Exhibit No.__(BGM-1T)
Docket Nos. UE-140188/UG-140189
Witness: Bradley G. Mullins

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. AVISTA CORPORATION d/b/a AVISTA UTILITIES, Respondent.	Docket No. UE-140188 Docket No. UG-140189 *(consolidated)*

RESPONSE TESTIMONY OF BRADLEY G. MULLINS

ON BEHALF OF

THE INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

REDACTED VERSION

July 22, 2014

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EXHIBITS

I. INTRODUCTION

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 consultant representing industrial customers throughout the western United States. I am appearing on behalf of the Industrial Customers of Northwest Utilities ("ICNU"), a non-profit trade association whose members are large customers served by electric utilities throughout the Pacific Northwest, including Avista Corporation ("Avista" or the "Company").

Q. PLEASE SUMMARIZE YOUR EDUCATION AND WORK EXPERIENCE.

A. I received Bachelor of Science degrees in Finance and in Accounting from the University of Utah. I also received a Master of Science degree in Accounting from the University of Utah. After receiving my Master of Science degree, I worked at Deloitte Tax, LLP, where I was a Tax Senior providing tax consulting services to multi-national corporations and investment fund clients. Subsequently, I worked at PacifiCorp Energy as an analyst involved in regulatory matters primarily involving power supply costs. I began performing independent consulting services in September 2013. I currently provide consulting services for utility customers, independent power producers, and qualifying facilities on matters ranging from power costs and revenue requirement to power purchase agreement negotiations. A further description of my educational background and work experience can be found in Exhibit No.___(BGM-2).

Q. WHAT TOPICS WILL YOUR TESTIMONY ADDRESS?

A. This testimony addresses matters related to the Company's revenue requirement—including power costs, its proposed mechanism for returning to customers the proceeds from sales of renewable energy credits ("RECs"), the attrition study, and its proposed decoupling mechanism.

Q. ARE OTHER WITNESSES SUBMITTING TESTIMONY ON BEHALF OF ICNU IN THIS PROCEEDING?

A. Yes. ICNU Exhibit No.___(MPG-1T) contains the Responsive Testimony of Mr. Michael P. Gorman, who will discuss issues related to cost of capital in this proceeding. In addition, ICNU Exhibit No.___(RRS-1T) contains the Responsive Testimony of Mr. Robert R. Stephens, who will discuss issues related to rate spread and rate design, and decoupling in this proceeding.

Q PLEASE PROVIDE AN OVERVIEW OF YOUR TESTIMONY.

A. I make the following recommendations and my testimony is organized respectively:

1. **Revenue Requirement Methodology.** The Company's filing includes revenue requirement calculated using two separate methodologies—an attrition study and a pro forma cross check study—neither of which conform to the methodology approved by this Commission. The Company has not satisfied the burden necessary to justify deviation from the Commission's long-standing revenue requirement methodology, and, accordingly, these methodologies should be rejected.

2. **Attrition Revenue Requirement.** The Commission should reject the Company's request for extraordinary rate relief through an attrition adjustment in this proceeding. The Commission should also reject the Company's proposal to rely on trends to calculate revenue requirement. Removing the impact of trending in the Company's attrition study results in a $42.9 million reduction to the Company's Washington-allocated revenue requirement.

3. **Pro Forma Cross Check Study.** The Commission should reject the Company's pro-forma cross check study on the basis that it includes adjustments not permitted in rates in Washington, as follows:

a. **Forecast Capital Expenditures**. The Commission has a longstanding practice of not allowing forecast capital expenditures to be included in rate base. Removing these from the pro forma cross check study reduces Washington-allocated revenue requirement by $28.1 million.

b. **Lost Energy Efficiency Revenues**. The Commission has also not allowed adjustments to impute lost revenues related to energy efficiency. Removing these lost revenues from the pro forma cross check study reduces Washington-allocated revenue requirement by $5.4 million.

4. **Power Supply Cost Issues.** Four separate adjustments should be made to the Company's power supply costs, which collectively will result in a $7.9 million reduction to Washington revenue requirement. The adjustments have been accounted for in revenue requirement collectively and include the impact of an off-setting balancing adjustment, as follows:

a. **Colstrip Outage Rate.** The Commission should require the Company to remove from the outage rate calculated for Colstrip a long, six-month outage that occurred in 2009 and which is of the type that has historically been removed for ratemaking purposes. This adjustment reduces Washington-allocated power costs by approximately $1.3 million.

b. **Negative Variable O&M.** The Commission should require the Company to remove the negative variable Operation and Maintenance ("O&M") values modeled for hydro resources in AURORA. This modeling is the result of an arbitrary assumption, which is unrelated to the actual variable cost of hydro resources in operation. This adjustment reduces Washington-allocated power costs by approximately $5.3 million.

c. **Dispatch Margin.** The Commission should require the Company to remove an optional dispatch margin model parameter in AURORA. The Company has no justification to support the use of this parameter in this proceeding. This adjustment reduces Washington-allocated power costs by approximately $1.4 million.

d. **Phantom Congestion.** The Company reduces the modeled capacity available to transfer energy from the Northwest to California below actual limits as a result of what it calls "phantom congestions." This convention has been applied for the sole purpose of increasing the market price calculated in the model and, therefore, should be removed. Removing this assumption reduces Washington-allocated power costs by approximately $1.5 million.

5. **REC Rebate Mechanism.** The Company's proposal for a mechanism to pass through REC sales proceeds onto customers included a provision that would allow it to pass through the cost of future REC purchases, as well. Because there is no Commission requirement to pass the cost associated with property purchases onto

customers, I propose that the mechanism be modified to only reflect REC sales proceeds.

6. **Decoupling Mechanism.** Due to their unique characteristics, industrial rate classes should be exempt from any decoupling mechanism approved by this Commission. Applying decoupling to industrial rate classes will cause intra-class inequity and will discourage industrial customers from participating in energy efficiency programs.

Q. HAVE YOU PREPARED A TABLE TO SUMMARIZE ICNU'S OVERALL RECOMMENDATION?

A. Yes. The following table provides a summary of ICNU's recommended reduction to revenue requirement in this proceeding. In addition to adjustments that will be discussed in my testimony, this table includes an adjustment to reflect the revenue requirement impact of the cost of capital recommendation made by Mr. Gorman. A detailed revenue requirement calculation for each of these adjustments is contained in Exhibit No.___(BGM-3) through Exhibit No.___(BGM-9). ICNU may also adopt additional adjustments proposed by other parties in this proceeding.

TABLE 1
ICNU INTEGRATED REVENUE REQUIREMENT SUMMARY

		Washington Revenue Requirement ($000)	
		Attrition Study	**Pro-forma Cross Check**
Company Filing:			
Increase / (Decrease) from 2014		**18,201**	**18,201**
Adjustments:			
ICNU-1	Cost of Capital (Sponsored by Mr. Gorman)	(12,572)	(11,878)
ICNU-2	Remove Trending from Attrition Study	(42,874)	-
ICNU-3	Remove Forecast Capital Expenditures	-	(28,051)
ICNU-4	Remove Lost Energy Efficiency Margins	-	(5,353)
ICNU-5	Net Power Cost Adjustments	(7,855)	(7,855)
Total Adjustments		**(50,729)**	**(41,259)**
Total Adjusted Revenue Requirement:			
Increase / (Decrease) from 2014		**(45,100)**	**(34,937)**
Percentage Change from 2014 Rates		*-9.38%*	*-7.26%*

Q. PLEASE EXPLAIN THE PRO FORMA CROSS CHECK COLUMN IN TABLE 1.

A. This is the Company's alternative method for arriving at its proposed revenue requirement.

II. REVENUE REQUIREMENT METHODOLOGY

Q. DID THE COMPANY RELY ON THE COMMISSION APPROVED REVENUE REQUIREMENT METHODOLOGY TO ARRIVE AT ITS PROPOSED RATE INCREASE?

