BEFORE THE WASHINGTON STATE
UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. AVISTA CORPORATION, d/b/a AVISTA UTILITIES, Respondent.	)	DOCKETS UE-090134 and UG-090135 *(consolidated)*
In the Matter of the Petition of AVISTA CORPORATION, d/b/a AVISTA UTILITIES, For an Order Authorizing Implementation of a Natural Gas Decoupling Mechanism and to Record Accounting Entries Associated With the Mechanism.	)	DOCKET UG-060518 *(consolidated)* POST-HEARING BRIEF OF AVISTA CORPORATION

DAVID J. MEYER
V.P. and Chief Counsel For Regulatory and Governmental Affairs
AVISTA CORPORATION

TABLE OF CONTENTS

BEFORE THE WASHINGTON STATE
UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. AVISTA CORPORATION, d/b/a AVISTA UTILITIES, Respondent.	DOCKETS UE-090134 and UG-090135 *(consolidated)*
In the Matter of the Petition of AVISTA CORPORATION, d/b/a AVISTA UTILITIES, For an Order Authorizing Implementation of a Natural Gas Decoupling Mechanism and to Record Accounting Entries Associated With the Mechanism.	DOCKET UG-060518 *(consolidated)* POST-HEARING BRIEF OF AVISTA CORPORATION

1 COMES NOW, Avista Corporation (hereinafter "Avista" or "the Company"), by and through its undersigned attorneys, and respectfully submits this Post-Hearing Brief in the above-captioned matter.

I. INTRODUCTION

A. Procedural History.

2 On January 23, 2009, Avista filed tariff revisions meant to implement a general rate increase of $69.8 million, or 16%, for electric service and $4.9 million, or 2.4%, for natural gas service. As part of its filing, Avista also proposed to decrease the current Energy Recovery Mechanism (ERM) surcharge by $32.4 million, or 7.4%, resulting in an overall net increase of 8.6% for electric rates. The Commission suspended the operation of the proposed tariffs on February 3, 2009, and set the matter for hearing in October of 2009. (See Order 01/Order 02)

3 Subsequently, on May 15, 2009, the Commission consolidated the Decoupling docket into the general rate cases, in accordance with Avista's request. (See Order 06) The Commission

later granted Avista's request for an interim extension of its existing pilot Decoupling Mechanism pending entry of a final decision in the natural gas rate case. (See Order 07)

4 Finally, on September 4, 2009, the parties filed a Partial Settlement Stipulation[1]. The proposed Stipulation, if approved by the Commission, would resolve issues relating to cost of capital, power supply, rate spread and rate design, and low income ratepayer assistance.[2] The remaining issues were the subject of evidentiary hearings on October 6 through 9, 2009, and include various disputed revenue requirement items, the inclusion of costs relating to the Lancaster Power Purchase Agreement (PPA), and various issues surrounding the Decoupling Mechanism.

B. Revisions to Revenue Requirement, as Case Evolved.

5 At the outset, it may prove helpful to reexamine the positions of the parties with respect to revenue requirement, as this case progressed through the discovery and settlement processes. For Avista's part, it filed for $69.8 million of electric rate relief, but reached a proposed Partial Settlement (Exh. B-1) that reduced the request to $38.6 million. Subsequently, Avista filed rebuttal testimony that reflected further revisions lowering Avista's revenue requirement to $37.5 million for electric operations. (See Exh. EMA-4TC) With respect to natural gas, Avista originally proposed a $4.9 million revenue requirement increase, which was reduced to $3.1 million in the proposed Partial Settlement. On rebuttal, Avista further reduced its request to $2.8 million. (Exh. EMA-4TC) Attached as an Appendix A to this Brief is Avista's Response to Bench Request 3 (Exh. B-2) which identifies revisions to the revenue requirement for electric

[1] Only the Northwest Energy Coalition (NWEC) was not a signatory to the proposed settlement, but otherwise indicated that it did not oppose its terms.

