOSED TO INCLUDE PLANT HELD FOR USE IN REVENUE REQUIREMENT?

A. Yes. As discussed at in the Direct Testimony of Ms. Smith, the Company includes certain plant held for future use in electric revenue requirement.[32/] Specifically, the Company proposes to include several parcels of land for future substations and for a

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[32/] Exh. No. JSS-1T at 19:7-20-:19.

potential future generating resource.[33/] As discussed by Ms. Smith, "[s]ecuring the property in advance at a reasonable cost ensures that the property is available."[34/]

Q. WHAT IS THE COMMISSION'S TRADITIONAL STANDARD FOR PLANT HELD FOR FUTURE USE?

A. In 1993, the Commission issued a relevant determination in a rate case involving the predecessor of Puget Sound Energy.[35/] In that proceeding, the Commission adopted several Staff criteria for determining when plant held for future use should be reflected in rate base.[36/] Pertinent to this proceeding is the criterion that plant held for future use be removed "which have no specific dates on which they are expected to be placed in service."[37/]

Q. HAS THE COMPANY IDENTIFIED SPECIFIC DATES ON WHICH THE IDENTIFIED PLANT HELD FOR FUTURE USE WILL BE PLACED IN SERVICE?

A. No. Accordingly, it would be more consistent with the Commission's past practice to remove the identified plant held for future use from rate base.

Q. AS A MATTER OF POLICY SHOULD THE PLANT HELD FOR FUTURE USE BE REMOVED?

A. Yes. In addition to the precedent identified above, by its definition, plant held for future is probably not best characterized as meeting the used and useful criteria, and accordingly, should be removed from rate base. In this case, the facilities for which the land was purchased have not necessarily been identified in the Company's Integrated

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33/ Id. at 20:5-9.

34/ Id. at 20:15-16.

35/ WUTC vs. Puget Sound Power & Light Company, Dockets UE-921262 *et al.*, Eleventh Supplemental Order (Sept. 21, 1993).

36/ Id. at 89-91.

37/ Id. at 89.

Resource Plan, nor have ratepayers had an opportunity to review whether the facilities will ultimately be necessary for utility service. With respect to the parcel of land identified for a future generating resource, placing that property into rate base poses additional ratepayer concerns, as it presumes the outcome of a future utility resource procurement process will be utility ownership.

Q. WHAT IS THE IMPACT OF THIS RECOMMENDATION?

A. Removal of plant held for future use results in a reduction to electric rate base of approximately $5.4 million, Washington-allocated. The revenue requirement impact of removing plant held for future use is a reduction of approximately $0.6 million for Washington electric services.

c. AMI Meter Deferral (Electric Adj. 3.07)

Q. WHAT IS THE COMPANY'S PROPOSAL WITH RESPECT TO THE AMI METER REPLACEMENT PROGRAM?

A. As discussed in the Direct Testimony of Ms. Rosentrater, "[t]he Washington Advanced Metering Project (Project) will deploy advanced metering to approximately 253,000 electric, and 155,000 natural gas customers encompassing all of Avista's Washington service area."[38/] This would require the Company to replace existing electric meters that are in working order and that have yet to be fully depreciated, at great expense to ratepayers. Ms. Smith described the Company's proposed revenue requirement impact of this proposal, which would rely on regulatory accounting to provide the Company with continued recovery of the electric meters that would be removed from service over a fifteen-year period.[39/] The net impact of this treatment under the Traditional method is an

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38/ Exh. No. HLR-1T at 9:7-9.

39/ Exh. No. JSS-1T at 36:15-37:6.

approximate $1.2 million increase to electric revenue requirement. For gas services, the Company does not include a pro forma adjustment for the AMI meter deferral program because the program does not require existing gas meters to be retired, but, rather, requires the installation of a small module on the existing meters.[40] In addition, the Company will be required to make substantial investments in both electric and gas services in the future. These investments are memorialized by the Company as "cross check" adjustments that are not included in revenue requirement under the Traditional method. These investments are also included in the Company's Attrition Allowance study as post-attrition adjustments, as noted above.