A. No. The Company calculated revenue requirement using two alternative methods, an attrition study and a pro forma cross-check study. The attrition study was calculated based on the Company's weather normalized results of operations for the test period (the

12 months ending June 2013), escalated based on historical trends in major cost categories. The pro forma cross check study was similar to the Commission's traditional ratemaking approach—a historical test period with pro forma and restating adjustments—except that the Company includes several adjustments not permitted in Washington, such as forecast capital expenditures and an adjustment related to lost energy efficiency revenues.

Q. ARE EITHER OF THESE REVENUE REQUIREMENT METHODOLOGIES CONSISTENT WITH COMMISSION APPROVED METHODOLOGY?

A. No. Neither of these methodologies conform to the Commission's established methodology.[1/] The Commission, in adopting the two year rate plan in the 2012 General Rate Case ("GRC"), was clear that it was not approving the Company's attrition study revenue requirement methodology. The Commission stated that, "[i]n conditionally approving the Settlement, we are not endorsing the specific attrition methodologies, assumptions, or inputs used in this case."[2/] In fact, the Commission set temporary rates for 2014 acknowledging that it had concerns with the Company's attrition study, stating: "we make clear that the testimony and trending data offered in support of the proposed rate increase for 2014 are substantially less precise than we would require in a fully-litigated rate case."[3/]

1/ For a complete description of the Commission's established methodology, see Washington Utilities and Transportation Commission v. Puget Sound Energy, Docket Nos. UE-090704/UG-090705, Order 11 (April 2, 2010).

2/ Washington Utilities and Transportation Commission v. Avista Corp., Docket Nos. UE-120436/UG-120437, Order 09 at ¶ 77 (Dec. 2, 2012) ("2012 GRC Order 09").

3/ Id. at ¶ 72.

Q. WAS ANY CALCULATION OF REVENUE REQUIREMENT BASED ON THE COMMISSION APPROVED METHODOLOGY INCLUDED IN THE FILING?

A. No. The Company should have a relatively high burden necessary to demonstrate that it is in the public interest to calculate revenue requirement using a new methodology, as proposed in this case. To satisfy that burden, it is essential that the Company also include in its filing revenue requirement calculations based on the methodology previously approved by the Commission. This must be done in order to justify any differences between the revenue requirements calculated using the new method and the old method. The essence of this requirement was codified by the Commission in WAC § 480-07-510(3)(e)(i), where it established the following rule:

> *Change in methodologies for adjustments*. If a party proposes to calculate [a revenue requirement] adjustment in a manner different from the method that the commission most recently accepted or authorized for the company, it must also present a work paper demonstrating how the adjustment would be calculated under the methodology previously accepted by the commission, and a brief narrative describing the change. Commission approval of a settlement does not constitute commission acceptance of any underlying methodology unless so specified in the order approving the settlement.

In this case, the Company has proposed to use two different unapproved revenue requirement calculations, yet has not included any calculation performed using the Commission approved methodology in order to justify why the results of these different methods are reasonable.

Q DID ICNU REQUEST FOR THE COMPANY TO CALCULATE REVENUE REQUIREMENT USING THE COMMISSION APPROVED METHODOLOGY?

A. Yes. One of the initial data requests that ICNU submitted was for the Company to demonstrate what revenue requirement would have been absent, the attrition study adjustment:

ICNU DATA REQUEST 1.2:

> Please state what base rate increase (or decrease) from 2014 levels would have occurred if an attrition adjustment were excluded from the filing and provide workpapers to derive this value on the same basis as they were provided in the original filing.

COMPANY RESPONSE:

> Were the Attrition adjustments excluded, the pro forma studies that were provided as a cross check to the attrition analyses would independently support the requested electric and natural gas increases. See Andrews Exhibit Nos. _(EMA-4) and _(EMA-5), and Andrews workpapers previously provided.[4/]

Unfortunately, the pro forma cross check studies, which the Company claims also includes some form of attrition adjustment, are not based on the Commission's most recently approved methodology. Because a study using the Commission approved methodology was not provided, I do not believe the Company has provided the evidence necessary to demonstrate that its alternate revenue requirement calculations are in the public interest.

Q. WHAT OTHER EVIDENCE HAS THE COMPANY PROVIDED TO DEMONSTRATE THAT ITS ALTERNATIVE REVENUE REQUIREMENT METHODOLOGIES ARE IN THE PUBLIC INTEREST?

A. Despite the Commission's concerns with the merits of the Company's proposed attrition study revenue requirement methodology in the 2012 GRC,[5/] the Company has proposed to use the same attrition trending methodology in this proceeding, without providing any additional justification of its merits. The only support presented for the methodology was included in the Direct Testimony of Elizabeth M. Andrews, who, rather than presenting new information for the Commission to evaluate, simply references the Direct Testimony

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4/ Exh. No.___(BGM-10).

5/ 2012 GRC Order 09 at ¶ 72.

of Dr. Mark Lowry filed in the 2012 GRC.[6/] Dr. Lowry, however, is not a witness to this proceeding as of July 22, 2014, nor is his testimony in the 2012 GRC subject to cross examination in this proceeding. This further demonstrates that the Company has not provided the evidence necessary for the Commission to evaluate the alternative revenue requirement methodologies in this proceeding.

Q. DO YOU HAVE OTHER CONCERNS REGARDING THE COMPANY'S REVENUE REQUIREMENT METHODOLOGIES?

A. Yes. The Company was able calculate the same level of revenue requirement using both methods. This was done through the use of accounting plugs and, apparently, by targeting the level of forecast capital expenditures in the pro forma cross-check study necessary to achieve the same rate increase calculated in the attrition study. While the total revenue requirement calculation was the same, the components of that revenue requirement—for instance, operations and maintenance expense, taxes, rate base, etc.—are entirely different.

Q. WHY DOES THIS CREATE A CONCERN?

A. It creates numerous inconsistencies within the Company's filing. For example, the Company appears to rely on the attrition study to calculate revenue requirement, yet relies on the pro forma cross check study to perform cost of service calculations. Because the individual cost components are not the same between the two studies, the cost of service results are allocated in a manner that is inconsistent with the overall revenue requirement. This sort of inconsistency can also be noted in Table 1, above, where the impact of a change to the Company's cost of capital is different in the attrition study than in the pro forma cross check study.

6/ Exh. No___(EMA-1T) at 11-12.

Q. WHAT IS YOUR PROPOSAL REGARDING THE COMPANY'S REVENUE REQUIREMENT METHODOLOGY?

A. I recommend that the Commission reject the Company's filing altogether on the basis that the Company did not provide the evidence necessary to demonstrate that the two unapproved revenue requirement methodologies are in the public interest, nor present any information to demonstrate the level of rate change warranted using the Commission approved methodology. Notwithstanding, I will discuss, in the sections that follow, the problems with these two methods and how to adjust them to conform to how the Commission traditionally calculates revenue requirement.