[2] Public Counsel, however, reserved the right to contend that there should be a reduction to Avista's approved return on equity, as reflected in its cost of capital, resulting from any continuation of the Decoupling Mechanism. (See Exhibit MPG-1T).

and gas operations as a result of the Partial Settlement, and as finally reflected in Avista's rebuttal testimony.

6 For its part, Staff has revised its proposed electric revenue requirement to approximately $24.2 million and its natural gas revenue requirement to $613,000, as reflected in Exhibit B-4. Public Counsel has submitted a number of iterations of its proposed revenue requirement, with its most recent portrayal set forth in Exhibit B-5, wherein it proposes a $3.9 million increase in electric revenue requirement and a $869,000 increase in Avista's natural gas revenue requirement. (See also, Appendix B, for a tabular summary of the parties' positions).

1. Avista's Request Put Into Perspective.

7 Before discussing the issues that remain, it is important at the outset to put Avista's proposed request into perspective. Avista understands that very difficult economic circumstances face many of our customers. These are challenging times, and Avista has responded with its own cost-saving initiatives which will be discussed below. Nevertheless, for purposes of this filing, Avista has proposed a sensible way to mitigate the net impact on customers, by reducing the existing surcharge meant to recover deferred power costs at the same time as the new rates, as approved by the Commission, go into effect. Were the Commission to grant the entirety of Avista's $37.5 million electric request, this would represent approximately a 9.5% change in base rates. However, in its filing, Avista proposes to offset much of this with a $28 million reduction in the existing surcharge, which is otherwise meant to recover deferred power costs, doing so at the same time the rates would go into effect in this case. The net impact experienced by customers would be approximately a 2.2% increase in billed rates in December of this year.

($37.5 million - $28 million = $9.5 million or a 2.2% increase in billed rates.)[3]

8 Staff and Public Counsel, however, for their part, would propose to <u>delay</u> any netting of the general rate case and the reduction in the ERM surcharge. The result would be that rates would increase in December of 2009 by whatever amount is approved by the Commission in this general rate case; subsequently in January/February, they propose to reduce the ERM surcharge to zero, to reflect zero balances anticipated at that time. The unfortunate result would be to increase general rates by as much as 9.5% in December (assuming Avista is granted its entire request), only to subsequently reduce customer rates, by the elimination of the surcharge, by approximately 9% in the next few months. This, of course, would deprive customers of the benefit of <u>netting</u> the two, as early as December of this year, and during the midst of the December/January heating season. From a customer's perspective, this makes no sense.

9 With respect to Avista's proposed natural gas increase, the revised request of Avista stands at $2.8 million, which represents approximately a 1.4% increase in base rates. Fortunately, however, the Company has received Commission approval to reduce its Purchase Gas Adjustment (PGA) rates by 25.9% effective November 1, 2009, which will help ameliorate whatever net impact is experienced by customers. (Avista understands the difference between an increase in base rates and the pass-through of costs relating to purchased gas in a PGA; nevertheless, the fact remains that the impact of any increase in base rates for natural gas service will be offset during the winter heating season.)

2. <u>Overview of Proposed Settlement</u>.

10 The Partial Settlement Stipulation (Exh. B-1) resolves a number of issues as between the parties, and represents a true give-and-take in the negotiation process. Stated differently,

[3] The reduction in the ERM surcharge rate would not entirely eliminate the anticipated ERM balance as of December 31, 2009, which is expected to remain at $4.5 million. As explained by Company Witness Norwood, the Company would propose to amortize this over a 12 month period in 2010, resulting in a modest continuing ERM surcharge of approximately 1%. (Exh. KON-1T, pg. 31).

agreements with respect to any particular element of the Settlement were bargained for and negotiated in the context of the overall Stipulation.

11 The Settlement would resolve cost of capital issues, by establishing an authorized return on equity of 10.2%, and reflecting an equity component of the capital structure of 46.5%, resulting in an overall proposed rate of return of 8.25%. These agreed-upon elements closely approximate Avista's currently authorized cost of capital.[4] (It is understood that Public Counsel will assert that at least the gas return on equity should be adjusted downward to reflect what Public Counsel perceives as a lower risk, if the Decoupling Mechanism is continued. Avista will address this later in the Brief.)