Q. WILL THE AMI PROJECT BENEFIT RATEPAYERS?

A. The Company claims that the AMI program will produce benefits to ratepayers,[41] yet the majority of these benefits can generally be considered to be "soft" benefits—that is, benefits which cannot be easily quantified and may ultimately have no impact on reducing future costs to ratepayers. For example, one of the categories of benefits cited by the Company referred to the "Meter Salvage & Local Economy Jobs," and assigned a value to the "estimated positive impact of the Project on local employment [] based on the forecasted effect of adding 13 direct jobs through the deployment period and the wage value expected for these positions."[42] This value, however, directly contradicts the fact that the program will require the Company to terminate the 41 meter readers,[43] eliminating any positive impact on local employment that the program might have. In

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40/ Exh. No. HLR-1T at 13:13-15.

41/ Id. at 18:11-19:30.

42/ See the Workpaper of Ms. Rosentrater titled BAMI Business Case Benefits - Meter Salvage_Local Economy.

43/ See the Workpaper of Ms. Rosentrater titled AAMI Business Case Benefits - Manual Meter Reading.

addition, as was recently noted with the severe over-runs associated with Project Compass,[44/] it is often difficult to predict with certainty the cost outcome of complicated information technology projects, even considering the inclusion of budget contingencies in the Company's analysis.

Q. GIVEN THESE UNCERTAINTIES, DO ICNU AND NWIGU SUPPORT THE COMPANY'S AMI PROPOSAL?

A. No. A utility such as the Company that is struggling with low load growth should not be making unnecessary investments in new meters. The costs and benefits of such a program are uncertain, imposing risks that large customers are not comfortable taking in their service rates. In addition, most large customers already have smart meters installed at their facilities, so the benefits to large customers are even more uncertain. This is one aspect of the Company's rate base of which the Company is in direct control. It has the ability to defer this investment until such a time that the economic conditions in its service area no longer place it in a position of requiring an attrition allowance. I recommend that the Commission reject the Company's AMI meter replacement proposal and the associated deferral reflected in the Company's Traditional revenue requirement calculations for electric services.

d. Labor Expense (Electric Adj. 3.02, Natural Gas Adj. 3.00)

Q. WHAT ADJUSTMENT DO YOU PROPOSE IN RELATION TO LABOR COSTS?

A. As discussed in the 2015 GRC, the Company uses an imprecise model for calculating the pro forma adjustment related to its labor expense.[45/] Specifically, the Company's model

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44/ See 2015 GRC, Order 05 at ¶¶ 156-174.

45/ Id. at ¶ 207.

does not consider the fact that a large portion of its labor expenditures is capitalized each year and that the capitalized portion changes from year to year.

Q. HOW DOES THE COMPANY'S MODEL CALCULATE THE PRO FORMA ADJUSTMENT FOR LABOR EXPENSE?

A. The Company's model simply escalates the test period expense by a percentage equal to its expected wage increases in the rate period. It does not consider the fact that the capitalized portion of labor expenditures may vary from year to year.

Q. HOW HAS THE CAPITALIZED PORTION OF LABOR EXPENDITURES CHANGED IN RECENT YEARS?

A. The capitalized portion of labor expenditures have been increasing in recent years. Shown in Table BGM-6, below, is the trajectory of the capitalized labor expenditures over the period 2012 through 2015.

TABLE BGM-6
<u>Capitalized Labor Expense 2012 – 2015</u>[46/]

ln	Year	Percent Capitalized	Annual Increase
1	2012	32%	
2	2013	35%	3.0%
3	2014	34%	-1.0%
4	2015	36%	2.0%
5		Average	1.3%

46/ See Exh. No. BGM-9 (The Company's Response to ICNU DR 170).

Q. HOW HAS THE INCREASING PORTION OF CAPITALIZED LABOR IMPACTED THE ACCURACY OF COMPANY'S PRO FORMA CALCULATIONS IN PRIOR CASES?