III. ATTRITION STUDY

Q. PLEASE PROVIDE A SUMMARY OF WHY YOU BELIEVE THE COMMISSION SHOULD NOT MAKE A FINDING OF ATTRITION IN THIS PROCEEDING.

A. The Company has requested that Commission make a finding of ongoing attrition in this proceeding.[7/] In doing so, the Company also tacitly requests that the Commission approve its attrition study as permanent ratemaking methodology in Washington. The Commission has historically reserved the use of an attrition adjustment for extraordinary circumstances, and, while the Company has not demonstrated that extraordinary circumstances will exist in the rate year, an extraordinary circumstance cannot by definition be an ongoing phenomenon. Accordingly, I recommend that the Commission make a finding that attrition is neither present in the rate year nor on an ongoing basis. In addition, the trending methodology proposed by the Company is fundamentally flawed

7/ Exh. No.___(KON-1T) at 11.

and should not be relied on by the Commission to establish rates in Washington on a permanent basis.

Q. HOW DO YOU PROPOSE TO ADJUST THE ATTRITION STUDY TO MAKE IT CONFORM TO THE COMMISSION'S APPROVED METHODOLOGY?

A. If the Commission decides to rely on the attrition study in this proceeding, I propose to eliminate the impact of attrition by removing all trend components of that study. The impact of removing all trends from the attrition study is reduction to revenue requirement of $42.9 million on a Washington-allocated basis, which has been summarized in workpapers as adjustment ICNU-2.

Q. PLEASE EXPLAIN YOUR UNDERSTANDING OF THE USE OF ATTRITION ADJUSTMENTS IN WASHINGTON.

A. While there have been many instances where utilities have argued against using the Commission's long-standing ratemaking methodology—a historical test period with average of monthly average rate base valuations—an attrition adjustment was apparently not approved in Washington until 1981 when the Commission, in Cause No. U-81-16, approved an attrition adjustment for Washington Water Power Company ("WWP"), the Company's predecessor.[8/] While it allowed the Company to adjust its revenue requirement to reflect forecast rate year revenues, expenses and rate base, the Commission was clear to identify that extraordinary circumstances existed in that proceeding to justify the extraordinary rate relief being requested through an attrition adjustment. Namely, the Commission found that the Company, likely as a result of the

8/ Washington Utilities & Transportation Commission v. The Washington Water Power Co., Cause No. U-81-16, Second Supplemental Order (Nov. 25, 1981), if there are previous instances of an attrition adjustment, my research did not reveal that.

high interest rate environment that existed in the early 1980s, would not be capable of raising the necessary funds to continue a particular construction program.[9/]

Q. HAS THE COMMISSION PREVIOUSLY DETERMINED WHETHER ATTRITION SHOULD BE USED TO GRANT GENERAL RATE RELIEF, AS THE COMPANY HAS REQUESTED IN THIS PROCEEDING?

A. Yes. In 1992, the Commission declined to approve an attrition adjustment for Washington Natural Gas as an ordinary ratemaking methodology. The Commission articulated that an attrition adjustment should be limited to extraordinary circumstances, as follows:

> The Commission concludes that no attrition adjustment should be granted in this case. An adjustment for attrition is an extraordinary measure, not generally included in general rate relief. A request for such an adjustment should be based on extraordinary circumstances, not shown by the company to be present in this case.[10/]

Q. HAS THE COMPANY DEMONSTRATED THAT EXTRAORDINARY CIRCUMSTANCES EXIST TO JUSTIFY AN ATTRITION ADJUSTMENT IN THIS PROCEEDING?

A. No. The Company justified the use of an attrition adjustment based on claims that the traditional ratemaking approach in Washington will not provide the opportunity to recover the costs associated with new capital additions.[11/] The Company, however, cannot point to any discrete—i.e., extraordinary—investment that it must make in the coming years. Rather, the Company provided an itemized list over 106 different capital

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9/ Id. at 41-42.

10/ Washington Utilities & Transportation Commission v. Washington Natural Gas, Docket No. UG-920840, Fourth Supplemental Order at 20 (Sep. 27, 1993).

11/ Exh. No. ___(SLM-1T) at 5.

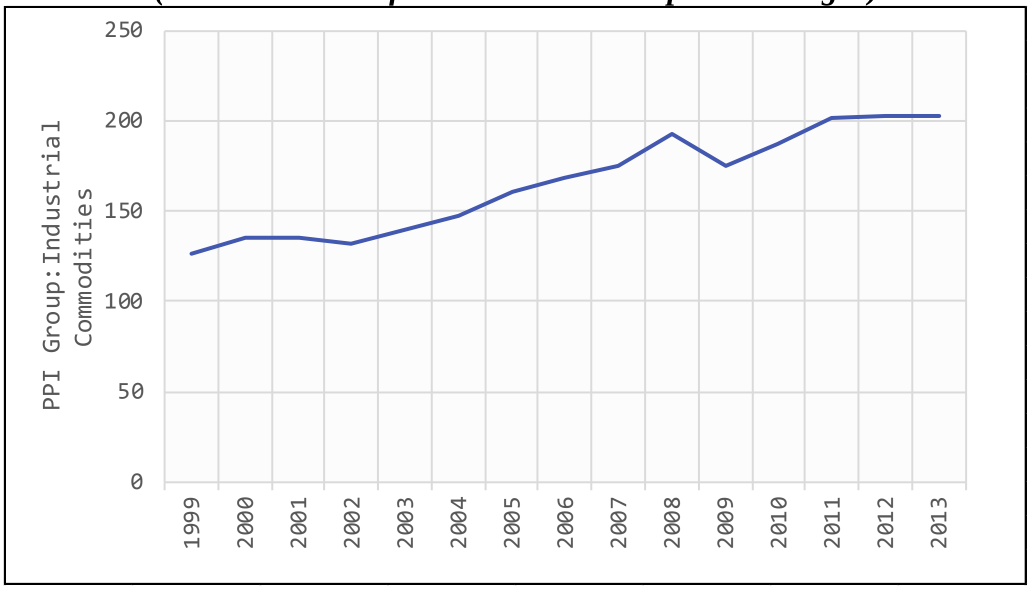
projects, many of which are blanket accounts coving capital spending on undetermined, small projects.[12/]

Q. DO YOU AGREE WITH THE COMPANY THAT THE INCREASING COST OF FACILITIES IS A REASON TO APPROVE AN ATTRITION ADJUSTMENT?

A. No. The Company claims that the cost of replacing existing facilities is much more today than the cost paid for those facilities forty to sixty years ago. The Company, however, has existed for over one hundred years, and has been replacing equipment of that age for some time now. The Company has provided no evidence to suggest that the cost differential of replacing a fifty year old piece of equipment with a new piece of equipment is any different today than it would have been, say, fifteen years ago. On the contrary, producer prices have actually remained more stable in recent years than they have at any time in the past fifteen years, as shown in Figure 1, below. This suggests that the circumstances surrounding the Company's capital equipment needs are actually less extraordinary than fifteen years ago, when prices were increasing at a greater rate.

12/ Exh. No. ___(DBD-4).

FIGURE 1
PRODUCER PRICE INDEX
COMMODITY GROUP: INDUSTRIAL COMMODITIES
(Source Bureau of Labor Statistics: http://data.bls.gov)



Q. ARE THE COMPANY'S CLAIMS OF HISTORICAL UNDER-EARNING A VALID REASON TO APPROVE AN ACCOUNTING ADJUSTMENT FOR ATTRITION?