12 With respect to power supply issues, the Settlement resolves all issues, except for inclusion of the Lancaster PPA in rates, which only Public Counsel continues to challenge. The most significant agreed-upon power supply-related issues pertain to updated natural gas prices and a reduction in pro forma retail load. Whereas Avista had originally included a pro forma natural gas price of $7.83/Dth at the time of its filing, the parties have agreed to adjust the pro forma natural gas price for the unhedged portion of its supply to $5.61/Dth. As shown in the attachments to Avista's Response to Bench Request No. 3 (see Appendix A to Brief), the adjustment to natural gas prices and contracts, in and of itself, reduced Avista's revenue requirement by $18.1 million.

13 The next most significant element of the power supply adjustment related to a downward adjustment in retail loads from 5% to approximately 2% (a 3% reduction) from the end of the test period through the rate effective period. This served to further reduce the power supply-related revenue requirement by approximately $9 million. (Id.)

[4] Avista's currently-authorized return on equity is 10.2%, its equity component of the capital structure is 46.3% and its overall authorized rate of return is 8.22%.

14 With respect to rate spread and rate design issues, the Settlement provides for an equal percentage increase to all schedules with respect to electric service and an equal percentage of margin increase to all schedules with respect to natural gas service.[5] The parties have agreed to increase the electric basic charge from $5.75 to $6.00 per month, but continue to disagree with respect to the gas basic service charge: The Company had proposed a similar increase of $5.75 per month to $6.00; however, Staff has proposed a much more significant increase to the gas basic charge, in lieu of continuation of the Decoupling Mechanism. (Staff proposes an adjustment that would ultimately increase the basic charge to $10 per month, assuming that Decoupling is terminated.) The only other changes with respect to rate design are with reference to Extra Large General Service Schedule 25, which are described in the Stipulation. (See Exh. B-1) Finally, the parties have agreed to increase the low income rate assistance program (LIRAP) funding by the greater of the overall percentage increase in base revenues or 9%, for electric service; for natural gas service, the funding would increase by the greater of the overall percentage increase in base revenue or 1.75%.

C. <u>Avista, For Its Part, Has Implemented Cost-Cutting Measures</u>.

15 It is fair to ask whether Avista, itself, is doing its part to manage its costs. We understand that these are difficult economic times for our customers and that they are doing what they can to cut costs, and they should expect the utility to do the same.

16 Avista has responded, in that regard (as will be discussed below), but at the outset it should be recognized that, in the final analysis, Avista has a continuing "obligation to serve" its customers with safe and reliable service. To that end, it simply cannot refuse to spend money, where required, to maintain its facilities and to invest in new infrastructure to serve its load. Not only do reliability mandates require this, but our customers have come to expect this. Stated

[5] The one exception relates to Transportation Service Schedule 146, which would receive an increase of two-thirds (2/3) of an equal margin increase.

differently, unlike a national retail chain that can simply close down underperforming stores or discontinue entire product lines, in order to save costs, Avista cannot do so. (Tr. p. 473, ll. 6-11) Consistent with its "obligation to serve," it cannot decide to serve only a portion of its territory because its cost characteristics, or needs for infrastructure enhancements are too great. Without belaboring the obvious, any cost cutting that Avista does must still be consistent with its continuing "obligation to serve."