A. Because the capitalized portion has been increasing, the Company's practice of escalating test period labor expenses based on the overall wage increase likely has overstated labor expense in prior cases. While wages may have gone up, the overall expense likely did not increase by the same amount because a greater portion of the expenditures were being capitalized. Thus, by not accounting for the increased capitalization, the data suggests that the Company has been over-recovering its labor costs.

Q. WHAT IS YOUR RECOMMENDATION FOR THIS PROCEEDING?

A. Absent a robust Full-Time-Equivalent ("FTE") labor model, it is difficult to predict how changing levels of capitalization might impact labor expense precisely in the rate period. Given the large increases in capital expenditures proposed by the Company, however, my expectation is that the capitalized portion of labor expense will continue to increase. Accordingly, I recommend assuming an approximate 1.3% increase to the overall proportion of labor expense that will be capitalized in the rate period. That is, I recommend assuming that that the capitalized portion of labor expense will increase to 37.3% in the rate period.

Q. WHAT IS THE IMPACT OF THIS RECOMMENDATION?

A. This recommendation has the effect of reducing the Company's pro forma labor expense by 2.1%.[47/] In turn, this has the effect of reducing the Company's pro-forma labor adjustment by $0.9 million for electric services and $0.3 million for natural gas services.

[47/] 1.3% / (1 – 37.3%). This formula represents the percentage increase in the non-capitalize portion of labor expense.

e. Director Fees (Electric Adj. 2.12; Natural Gas Adj. 2.12)

Q. WHAT DID THE COMMISSION ORDER WITH RESPECT TO DIRECTOR FEES IN THE 2015 GRC?

A. In the 2015 GRC, the Commission noted that "Avista only removed 3 percent of the director fee expenses, while our practice is to allow the Company recovery of 50 percent of director fees from ratepayers."[48/]

Q. DID THE COMPANY COMPLY WITH THE COMMISSION'S DECISION IN THIS PROCEEDING?

A. No. The Company continues to remove only 3% of director fees from its results as a restating adjustment.[49/]

Q. WHAT WAS THE COMPANY'S BASIS FOR CONTINUING TO INCLUDE SUCH A LARGE PORTION OF DIRECTOR FEES IN RATES?

A. The Company claims that "in the aggregate, approximately 97% of the Directors' time is dedicated to utility matters, and approximately 3% to non-utility."[50/] Because of the amount of time spent on utility matters, the Company believes it is justified in including a major portion of its director fees in rates.

Q. DO YOU AGREE?

A. No. The issue is not the amount of time that the directors spend on utility matters, but, rather, whether the time spent was for the benefit of ratepayers or shareholders. By assuming a 50%/50% split for director fees, the assumption is that the directors' time benefits both shareholders and ratepayers equally.

48/ 2015 GRC, Order 05 at ¶ 220.

49/ See Exh. No. BGM-9 (the Company's Response to ICNU DR 83).

50/ Exh. No. JSS-1T at 25:5-7.

Q. WHAT IS THE IMPACT OF YOUR ADJUSTMENT?

A. Applying a 50%/50% split for director fees results in an approximate $0.3 million reduction to net operating income for electric services and an approximate $0.1 million reduction to net operating income for gas services.

V. POWER COSTS (ADJ. 3.00)

Q. PLEASE PROVIDE AN OVERVIEW OF HOW THE COMPANY CALCULATES POWER COSTS?

A. The calculation of power costs is detailed in the Direct Testimony of Mr. Johnson.[51/] For purposes of determining the cost of fuel for thermal generation, the cost of power purchases and sales revenues, Mr. Johnson relies on the analysis performed by Mr. Kalich using the AURORAxmp model.[52/]

Q. HOW DOES THE AURORA MODEL CALCULATE POWER COSTS?

A. The AURORA model is a modeling tool used primarily to forecast power market prices. It evaluates the loads and resources available to the entire Western Interconnection and uses the marginal cost of generation at specified market hubs to forecast the market clearing price. These market prices, along with the assumed dispatch of the Company's resources, are then placed into a portfolio model, which determines the volume and cost of system balancing purchases and sales used in the power cost calculations of Mr. Johnson. The portfolio model is a simplistic model that simply looks at the Company's assumed load and resource balance, and calculates a sale if the Company is long and a purchase if the Company is short.