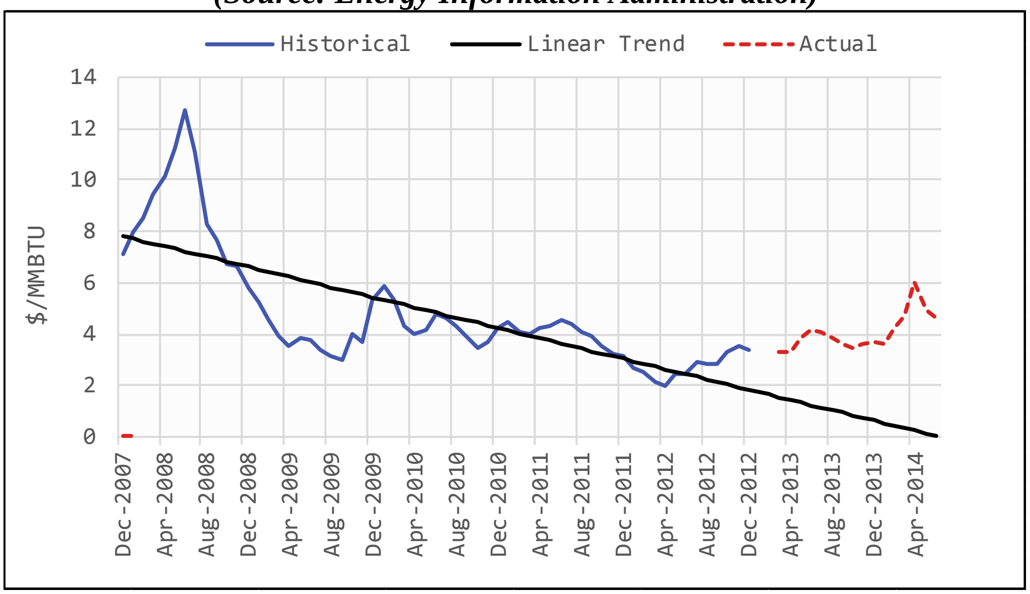
A. No. As was demonstrated in its pursuit of the Voluntary Severance Incentive Plan ("VSIP") subsequent to the settlement in the 2012 GRC, the Company has a greater degree of control over its costs and capital expenditures than has been suggested in testimony. The Company, through its VSIP, was able to remove $5.1 million in costs and achieve a return on equity that exceeded what it was authorized in 2013. It follows that the Company could have taken similar measures in prior years in order to improve its returns.

Q. REGARDLESS OF WHETHER THE COMMISSION MAKES AN ATTRITION DETERMINATION IN THIS PROCEEDING, IS A THE COMPANY'S TREND ANALYSIS AN ACCURATE METHOD TO SET RATES?

A. No. Trends change over time and cannot be relied on as an accurate method to predict future results. As anyone who has invested in the stock market knows, a trend has the tendency to continue for a period, and then change, or "break," with little to no warning. Reliance on a trend ignores the underlying drivers that are causing the change to begin with, often producing results that are unreasonable.

Consider, for example, if the Company were to forecast natural gas prices using the same trending period that was used in its attrition study. The result, detailed in Figure 2 below, would forecast average Henry Hub gas prices to be less than zero by 2014—an impossible result.

FIGURE 2
HENRY HUB NATURAL GAS PRICES
TRENDING FORECAST BASED ON PRICING 2007 – 2012
(Source: Energy Information Administration)



Q. IF A TRENDING ANALYSIS IS USED, WILL THE BENEFITS OF THE COMPANY'S FUTURE COST REDUCTION INITIATIVES BE RETURNED TO CUSTOMERS?

A. No. When it approved the two year rate plan in the 2012 GRC, the Commission acknowledge the Company's VSIP, stating, "if Avista were to 'overearn' through savings efforts, those savings would become the new norm in the next rate case which would serve to benefit ratepayers in the future."[13/] Unfortunately, if a trending analysis is approved on an ongoing basis the rates paid by customers will never fully reflect those savings initiatives, as the Company's revenue requirement will continually be escalated above the level in the test period when the savings were achieved.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATION RELATED TO ATTRITION.

A. The facts presented in this case do not support a finding of attrition at this time. Accordingly, a reduction of $42.9 million should be made to the attrition study revenue requirement in this proceeding to conform the study to traditional ratemaking standards. This adjustment has been detailed as ICNU-2 in Table 1.

IV. PRO FORMA CROSS CHECK STUDY

Q. PLEASE PROVIDE AN OVERVIEW OF THE PRO FORMA CROSS CHECK STUDY.

A. The pro forma cross check study is similar to the Commission's traditional rate making approach, with the exception of two types of revenue requirement adjustments that, to my knowledge, have never been approved by this Commission for inclusion in rates. The first type of adjustment is a forecast of future capital expenditures. The second adjustment represents lost revenues resulting from future energy efficiency programs. The Company views these two types of adjustment as similar, in purpose, to its attrition study, and has designed them to cause the revenue requirement calculated in the pro forma cross check study to tie exactly to the attrition study.

13/ 2012 GRC Order 09 at ¶ 75.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE PRO FORMA CROSS CHECK STUDY?

A. I recommend that these two types of adjustments—forecast capital expenditures[14/] and lost energy efficiency margins[15/]—be removed from the pro forma cross check study. Removing forecast capital expenditures reduces revenue requirement calculated using the pro-forma cross check study by $28.1 million. Removing the lost energy efficiency revenues reduces revenue requirement calculated using the pro forma cross check study by $5.4 million.

Forecast Capital Expenditures

Q. WHY SHOULD FORECAST CAPTIAL EXPENDITURES BE EXCLUDED FROM THE PRO FORMA CROSS CHECK STUDY?

A. The Commission has established precedent of not allowing utilities to include forecast capital expenditures in their rate filings. The position of the Commission on this matter was recently articulated in Docket No. UE-130043, where PacifiCorp requested Commission approval to include forecast capital additions related to environmental upgrades at the Jim Bridger power station and a fish collector at the Merwin hydro facility. In that proceeding, the Commission held that while the environmental upgrades at the Jim Bridger power station did reach a "known and measurable" status, the Merwin fish collector did not.[16/] The Commission articulated the standard by which it analyzed these projects for inclusion in rate base, referring to an earlier order in a proceeding with Puget Sound Energy:

14/ Identified as adjustment numbers 4.00, 4.01, and 4.02 in the pro forma cross check study workpapers of Elizabeth M. Andrews.

15/ Identified as adjustment number 4.03 in the pro forma cross check study workpapers of Elizabeth M. Andrews.

16/ Washington Utilities and Transportation Commission v. PacifiCorp., Docket No. UE-130043, Order 05 at ¶ 203-209 (Dec. 4, 2013).

> The known and measurable test requires that an event that causes a change in revenue, expense or rate base must be known to have occurred during, or reasonably soon after, the historical 12 months of actual results of operations, and the effect of that event will be in place during the 12-month period when rates will likely be in effect. Furthermore, the actual amount of the change must be measurable. This means the amount typically cannot be an estimate, a projection, the product of a budget forecast, or some similar exercise of judgment – even informed judgment – concerning future revenue, expense or rate base. There are exceptions, such as using the forward costs of gas in power cost projections, but these are few and demand a high degree of analytical rigor.[17/]

Q. DO THE CAPITAL EXPENDITURES PROPOSED IN THE COMPANY'S PRO FORMA CROSS CHECK STUDY MEET THIS STANDARD?

A. No. The Company has relied on its capital budget to develop its forecast of capital expenditures in this proceeding,[18/] and the Commission has explicitly stated that a budget should not be reflected in rate base. In addition—unlike the PacifiCorp proceeding, where the capital additions under review were two discrete projects—the Company has proposed that the Commission evaluate 109 different capital projects in this proceeding for inclusion in rate base, many of which consist of blanket accounts to cover future unidentified capital needs.[19/] The Commission has adopted a policy to consider post-test-year capital additions on a case-by-case basis, stating that it has "recognized the limits imposed by the 'used and useful' and 'known and measurable' standards while exercising the considerable discretion those standards allow in the *context of individual cases.*"[20/] The Company's filing, however, does not request a review of discrete capital additions.