17 So what has Avista done in that regard? Beginning with the direct testimony of Scott Morris (Exh. SLM-1T, pp. 6-9), the Company has described a number of measures to mitigate the impact of increased costs on our customers. These include, in no particular order of importance, the cancellation of a new office building on the campus grounds in order to meet expanded needs for space; the outsourcing of its billing and mailing services, the use of additional online service offerings, in order to reduce the level of the Company's Contact Center staffing. Other measures addressed by Company Witness Kopczynski (Exh. DFK-1T) include the use of "mobile dispatch" in order to allow for more effective use of crew availability and time; the employment of refined "outage management tools" to allow for quicker and more efficient restoration of electric service; and better coordination of regional infrastructure development, with local governments. The important point is this, cost cutting is not something that the Company is only now starting to engage in; rather, following the energy crisis of 2000/2001, and as explained by Company Witness Morris, we began cutting our operating expenses as we worked toward regaining our investment grade credit rating. (Exh. SLM-1T, p.8, ll. 30-35)

18 Mr. Norwood, on behalf of Avista, at the time of the October hearings responded directly to the question of what Avista has done, by way of controlling its costs:

19 . . . I would like to respond to that now, because we hear that from our customers, we're talking with our customers and we listen to them. There are a number of things that we have done and that we're continuing to do. One is we have a hiring restriction in place right now. No positions can be filled, whether that's because of retirement or someone leaving the Company, can be – those positions can't be filled unless they're approved by the Chairman of the Board, so it's the highest level that has to approve all the [hiring] . . .

20 Capital budgets for 2009 originally came in at $270 Million and senior management cut that down to $210 Million. Later the board cut it back to $202 Million, so that we have cut our capital budgets. Salaries for 2009, there was no increase for officers for 2009, the increase for other employees was also cut back from 3.8% to 2.5%. For 2009 we cut 52 positions from our operations group, just find a way to get the work done with fewer bodies. The existing building was built in 1958. We added onto it in 1978. We've gone 30 years without adding space. We have desperately needed more space. We had drawn up plans to build another building on the same site there for more space. We cancelled that because of the costs and the economy. We found a place 9 miles away that we could buy at a very low cost, and we moved people out there, which is not ideal, but it's a lower cost than simply building another building. We have outsourced our billing system in the last year. We had a new requirement to have disaster recovery. Rather than add costs, we outsourced our billing as well as providing disaster recovery for a lower cost. (Emphasis added)

(Tr. p. 469, l. 21, p. 471, l. 6)[6]

21 He makes it clear that the Company continues to employ limitations on hiring and has cut its proposed capital budgets to levels below what various departments within the Company would recommend (i.e., the 2009 capital budget was trimmed from $270 million to $202 million). (Id.) Lastly, in terms of the compensation of senior executives and other members of management, the Company has been careful to appropriately allocate only a fair portion of these expenses to ratepayers. (For example, although the Company's most recent proxy reports total

---

[6] Mr. Norwood also elaborated on other revenue-producing initiatives undertaken by the Company for the benefit of customers:

> A couple other things that we are doing that really demonstrate I think our effort to try to keep our costs low. Several years ago we worked with California to qualify our hydro plants on the Spokane River as certified renewable resources in the State of California, and because of that we were able to sell some of our surplus energy to California under that program and achieve $5.8 Million per year of additional margin which is reflected in this case and being credited back to customers. We've also gone after one example in the State of Montana who needs load following services, and so we are selling more load following services, and that's bringing in about $4.9 Million per year which is going back to customers.

(Tr. p. 471, ll. 7-21). (Emphasis added).

compensation for Mr. Morris that exceeds $2 million, $433,000 of his salary and incentives were allocated to ratepayers in the State of Washington as part of this filing, and were not challenged by any party.) (See Exh. B-17)

II. <u>THE LANCASTER POWER PURCHASE AGREEMENT (PPA) WAS A PRUDENT ACQUISITION AND SHOULD BE IMMEDIATELY RECOGNIZED IN RATES.</u>

A. <u>Introduction: Description of the Plant</u>.

22 The Power Purchase Agreement for the Lancaster Generating Facility (Lancaster PPA) is a "tolling arrangement" for a combined-cycle gas-fired plant. This plant is located in the Company's service territory near Rathdrum, Idaho, and is immediately adjacent to Avista's facilities. (Exh. RLS-1T, p. 8, l. 14, p. 9, l. 8)[7] (See also Exh. RLS-3 for an illustration of the Lancaster facility and a map of its location.)[8]

23 As discussed below, subject to regulatory approval of its cost recovery, the Lancaster PPA will become a utility resource on January 1, 2010. Accordingly, the Company has included the revenues and expenses associated with the Lancaster PPA as part of its pro forma power supply adjustment.