51/ See Exh. No. WGJ-1T.

52/ Id. at 2:9-13

Q. HOW ACCURATE HAS THE AURORA MODEL BEEN?

A. As evidenced by the balances that have accumulated in the Energy Recovery Mechanism ("ERM") and the Company's recurrent proposals to use funds accrued to the ERM to offset base rate increases, the AURORA model probably tends to overstate power costs.

Q. WHY IN YOUR OPINION DOES THE AURORA MODEL OVERSTATE POWER COSTS?

A. It seems to be an issue with how the AURORA model calculates sales and purchases. In Exhibit No. WGJ-2, it can be noted on lines 1-2 and 57-58 that the sales and purchases modeled in the AURORA model are substantially less than the levels made in actual operations. The sales revenues calculated in the AURORA model, for example, were $39.4 million, compared to actual sales revenues of $105.6 million.[53/] That is, the actual sales volumes were 268% greater than the amount calculated in AURORA. These large differences may be related to the simplistic portfolio model used by the AURORA model, as well as the fact that the dispatch of the Company's resources was calculated for the entire Western Interconnection, not specifically for the Company's service area.

In addition, the Company's modeling includes a number of "results driven" assumptions, which, as explained below, are arbitrary and put in place only for the purpose of increasing the modeled dispatch costs.

Q. WHAT POWER COST ADJUSTMENTS DO YOU PROPOSE?

A. Table BGM-7 details the power cost adjustments that I support in this proceeding.

53/ Exh. No. WGJ-2 at 2:57-58.

TABLE BGM-7
Impact of Power Cost Adjustments, Washington-Allocated ($000)

1	BPA Rates	(580)
2	Low-Voltage Use-of-Facilities	(473)
3	OATT Ancillary Service Rates	(429)
4	Owned Hydro Variable O&M	(267)
5	Bidding Adder Assumption	(404)
6	**Total Adjustments**	**(2,153)**

Q. HOW HAVE YOU PERFORMED THESE ADJUSTMENTS?

A. The Company's modeling performs a stochastic power calculation using historical hydro and wind conditions over the period 1929 through 2008. Due to this complexity, a full power cost run can take a substantial amount of time to resolve. Accordingly, for simplicity purposes, where a power cost run was necessary, my adjustment calculations were performed above using hydro and wind conditions for 1938. I selected 1938, because it represented the approximate median conditions year for the Spokane River system, which I expected to produce adjustment results in alignment with what would be calculated based upon a full stochastic model run.

a. Bonneville Power Administration ("BPA") Rates

Q. WHAT IS YOUR RECOMMENDATION RELATED TO BPA TRANSMISSION RATES?

A. The Company has proposed to increase its BPA wheeling costs beginning in October 2017, corresponding to the rate effective date of BPA's upcoming BP-18 power and transmission rate case.[54/] The BP-18 rate case is expected to be filed in November of 2016, with a final record of decision to be issued sometime in the summer of 2017. At

54/ Exhibit No. WGJ-1T at 7:16-21; See Exh. No. BGM-9 (the Company's Response to Staff DR 146).

this point, however, it is too uncertain to determine what the outcome of the BP-18 rate case will be on the Company's transmission rates. Accordingly, I recommend excluding the Company's provision for a BPA transmission rate increase in the fourth quarter of the rate period.

Q. DID THE COMPANY INCLUDE ANY OTHER TRANSMISSION RATE INCREASES IN ITS WHEELING COSTS THAT WERE NOT KNOWN AND MEASURABLE?

A. Yes. In response to Staff Data Request 146, the Company detailed a number of other wheeling contracts where the Company proposed to apply escalation that is not known and measurable. I also propose to remove this escalation from the Company's pro forma power cost calculations.