17/ Washington Utilities and Transportation Commission v. Puget Sound Energy, Dockets UE-090704 *et al.*, Order 11 ¶ 26 (Apr. 2, 2010).

18/ Exh. No. ___(DBD-1T) at 7:5-8-21.

19/ Exh. No. ___(DBD-4).

20/ Washington Utilities and Transportation Commission v. PacifiCorp., Docket No. UE-130043, Order 05 at ¶ 189 (Dec. 4, 2013) (emphasis added).

Rather, it consists of an amalgamation of budgeted projects, for which no rigorous analytical review can be performed. Therefore, it is not possible for the Commission to apply a case-by-case review to determine whether these capital additions warrant deviation from the "used and useful" and "known and measurable" standards, and the Company's proposal to include those capital additions should be rejected.

Q. NOTWITHSTANDING, ARE THE COMPANY'S CAPITAL FORECASTS REASONABLE?

A. No. The amount of capital expenditures that the Company has proposed to include in the pro forma cross check study are detailed in Table 2, below.

TABLE 2
COMPANY PROPOSED CAPITAL EXPENDITURES
IN PRO FORMA CROSS CHECK STUDY
($000)

2013 (Jul-Dec)	2014	2015
$ 162,321	$ 340,115	$ 374,110

Given the size of the Company, I view this level of capital expenditure to be excessive, especially since these numbers do not include any large capital additions. Given the economy in eastern Washington, the Company must prioritize its projects and not simply embark an undefined program to increase its capital expenditures and its rate base.

<u>Lost Energy Efficiency Margins</u>

Q. WHAT ADJUSTMENT IS THE COMPANY MAKING REGARDING LOST ENERGY EFFICIENCY MARGINS?

A. The Company has included an adjustment in its pro forma cross check study to reflect the margins that it would have earned had it not been required to acquire cost effective conservation. The Company argues that "Avista is experiencing attrition due to [its] success in assisting [its] customers with electric energy efficiency through [its] Demand Side Management Program."[21/] Accordingly, it has proposed an adjustment to impute lost revenues at rate of $45.67/MWh on 111,937 MWh of load,[22/] which the Company will not ultimately be required to serve as a result of its conservation programs. This resulted in an increase of $5.1 million to expense and an overall increase of $5.4 million to revenue requirement.

Q. WHAT IS THE FLAW WITH THE COMPANY'S LOGIC?

A. To the extent that energy efficiency is cost effective, the Company will incur no additional costs as a result of pursuing the conservation measures. In fact, the Company should actually benefit as a result of these conservation programs. The Company's proposal is misplaced because it suggests that customers must supply additional revenues in order to cover additional costs which the Company will not incur. Accordingly, I do not believe it is appropriate to include this item as an adjustment at this time.

Q. HAS THE COMMISSION ALLOWED ADJUSTMENTS, SUCH AS THIS, IN RATES IN THE PAST?

A. I understand that a number of similar one-sided mechanisms have been proposed in the past and rejected by the Commission, such as Puget Sound Energy's Conservation Savings Adjustment, and a previous, similar proposal. On top of this, the Company is already requesting a decoupling mechanism. While there are serious concerns about applying a decoupling mechanism to industrial customers, which I discuss later, if it is

21/ Exh. No.___(PDE-1T) at 38:19-21.
22/ Exh. No.___(PDE-1T) at 44:13.

adopted, the need for any additional fixed cost recovery for energy efficiency programs will be mitigated.

Q. DOES THIS PROPOSAL COMPORT WITH WASHINGTON STATE POLICY?

A. No. It creates an appearance of increasing rates because of conservation, and as such could create opposition to utility-funded conservation. Customers want conservation, but the Company should not be guaranteed a future stream of money premised on the idea that the Company didn't plan on conservation measures in the past. Washington policy is to promote conservation.

V. POWER SUPPLY COST ISSUES

Q. HAVE YOU REVIEWED THE COMPANY'S PROPOSED POWER SUPPLY COSTS IN THIS PROCEEDING?

A. Yes. I have reviewed the Company's testimony, exhibits, and workpapers relating to the proposed level of power supply cost, as well as a significant volume of data responses to data requests submitted by ICNU, Commission Staff, and other parties. I have also performed a detailed review of the Company's AURORA modeling, which has been used by the Company to forecast the level of power supply costs presented in the Direct Testimony of William G. Johnson.

Q. WHAT ARE THE RESULTS OF YOUR REVIEW?

A. I have discovered that the Company has included in its power supply cost calculations a long-term, six month outage at Colstrip Unit 4, which the Commission has historically adjusted in rates. I have also discovered several AURORA modeling parameters, for which the Company has no documentation. These modeling parameters are based on arbitrary values, set by the Company in order to increase modeled Mid-Columbia prices, and should be removed from the model. The following table details the power supply cost adjustments that I am proposing in this proceeding, including a balancing adjustment to capture the offsetting nature of all adjustments. Collectively, these adjustments are reflected in the revenue requirement calculation under adjustment ICNU-5 in Table 1.

TABLE 3[23/]
NET POWER COST ADJUSTMENTS
($000)

		Total Company		Washington Allocated
Company Filed Net Power Costs		**178,835**		**116,261**
Adjustments:				
1. Colstrip Outage Rate	(1,983)		(1,289)	
2. Negative Hydro O&M	(8,104)		(5,268)	
3. Dispatch Margin	(2,089)		(1,358)	
4. Phantom Congestion	(2,302)		(1,497)	
5. Balancing Adjustment	*2,939*		*1,911*	
Total Adjustments		**(11,539)**		**(7,502)**
Proposed Net Power Costs		**167,296**		**108,759**

<u>Colstrip Outage Rate</u>

Q. PLEASE EXPLAIN HOW THE COMPANY HAS CALCULATED THE OUTAGE RATE FOR COLSTRIP.

A. In AURORA, the Company has modeled a [redacted] percent outage rate for Colstrip, based on the facility's average outage rate between 2008 and 2012. The facility's outage rates for this period is detailed in Confidential Figure 3, as follows.

23/ Note that the values in Table 3 are slightly different than ICNU-5, the overall net power cost adjustment, presented in Table 1. This difference is a result of applying the power cost adjustments in the revenue requirement model, which includes the impact of other revenue sensitive costs.

CONFIDENTIAL FIGURE 3
COLSTIRP OUTAGE RATES MODELED IN AURORA
Company Filing

[redacted]

As can be noted from the figure, the Colstrip outage rate was approximately three times greater in 2009 than in any other year of the measurement period. The reason for this spike was a major outage that occurred on Colstrip Unit 4 and lasted over six months in 2009. As a result of including this long outage, however, the average outage rate modeled for Colstrip in the AURORA model is skewed in this proceeding, and may not be representative of plant performance in the rate period.