24 This resource acquisition was timely, and met the long-term resource needs set forth in the Company's 2007 IRP which indicated that a 350 MW natural gas-fired base load resource was needed in the 2008-2017 timeframe. (Exh. RLS-1T, p. 9, ll. 11-19)[9] As explained by Company Witness Storro, there are three main components to the Lancaster acquisition. (See Exhibit RLS-1T, p. 10) First, there is the actual Power Purchase Agreement (PPA), itself, which

---

[7] Indeed, on cross examination, Company Witness Storro observed that the plant is within 300 feet of Avista's own transmission network. (Tr. p.775, ll. 14-16).

[8] The facility is a General Electric Frame 7 FA Turbine that went into commercial service as a merchant plant in September 2001. It is a 245 MW gas-fired combined-cycle combustion turbine (CCCT), with an additional 30 MWs of duct firing capability. (<u>Id</u>.) In 2006 it had an average net heat rate of 6,925 btu/kWh, and an average equivalent availability of 92.9%. (<u>Id</u>.)

[9] The first decade of the Company's Preferred Resource Strategy in its 2007 IRP included a mix of 87 MW of DSM, upgrades to existing plants, 350 MW of gas-fired CCCT, 300 MW of wind, and 35 MW of other renewable generation (such as small co-generation, biomass and geothermal). (Exh. RLS-1T, p. 5, ll. 13-16).

was made available to the Company on January 1, 2010, for a period extending to October 31, 2026. As such, it is a long-term resource acquisition in the form of a power purchase agreement. It is a "tolling agreement" whereby, in exchange for the payments outlined in the PPA, Avista has the right to dispatch the plant. This requires the Company to arrange and pay for natural gas fuel procurement and transportation to the Lancaster plant, as well as subsequent transmission to move the power from the plant. In turn, the Company is entitled to the entire electric capacity and energy output from the plant. (Id.) (This Brief will later explain why this "tolling arrangement" is fundamentally different from a "commodity transaction.")

25 Secondly, the Lancaster plant is interconnected with the Gas Transmission Northwest (GTN) natural gas pipeline system. Commencing January 1, 2010, the Company will receive the assignment of natural gas transportation capacity under various firm transportation agreements described in the testimony of Mr. Storro, all of which will allow for deliveries to the plant. (Id.)

26 Lastly, at present, the Lancaster Plant is physically interconnected with the Bonneville Power Administration (BPA). The existing Transmission Agreement with BPA calls for 250 MWs of long-term transmission capacity rights from the Lancaster Plant (as the point-of-receipt) to the John Day point-of-delivery. As was true with the gas transportation contracts, this BPA Transmission Agreement was assigned to Coral Power on a short-term basis through December 31, 2009, after which there will be a permanent assignment of these rights to Avista Utilities, subject to receipt of necessary regulatory approvals. (Id.)

B. Sequence of Events Regarding Acquisition of Lancaster PPA.

27 Company Witness Storro, in both his direct testimony and on cross-examination, explained the sequence of events in early 2007 that led to the utility's decision to acquire the Lancaster PPA. He explained that the utility was presented with the opportunity in late March/April of 2007 to acquire the PPA from Avista Energy. Mr. Storro and his resource planning department were asked to examine whether this resource would meet the needs of Avista's customers, and on April 11, 2007, the utility completed an initial assessment of the Lancaster PPA utilizing the 2007 IRP model. (Exhibit RLS-1T, p. 9, ll. 11-20) This initial assessment, as set forth in Exhibit RLS-4, concluded that this resource addressed the Company's long-term capacity and energy needs, which, as indicated above, called for a 350 MW natural gas base load resource in the 2008-2017 time frame. (RLS-1T, p. 9, ll. 13-16)