Q. WHAT IS THE IMPACT OF THIS ADJUSTMENT?

A. The impact of this adjustment is an approximate $0.6 million reduction to the Company's pro forma power costs on a Washington-allocated basis.

b. Low-Voltage Use-of-Facilities Charges

Q. WHAT ISSUE HAVE YOU IDENTIFIED WITH RESPECT TO THE COMPANY'S LOW-VOLTAGE USE-OF-FACILITIES RATES?

A. On February 23, 2016, the Company filed with the Federal Energy Regulatory Commission ("FERC") a request to increase the rates associated with low-voltage use-of-facilities charges that it receives in connection with its Network Integration Transmission Service Agreements ("NITSAs") with BPA. A selection from the Company's filing has been included as Exhibit No. BGM-7, along with a slide from a BPA presentation that calculated the revenue impact of this filing.

Q. DID THE COMPANY INCLUDE THE ADDITIONAL REVENUE FROM THIS RATE INCREASE IN ITS FILING?

A. No.

Q. WHAT IS THE IMPACT OF THIS RATE INCREASE?

A. According to BPA, the proposed NITSA rate increase will result in an additional $0.7 million in revenues to the Company. On a Washington-allocated basis, this amounts to approximately $0.5 million in revenues.

Q. DO YOU PROPOSE TO REFLECT THIS RATE INCREASE IN THE COMPANY'S PRO FORMA REVENUE REQUIREMENT?

A. Yes. In addition, while the power costs reflected in Mr. Johnson's testimony do not include wheeling revenues, the power supply costs, as used in the Attrition Allowance model, do include wheeling revenues. Accordingly, it is necessary to adjust the revenue requirement calculated under both the Traditional method and the Attrition Allowance method for this additional revenue.

c. Open Access Transmission Tariff Ancillary Service Rates

Q. WHAT ISSUE HAVE YOU IDENTIFIED WITH RESPECT TO THE COMPANY'S OPEN ACCESS TRANSMISSION TARIFF ANCILLARY SERVICE RATES?

A. On June 30, 2016, the Company filed with FERC to increase its Open Access Transmission Tariff ancillary service rates, Schedules 3, 3A, 5 and 6. This filing reflected an increase in the cost of capacity assigned to these ancillary service rates. A selection from the Company's filing can be found in Exhibit No. BGM-8.

Q. DID THE COMPANY INCLUDE THE ADDITIONAL REVENUE FROM THIS RATE INCREASE IN ITS FILING?

A. No.

Q. WHAT IS THE REVENUE IMPACT OF THIS RATE INCREASE?

A. As detailed in Exhibit No. BGM-8, the Company's filing indicated that the rate increase would result in an approximate $0.6 million increase in total-Company revenues. This amounts to approximately $0.4 million in additional revenues on a Washington-allocated basis.

Q. SHOULD THIS ADDITIONAL REVENUE BE APPLIED TO BOTH THE ATTRITION ALLOWANCE AND TRADITIONAL REVENUE REQUIREMENT MODELS?

A. Yes. Similar to the adjustment related to the Low-Voltage Use-of-Facilities Charges, this additional revenue should be applied against both the Traditional and Attrition Allowance revenue requirement calculations.

d. Owned Hydro Variable O&M

Q. WHAT IS THE ISSUE THAT YOU HAVE IDENTIFIED WITH RESPECT TO OWNED HYDRO VARIABLE O&M?

A. In AURORA, the Company models its owned hydro resource including a (-)$[redacted]/MWh variable O&M charge. I identified this charge by reviewing the "resource table" in the AURORA model provided with the Company's initial filing. This assumption, however, is not consistent with the actual variable O&M associated with hydro resources. Rather, the actual variable O&M associated with hydro resources is typically zero, as it does not require much in the way of operational expense in order to increase or reduce the amount of water flowing through a hydroelectric turbine.