Q. HAS THE COMMISSION OFFERED GUIDANCE ON WHETHER THIS LONG OUTAGE IN 2009 SHOULD BE CAPTURED IN PRO FORMA POWER COST CALCULATIONS?

A. Yes. In Docket No. UE-100749 parties, including ICNU, contested PacifiCorp's inclusion of this extraordinary 2009 Colstrip outage in normalized net power cost calculations.[24/] In that proceeding, the Commission determined that, by including the 2009 outage in pro forma power cost, PacifiCorp's modeling of Colstrip did not

[24/] Washington Utilities and Transportation Commission v. PacifiCorp, Docket No. UE-100749, Order 6 at ¶¶ 138-139 (Mar. 25, 2011).

"represent expected outage levels during the rate year."[25] Accordingly, the Commission capped the outage rate modeled for Colstrip Unit 4 at 8 percent in that proceeding.[26]

Q. HOW DO YOU PROPOSE TO CALCULATE THE OUTAGE RATE FOR COLSTRIP UNIT 4 IN THIS PROCEEDING?

A. I propose to exclude 2009 from the outage rate calculation altogether, as detailed in the following figure.

CONFIDENTIAL FIGURE 4
COLSTIRP OUTAGE RATES MODELED IN AURORA
ICNU Proposed

[redacted]

Q. WHY DO YOU PROPOSE TO EXCLUDE 2009, RAHTER THAN USING AN 8 PERCENT CAP?

A. Notwithstanding that an 8 percent cap is a somewhat arbitrary threshold, in years other than 2009 the Colstrip facility operated at a high level of availability, exceeding 95 percent. If an 8 percent outage rate was assumed in this proceeding, it would be the mathematical equivalent of assuming the 2009 outage rate was 21.2 percent.[27] In my view, a 21.2 percent outage rate is still too anomalous to be representative of the rate period. In addition, to the extent an outage of this nature occurs in the rates period, the

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[25] Id. at ¶¶ 141-142.

[26] Id. at ¶ 142.

[27] This can be demonstrated mathematically as follows: [redacted]

Company will have the opportunity to recover the costs associated with such an outage through its Energy Recovery Mechanism ("ERM"), presuming it can demonstrate that PPL Montana operated the plant prudently.

Q. WHAT IS THE EFFECT OF USING THE OUTAGE RATE PROPOSED IN FIGURE 4 ABOVE?

A. Modeling the outage rate detailed in Figure 4 above results in a $2.0 million total Company, $1.3 million Washington-allocated reduction to net power costs calculated in AURORA in this proceeding.

<u>Negative Hydro Operations and Maintenance Expense</u>

Q. WHAT ASSUMPTIONS HAS THE COMPANY MADE WITH REGARD TO HYDRO VARIABLE OPERATIONS AND MAINTENANCE (O&M) EXPENSE IN AURORA?

A. The Company models variable O&M as a negative value for all hydro resources in the AURORA model. While different values are used for certain facilities, most hydro resources are modeled assuming a variable O&M value of (-)$50.0/MWH. The variable O&M assumed in AURORA for Company owned resources is detailed in Table 3, below.

CONFIDENTIAL TABLE 4
HYDRO O&M COST MODELED IN AURORA

[redacted]

Q. HOW DOES THE USE OF NEGATIVE VARIABLE O&M VALUES IMPACT POWER COSTS?

A. While variable O&M expenses themselves are not reflected in power costs, the AURORA model uses them to determine how to shape hydro output to specific hours within a month. By modeling negative O&M values, the assumption is that each hydro resource will earn an additional $[redacted] in revenue for each megawatt-hour that it produces. Stated otherwise, if the model price in a given hour was $[redacted]/MWH, the hydro plant will operate within the AURORA model as if the price was $[redacted]/MWH. The practical result of this is that the hydro dispatch algorithm will model more hydro energy in low load hours and less hydro energy in high load hours, increasing the overall power costs calculated by the AURORA model.

Q. HAVE YOU ASKED THE COMPANY WHY IT HAS MODELED THE VARIABLE O&M OF HYDRO RESOURCES IN THIS WAY?

A. Yes. In response to ICNU Data Request 5.19, the Company stated its reasoning for modeling negative hydro values 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.[28/]

As I understand the Company's response, the variable O&M values modeled in AURORA are arbitrary, and have no bearing on the actual variable O&M costs associated with hydro resources in actual operations. The Company has suggested that the purpose of these values is to force the model to calculate the results, in terms of Mid-Columbia prices, that it wants. In my view, this sort of approach to power cost modeling is not appropriate. It eliminates the need to use model to begin with, as the Company can simply tweak the model to get the results it desires.

28/ Exh. No.___(BGM-10) (the Company's response to ICNU Data Request 5.19).

Q. WHAT DOES HYDRO VARIABLE O&M HAVE TO DO WITH NEGATIVE PRICING, PRODUCTION TAX CREDITS, RENEWABLE ENERGY CERTIFICATES AND MUST RUN POWER PURCHASE AGREEMENTS?

A. It appears that the Company is attempting to model oversupply events, which often lead to negative pricing in the Northwest. The variable O&M cost of a hydro resource, however, has little to no impact on these events in actual operation. If the Company's intent was to model oversupply, then that should have been represented in the supply-side resources and loads modeled in AURORA. It should not be based on an arbitrary parameter, which is adjusted in order force the model to a predetermined result.

Q. DID THE COMPANY PROVIDE ANY SUPPORT FOR THE SPECIFIC VALUES THAT IT ASSUMED FOR THE NEGATIVE VARIABLE O&M VALUES IN AURORA?

A. No. In a response to a data request to provide all documentation, analysis, and workpapers used to support the negative variable O&M values modeled in AURORA, the Company responded that, "Avista has not retained any documentation, analysis, or workpapers beyond what is filed in the case regarding entering negative variable O&M values in AURORA."[29/] It follows that the Company has no basis to suggest that the particular values detailed in Table 4, above, produce any more accurate results, than, for example, $5/MWH, (-)$1,000/MWH, or even (-)$100,000/MWH. Accordingly, I do not think that the Company is justified in using these negative values in its power cost forecast.

Q. WHAT IS YOUR RECOMMENDATION IN REGARD TO HYDRO NEGATIVE VARIABLE O&M?

A. I recommend that all negative hydro variable O&M values be set to zero in the AURORA model on the basis that they are arbitrary and undocumented.

29/ Id. (the Company's response to ICNU Data Request 5.20.)

Q. WHAT IS THE IMPACT OF REMOVING THE NEGATIVE HYDRO VARIABLE O&M INPUTS FROM AURORA?

A. Removing the negative hydro O&M values results in an $8.1 million total company, $5.3 million Washington-allocated reduction to power costs in this proceeding.

<u>Dispatch Margin Calculation</u>

Q. WHAT IS THE DISPATCH MARGIN CALCULATION, AND HOW DOES IT IMPACT POWER COSTS?

A. The dispatch margin is an optional modeling parameter in AURORA that creates an additional variable cost adder that a resource must recover, above and beyond its own variable operating cost, in order to operate. The Company includes a 5 percent dispatch margin in this proceeding, which means that a Company resource with a variable cost of $40.0/MWH would not dispatch into the market until the price is $42.0/MWH ($40/MWH *1.05).

Q. WHAT IS YOUR VIEW OF THE PURPOSE OF THE DISPATCH MARGIN OPTION IN AURORA?

A. My understanding is that this modeling option is used when variable O&M values, and other variable costs adders, are not modeled explicitly within the individual resources in AURORA. The Company, however, already models all of the variable O&M, and other similar adders, in the individual resource assumptions in AURORA. So, in my view, it is not appropriate to include a separate adder in the dispatch margin option.

Q. DID YOU REQUEST FOR THE COMPANY TO EXPLAIN WHY IT MODELS A DISPATCH MARGIN IN THIS PROCEEDING?

A. Yes. In response to ICNU data request 5.15, the Company stated as follows:

> This dispatch margin in AURORA is an adder used to change the percent margin required for a dispatchable plant to commit to running. The adder is applied to all plants in the western interconnect and is used to adjust market prices to match forward

> price curves. Forward price curves typically have an implied risk premium when compared to spot prices; this margin adder aligns the predicted prices from AURORA with current forward prices for the 2015 rate year.[30/]

Q. DO YOU AGREE WITH THE COMPANY'S INTERPRETATION OF THE DISPATCH MARGIN PARAMETER?

A. No. I do not believe that it is appropriate to include an "implied risk premium" in the pro forma power costs calculated in the AURORA model. The Company is already insulated from the risks associated with its power supply through the mechanics of its ERM. Including a separate risk premium in power costs, in essence, causes customers to pay twice for the price risk associated with power markets— i.e., customers would pay the risk premium in base rates, yet assume all of the risk through the ERM.

Q. DID YOU ASK THE COMPANY TO JUSTIFY WHY IT USED 5 PERCENT, IN CONTRAST TO SOME OTHER VALUE, AS ITS DISPATCH MARGIN ASSUMPTION?

A. Yes. The Company stated that it "developed the margins included in the cases via an iterative process to align AURORA prices with forwards."[31/]

Q. DO YOU BELIEVE IT IS APPROPRIATE FOR THE COMPANY TO ARBITRARILY CHANGE AN INPUT PARAMETER IN ORDER TO FORCE THE MODEL TO PRODUCE A PARTICULAR MARKET PRICE?

A. No. As discussed in relation to variable hydro O&M, above, the model should be an unbiased indication of market prices. Simply forcing it to produce the results the Company wants defeats the purpose of having a model to begin with. If the market prices are known, power costs could be calculated outside of the AURORA model in an Excel spreadsheet. In addition, the Company suggests that the forward prices contain

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30/ Id. (the Company's response to ICNU Data Request 5.15).

31/ Id. (the Company's response to ICNU Data Request 5.16).

some sort of risk premium and, accordingly, are not representative of the cost the Company will incur when it will dispatch its resources in real time markets.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE DISPATCH MARGIN ASSUMPTION.

A. I recommend that it be removed from power costs in this proceeding.

Q. WHAT IS THE IMPACT OF REMOVING THE DISPATCH MARGIN PARAMETER FROM THE AURORA MODEL?

A. Removing the dispatch margin assumption from AURORA reduces power costs by $2.1 million total company, $1.4 million Washington-allocated.

<u>Phantom Congestion</u>

Q. WHAT IS PHANTOM CONGESTION?

A. Phantom congestion is a modeling technique used by the Company to constrain the modeled southbound capacity on the California-Oregon Intertie ("COI") below its actual transfer capability. According to the Company, it was designed to represent transmission capacity which is withheld by COI participants, but not ultimately scheduled in real time markets.[32/]

Q HOW DOES THIS MODELING TECHNIQUE IMPACT POWER COSTS CALCULATED IN AURORA?

A. Phantom congestion constrains the amount of energy that can be transferred from the Northwest into California below the actual limits of the COI. Accordingly, as less modeled energy from the Northwest can be exported into California, modeled market prices in the Northwest, and consequently power costs, increase.

[32/] Id. (the Company's response to ICNU Data Request 5.17).

Q. IS THE COMPANY'S MODELING CONSISTENT WITH HOW THE COI ACTUALLY OPERATES?

A. No. To the extent that the COI is congested, my understanding is that each of the participants will receive a reduced share in the COI transfer capability. Congestion, however, does not impact the overall transfer capability of the path into California. To the extent that a party reserves capacity on the COI, yet decides not to schedule that capacity, the overall path capacity does not change. It only means that it was not economic for that particular participant to send power into California. Accordingly, I do not believe that the actual operation of the COI warrants deration of the path capability in AURORA.

Q. HOW DID THE COMPANY DEVELOP THE LEVEL OF PHANTOM CONGESTION IT APPLIED IN AURORA?

A. The level of congestion assumed in the AURORA model was not based on any sort of study regarding the amount of historical congestion on the COI. Instead, the Company explained that it "arrived at its line de-rates via an iterative process to align AURORA prices with forward Mid-Columbia prices."[33/] In other words, the input values for phantom congestion were arbitrary and designed to force the model to produce a pre-determined price. To reiterate, the purpose of the Company's power cost forecasts in AURORA should not be to tie to the prices calculated in the model to market forwards. The purpose should be to capture the economics of system dispatch using unbiased and well-documented assumptions.

[33/] Id. (the Company's response to ICNU Data Request 5.18).

Q. HOW DO YOU RECOMMEND FOR PHANTOM CONGESTION BE HANDLED IN THE COMPANY'S MODELING?

A. I propose that the phantom congestion be removed from the model, until the Company can document that the level of transmission deration is reasonable, through a study or some other form of documentation.

Q. WHAT IS THE IMPACT OF REMOVING PHANTOM CONGESTION FROM THE AURORA MODEL?

A. Removing the phantom congestion assumption from AURORA reduces power costs by $2.3 million total company, $1.5 million Washington-allocated.

VI. RENEWABLE ENERGY CERTIFICATE PASS-THOUGH MECHANISM

Q. HAVE YOU REVIEWED THE COMPANY'S PROPOSED MECHANISM FOR RETURNING RENEWABLE ENERGY CERTIFICATE ("REC") REVENUES TO CUSTOMERS?

A. Yes.

Q. IS THE MECHANISM CONSISTENT WITH THE COMMISSION'S REQUIREMENTS AND REC REVENUE PRECEDENT?

A. No. While the mechanism may pass the revenues associated with REC sales through to customers in accordance with the Commission's requirements, the Company also intends to use the mechanism to pass the costs associated with future REC purchases onto customers.[34]

Q. IS THAT CONSISTENT WITH THE COMMISSION REQUIREMENT FOR A REC REBATE MECHANISM?

A. No. The Commission has determined that RECs are to be treated as property and, in accordance with its rules regarding the disposition of property, gains from the sale of

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34/ Exh. No.___(WGJ-IT) at 17.

RECs must be returned to customers. There is no requirement that the costs associated with the acquisition of RECs should be concomitantly recovered from customers through the Company's mechanism.

Q. DID THE COMPANY PROVIDE ANY JUSTIFICATION TO SUGGEST THAT IT WAS IN THE PUBLIC INTEREST TO DEFER FUTURE REC PURCHASES THROUGH ITS PROPOSED REC REBATE MECHANISM?

A. No. The possibility of including future REC purchases made to comply with Washington renewable portfolio standard requirements was mentioned parenthetically in the Direct Testimony of William G. Johnson.[35/] Accordingly, not enough information has been presented for the Commission to justify the inclusion of the costs associated with future REC purchases in the proposed REC rebate mechanism.

Q. WHAT IS YOUR RECOMMENDATION?

A. I propose that the Commission, in establishing a mechanism to return REC sales proceeds to customers, require the Company to exclude the cost of any future REC purchases from the mechanism. Because the Company is not forecasting any REC purchases prior to June 2013, this action will have no impact on the amount of deferred REC proceeds proposed by the Company in this proceeding.