Q. WHY DOES THE COMPANY INCLUDE THIS NEGATIVE O&M CHARGE IN AURORA?

A. When asked to provide support for the inputs for variable operations and maintenance expenses for the Company's owned hydro resources, the Company denied that it included these charges in the AURORA model, stating, "Avista does not include a variable operations and maintenance amount in the AURORA model for owned hydro resources."[55/]

Q. WHAT IS YOUR UNDERSTANDING OF THE COMPANY'S REASONING FOR INCLUDING THE (-)$[redacted]/MWH O&M CHARGE FOR HYDRO RESOURCES?

A. As I understand from past proceedings, the negative variable O&M values modeled in AURORA for hydro resources are arbitrary. For example, in the 2014 GRC, I contested the Company's use of (-)$[redacted]/MWh variable O&M for hydro resources.[56/] In that proceeding, the Company justified the use of the negative variable O&M as follows:

> Avista included a negative variable O&M to each of its hydro facilities (along with all hydro facilities in the WECC) to change the dispatch order of hydro facilities in the market place. Avista has reflected this change in past rate proceedings and IRP's in order to model negative pricing at the Mid-C. Given many renewable resources have production tax credits (PTC), renewable energy certificates (REC), and must-run purchase power agreements (PPA), power markets are incented to go negative when loads are low and must run resources are forced to run so these resources can retain its financial benefits.
>
> The changes made to the AURORA model are to reflect changes in market fundamentals to better match AURORA's prices with forward Mid-Columbia prices. With this change hydro becomes the last resource to be dispatched off when loads are low and renewable output is high.[57/]

Thus, the Company cited two general reasons for why it models negative variable O&M values. First, the Company suggests that this sort of modeling is necessary to model negative prices, driven by production tax credits, renewable energy certificates and power purchase agreements associated with renewable resources. Second, the Company

[55/] Exhibit No. BGM-9 (the Company's Response to ICNU DR 171).

[56/] Docket Nos. UE-140188 and UG-140189 (Consolidated), Exh. No. BGM-1T at 25:9-29:4.

[57/] Id. at 27:7-21.

claims that the change is necessary in order to align the price output of the AURORA model with its expectation of future prices.

Q. IS IT NECESSARY TO MODEL NEGATIVE VARIABLE O&M FOR OWNED HYDRO RESOURCES TO ACCOUNT FOR NEGATIVE PRICING?

A. No. The AURORA modeling used by the Company already includes adjustments to account for the value of production tax credits and renewable energy certificates associated with renewable resources. In AURORA, the Company includes a variable charge of approximately (-)$[redacted]/MWh for wind resources built within the past ten years, representing the opportunity cost of foregone production tax credits. In addition, the Company includes a second negative variable O&M charge in AURORA of approximately (-)$[redacted]/MWh for wind and solar resources, which, as I understand, is designed to represent the value of renewable energy certificates. Thus, it is not necessary to model negative hydro O&M to account for these factors, as they are already being explicitly modeled in AURORA.

Q DOES THE ASSUMPTION RELATED TO NEGATIVE O&M FOR OWNED HYDRO RESOURCE BETTER ALIGN THE AURORA OUTPUT WITH FORWARD PRICES?

A. No. The assumption related to negative hydro O&M has little impact on the ultimate prices calculated in the AURORA model. In the model iteration that I reviewed, the AURORA model calculated an average annual Mid-Columbia price of $[redacted]/MWh including the negative O&M assumption and an average annual Mid-Columbia price of $[redacted]/MWh excluding the negative O&M assumption. Accordingly, the argument that this sort of modeling is necessary to better align the model results with forward curves has little merit, because the assumption does not materially impact market prices.

Q. DID THE COMPANY EXPLAIN ITS BASIS FOR INCREASING THE NEGATIVE O&M CHARGE RELATIVE TO THE 2014 GRC?

A. No. As noted above, the Company has increased the negative hydro O&M charge from $[redacted]/MWh to $[redacted]/MWh since the 2014 GRC. The lack of any reasoned explanation for such a change is another indication of the arbitrary nature of this assumption and further reason why the assumption should not be used for establishing the level of power costs used for ratemaking.