VII. DECOUPLING

Q. HAS AVISTA PROPOSED A DECOUPLING MECHANISM IN THIS CASE?

A. Yes. Decoupling raises a number of issues that the Commission must decide. In this section of my testimony, I consider several reasons why decoupling should not be applied to the industrial customer class Schedule No. 25. ICNU witness Mr. Stephens discusses a

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35/ Id. at 17:5-6.

rate design proposal that will mitigate the need to apply decoupling to industrial customer classes, and Mr. Gorman discusses decoupling in the context of capital costs.

Q. WHAT IS ICNU'S PROPOSAL FOR DECOUPLING IN THIS PROCEEDING?

A. ICNU proposes that industrial customers be exempt from any potential decoupling mechanism approved by this Commission in this proceeding.

Q. WHY SHOULD INDUSTRIAL CUSTOMERS BE EXEMPT FROM A POTENTIAL DECOUPLING MECHANISM?

A. The application of a decoupling mechanism to industrial customer classes works counter to the purpose of such a mechanism. Industrial customer classes are distinct from other rate classes, in that they have relatively few customers and may be dominated by few, or, many times, a single customer. Accordingly, the changes of an individual customer's load within the industrial class can have a material impact on the class load as a whole. As a result, the application of a decoupling mechanism to industrial rate classes causes inequities between members of the class and eliminates any incentive for these customers to participate in cost effective energy efficiency programs.

Q. HAVE YOU PERFORMED ANY ANALYSIS TO DEMONSTRATE THE UNIQUE NATURE OF INDUSTRIAL CUSTOMER CLASSES?

A. Yes. The following table provides several statistics from the Company's filing comparing the residential rate class, Schedule No. 1, to the extra large general service rate class, Schedule No. 25.

TABLE 5
COMPARISON OF SCHEDULE NO. 1 AND SCHEDULE NO. 25

	Sch. 1		Sch. 25
Total Customers (Bills/Mo)	203,090		22
Total Usage (KWH)	2,356,720,794		1,080,448,696
Average Customer (KWH)	11,604		49,111,304
Average Co. % of Class	0.000%		4.545%
Largest Customer (KWH)	116,043	*	480,634,245
Largest Co. % of Class	0.005%	*	44.485%

**Assumed largest residential customer is ten times the average*

Q. WHAT DOES THIS TABLE DEMONSTRATE?

A. Table 5 demonstrates that no individual customer on Schedule No. 1 can materially impact the overall kilowatt per hour ("KWH") sales derived from the class as a whole. At most, a single Schedule No. 1 Customer could impact the overall KWH sales by five-one-thousandths of a percent. In contrast, the loss of the load from a single customer on Schedule 25 has the potential to reduce the overall KWH sales derived from that class by a material amount, nearly 45 percent.

Q. WHY IS THIS A PROBLEM UNDER THE COMPANY'S PROPOSED DECOUPLING MECHANISM?

A. The decoupling mechanism that has been proposed in this proceeding will guarantee that the Company recovery of a certain amount of fixed costs from each customer class, regardless of the level of KWH sales generated from that class. This means that the actions of an individual industrial customer could shift large amounts of fixed costs onto other customers in the class, creating intra-class inequity. Table 5, below, provides an illustration of how the loss of the largest customer in both the residential and industrial class would impact other customers in the class under the Company's proposed decoupling mechanism.

TABLE 6
ILLUSTRATION OF DECOUPLING IMPACT ON FIXED COSTS RECOVERY RESULTING FROM LOSS OF SINGLE CUSTOMER

	Ref	Sch. 1	Sch. 25
(a) Total Fixed Costs	Illustrative	100,000,000	45,000,000
(b) Forecast Sales (MWH)	Table 5	2,356,721	1,080,449
(c) Fixed Cost per MWH	(a) * (b)	42.43	41.65
(d) Lost Single Customer Load	Table 5	116	480,634
(e) Actual Sales (MWH)	(b) - (d)	2,356,605	599,814
(f) Actual Fixed Cost Recovery Before Deferral	(d) * (e)	99,995,076	24,981,890
(g) Decoupling Deferral	(a) - (f)	4,924	20,018,110
(h) Actual Fixed Cost Recovery	(f) + (g) = (a)	100,000,000	45,000,000
(i) Actual Fixed Cost per MWH	(h) / (e)	42.43	75.02
(j) % Increase in Fixed Cost Rates	(i) / (c) -1	0.0%	80.1%

As can be seen from the table, the loss of a single customer in Schedule 1 has no material impact on the fixed costs recovered from the remaining customers in that class. On the contrary, the loss of a single customer from Schedule No. 25 would result in an 80% increase to the overall fixed costs allocated to the remaining customers in that class. This illustration provides a view into the inequity and potential harm that could result if a decoupling mechanism is extended to industrial customer classes.

Q. WHAT IS THE COMPANY'S UNDERSTANDING OF THE PURPOSE FOR DECOUPLING?

A. As discussed in the Direct Testimony of Patrick D. Ehrbar, the purpose of the decoupling mechanism is to insulate the Company from the effects of pursuing cost effective conservation.[36] The Company claims that energy efficiency measures, while reducing the Company's overall cost, reduce its KWH sales and result in under recovery of fixed costs billed on a volumetric basis.

Q. HAS THE COMPANY DEVELOPED ITS MECHANISM ONLY TO CAPTURE CHANGES IN LOAD RELATED TO ENERGY EFFICIENCY?

A. No. The Company's proposal captures changes in normalized load, regardless of whether those changes are related to energy efficiency. This is problematic for industrial rate classes, whose loads are principally driven by economic conditions, not energy efficiency programs. By including all forms of load deviation in its mechanism, the Company is essentially shifting load forecast risk onto customers.

Q. DOES A DECOUPLING MECHANISM ENCOURAGE INDUSTRIAL CUSTOMERS TO PURSUE CONSERVATION MEASURES?

A. No. On the contrary, the Company's proposed mechanism will actually provide an incentive for industrial customers not to participate in energy efficiency. Under the Company's proposed mechanism, industrial customers will be worse off on a per-KWH basis if their loads decline. Accordingly, these customers, which can independently impact the level of KWH sales derived from the class as a whole, may not be willing to be involved in conservation programs if they are aware that doing so will result in an increase in their rates through the proposed decoupling mechanism.

Q. PLEASE SUMMARIZE WHY YOU BELIEVE INDUSTRIAL CUSTOMERS SHOULD BE EXEMPT FROM ANY POTENTIAL DECOUPLING MECHANISM.

A. Industrial customer classes are unique. They have large customers who are capable of shifting large amounts of costs to other customers within the class through the mechanics

[36] Exh. No. ___(PDE-1T) at 49-50.

of the Company's proposed decoupling mechanism. While the purpose of a decoupling mechanism is to encourage cost effective conservation measures, application to industrial customers will work contrary to that goal. Under the Company's proposed mechanism it will not be economic for industrial customers to perform conservation measures and, as a result, they will have a reduced incentive to participate in self-directed conservation, as well as Company funded conservation measures. Large industrial customers currently have conservation measures in place and due to their large bills have an independent incentive to engage in conservation. Other mechanisms, such as the rate design proposed by Mr. Stephens, can achieve the goals of decoupling without causing unintended disincentives to conservation or creating the risk of extreme intra-class inequity.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.