Q. WHAT DO YOU RECOMMEND?

A. I recommend that the variable O&M associated with owned-hydro resource be modeled at zero. The impact of this adjustment is an approximate $0.3 million reduction to power costs, on a Washington-allocated basis.

e. Bidding Adder Assumption

Q. WHAT ARE THE BIDDING ADDER INPUTS IN THE AURORA MODEL?

A. The bidding adder is another assumption in the AURORA model that increases the variable cost of a resource when the model determines whether to dispatch the resource into the market. In contrast to the variable O&M expense detailed above, the bidding adder assumption was primarily put in place in AURORA to influence the commitment decisions made by the model.

Q. WHAT INPUTS DOES THE COMPANY USE FOR THE BIDDING ADDER ASSUMPTIONS?

A. The Company includes a range of bidding adder assumptions for wind, solar, and hydro resources. In contrast to the negative O&M assumptions above, which are only applied to owned-hydro resources, the bidding adder assumption is applied to a wider range of resources, including non-owned resources. The input values typically range from (-)$[redacted]/MWh to (-)$[redacted]/MWh.

Q. DID YOU ASK THE COMPANY TO PROVIDE SUPPORT FOR THESE INPUT VALUES?

A. Yes. In ICNU Data Request 173, the Company was requested to provide support for these values.[58/] The Company responded using the verbatim response detailed above in relation to the negative hydro O&M values that it provided in the 2014 GRC. The Company also stated that it did not have any support for the various modeled values, noting that "[t]here are no separate workpapers associated with the bid adder values."[59/]

Q. DO YOU AGREE WITH THE COMPANY'S USE OF THE BIDDING ADDER ASSUMPTION?

A. No. Apart from the fact that the inputs are based on arbitrary values, as previously noted, this sort of modeling is not necessary to account for the fact that many renewable resources have production tax credits, renewable energy certificates, and must-run purchase power agreements. The Company already includes a variable O&M charge to account for production tax credits and renewable energy certificates. Renewable resources are also modeled in AURORA as must-run resources to account for any offtake agreements they may have. Thus, it is not necessary to have a separate biding adder adjustment to account for the attributes of renewables referenced in response to ICNU Data Request 173.

58/ Exh. No. BGM-9 (the Company's Response to ICNU DR 173).

59/ Id.

Q. DO YOU AGREE THAT THIS SORT OF MODELING IS NECESSARY TO MATCH THE AURORA MODEL RESULTS WITH FORWARD PRICES?

A. No. In my view, this sort of "results driven" approach to power cost modeling is not the best way to approach power cost modeling. In fact, it eliminates the need to use a model to begin with. If the price results which the Company desires are known, then the Company could perform its power cost calculations outside the model in a simple spreadsheet. In addition, these sorts of assumptions are also likely a driver of why the Company's AURORA modeling has overstated power costs in the past. In comparison to the prices identified above in relation to the negative hydro O&M values, eliminating this assumption produced an average annual Mid-Columbia market price of approximately $[redacted]/MWh, only a minor impact on the AURORA modeled pricing.

Q. WHAT DO YOU RECOMMEND?

A. I recommend eliminating the bidding adder assumptions in the model on the basis that they are unsupported and do not improve the accuracy of the model. The impact of this recommendation is an approximate $0.4 million reduction to power costs on a Washington-allocated basis.

VI. MULTI-YEAR RATE PLAN

Q. WHAT DOES THE COMPANY PROPOSE WITH RESPECT TO A MULTI-YEAR RATE PLAN?

A. The Company proposes a multi-year rate plan, with the first rate period corresponding to calendar year 2017, and the second period corresponding to the six months ending June

2018 (the "Stub Period").[60/] For electric services, the Company proposes to use funds accrued to the ERM to offset the increase for the second, six-month rate period.[61/]

Q. DOES A SIX-MONTH RATE PLAN PROVIDE SUFFICIENT VALUE TO RATEPAYERS TO WARRANT A SECOND RATE INCREASE?

A. No. A six-month rate plan is too short to provide sufficient value to ratepayers to warrant the extraordinary ratemaking requested by the Company. In fact, from the perspective of ratepayers, such a rate plan is not preferred because it would potentially allow the Company to increase rates twice in the same year, once on January 1, 2018, and again on July 1, 2018, corresponding to the potential rate effective date of the Company's next general rate case. Far from providing rate certainty, this sort of rate plan structure creates even more uncertainty for ratepayers.

Q. IS IT COMMON FOR OTHER UTILITIES TO GO SIX MONTHS WITHOUT FILING A RATE CASE?

A. Yes. There is no requirement for a utility to file annual rate cases, and it is not uncommon for utilities to wait some period of time before filing a new rate case. In fact, many utilities will wait a number of years between filing a rate case and are able to manage operations such that they continue to earn reasonable returns.

Q. WHY DOES THE COMPANY BELIEVE IT IS JUSTIFIED IN A SECOND RATE INCREASE?

A. It is important to note that under the Traditional method, the Company would not be able to claim any rate increase for the Stub Period. Under the Traditional method, the calculation of revenue requirement would not change as a result of moving the rate period out an additional six months. Rather, it is the Attrition Allowance model through which

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60/ See Exh. No. SLM-1T at 3:7-4:8.

61/ Id.

the Company is claiming it should be entitled to a second-year rate increase. That is, the Company uses the Attrition Allowance model to escalate the costs in question nearly three years beyond the end of the test period.

Q. IS THE CLAIM OF ATTRITION A REASON TO JUSTIFY A SECOND RATE INCREASE?

A. No. To the extent that the Company is justifying the second rate increase on the application of the Attrition Allowance method, it is not a reason for the Company to receive additional rate relief through an attrition allowance. Providing the Company with an additional attrition allowance in exchange for delaying the filing of its next general rate case is contrary to the nature of the attrition allowance. Based on the standard evaluated by the Commission in the 2015 GRC, the approval of an attrition allowance requires demonstration "that the circumstances driving attrition are outside of the Company's control."[62/] If such a showing is to be made by the Company, it must show the current steps that it is taking to slow the growth in plant that is causing the attrition allowance in the Attrition Allowance revenue requirement method. By escalating the costs in question out an additional year, parties will not have the opportunity to review whether the Company is undertaking steps to control its expenditures in the time between now and the second rate period. To the extent that the Company is continuing to experience attrition in the second rate period, it could file a rate case and make an appropriate showing at that time. At this time, however, it does not best serve the public interest to presume that the conditions leading to attrition will exist in the second rate period.

62/ 2015 GRC, Order 05 at ¶ 129.

Q. IF THE COMMISSION IS TO APPROVE A SECOND RATE INCREASE, WHAT DO YOU RECOMMEND?

A. If the Commission is to approve any additional revenue requirement for the additional six-month rate period, I propose that it be implemented as a single rate change corresponding to the rate effective date of this proceeding. To accommodate the additional six-month period, however, the attrition model could be adjusted to increase rates to the mid-point of the 18-month period. That is, rather than increasing the base results by 2.25 years (as implemented in my model), the Attrition Allowance model could be adjusted to increase the attrition base by 2.5 years. If necessary, the rate change could still be offset by ERM funds in the case of electric services.

Q. WHAT IS THE IMPACT OF THIS RECOMMENDATION?

A. Based on this application of additional escalation in my model, this sort of approach would allow for an additional $2.2 million of revenue for electric services and an additional $0.6 million of revenue for natural gas services, relative to my Attrition Allowance model results, detailed above. In other words, increasing the escalation to 2.5 years in my Attrition Allowance model would still result in revenue requirement reductions for the Company, albeit the reductions would be $1.7 million for electric services and $4.2 million for natural gas services.

Q. DOES THIS CONCLUDE YOUR RESPONSE TESTIMONY?

A. Yes.