28 This initial analysis, as performed by the Company's resource planning staff, was based on the 2007 IRP models and methodologies, which indicated energy deficits in 3 of the 4 quarters beginning in 2010 (excluding the second quarter capturing spring-runoff months). Capacity deficits were 146 MW in 2011 and grew into the future. (Id.) Accordingly, the energy and capacity deficits, combined with an IRP that called for a 350 MW baseload natural gas-fired resource, made the Lancaster PPA a very attractive resource selection for Avista and its customers. (Id. at p.11, ll. 6-13)

29 More particularly, this April 11, 2007 internal study (RLS-4) identified all of the natural gas-fired combustion cycle plants located in the Northwest for purposes of comparison to Lancaster. As explained by Mr. Storro, of the 13 plants identified, only 4 of those plants were not already owned by utilities. (Exh. RLS-1T, p. 11, ll. 15-20) According to Mr. Storro:

30

> None of these [utility-owned] plants were known to be for sale at the time the study was completed. This essentially ruled out the purchase of a Brownfield site. However, the study was conducted with the assumption that a Brownfield site was available. Brownfield site costs were chosen based on a review of the most recent plant purchases in the Pacific Northwest.

(Exh. RLS-1T, p. 11, l. 20 – p. 12, l. 2)

31 The April 11, 2007 internal study demonstrated that the acquisition of this PPA beginning in 2010 showed a positive benefit to the Company and its ratepayers unless a Brownfield project of less than $550 kW were located; but as testified to by Mr. Storro, the Company was not aware of availability of any such projects at the time, nor has the Company identified any projects "in this price range since the study was completed." (Id. at p. 12, ll. 3-8) It is well to note that, not even Public Counsel, as the lone opponent of the PPA, could identify a single gas-fired resource that could have been acquired by the Company at a more attractive price. (See Tr. p. 933) Finally, as discussed above, the Lancaster PPA also provided a significant benefit relative to the construction of a new Greenfield plant. As show in Mr. Kalich's rebuttal testimony, and as discussed later in this Brief, the average project costs for other plants after the construction of Lancaster shows an average cost of $1,121 kW – i.e., more than twice the cost of Lancaster. (Exh. CGK-4T, p. 12)

32 Even though the sale of Avista Energy was publicly announced at the end of April of 2007, and the decision was made to transfer the Lancaster PPA to the utility, effective January 1, 2010 (subject to regulatory approvals), the Company nevertheless requested that an independent third party review its April analysis. Accordingly, in August of 2007, Avista contracted with Thorndike Landing, LLC, for an independent assessment of the Lancaster PPA relative to other utility gas-fired plants.[10] Thorndike also reviewed the Company's analytical processes used for the Lancaster evaluation, as well as resource planning in general. (Exh. RLS-1T, p. 12, ll. 10-19) That independent study was completed in October of 2007 (see Exh. RLS-5), and concluded that the Lancaster PPA was cost-effective and was financially more favorable relative to other natural gas-fired options available to utilities in the Pacific Northwest. (Id.) Mr. Storro describes this analysis in more detail in his direct testimony. (Exh. RLS-1T, pp. 13-15) Thorndike Landing specifically ". . . found that the Toll provides positive value to Avista and its customers . . . and the value of the Lancaster facility appears consistent with – if not greater than – the value of

[10] As explained by Company Witness Storro, this independent study used 4 different valuation metrics and perspectives, including discounted cash flow analysis, valuation under a purchase scenario, identification and valuation of similar assets, and a review of similar market transactions in the region.

other resources in the market." (See Exh. RLS-5, p. 1) Thorndike also concluded that Avista's analytical process and valuation methodology were quite sound:

> 33 Thorndike Landing has reviewed Avista's analytical methodology and has found that Avista's analytical process and methodology is a very contemporary approach to analyzing resources. . . . Additionally, Avista's process is also grounded on sound resource planning using multiple scenarios and a robust vs. static process through which the Company is able to assess multiple scenarios and resource portfolios, not just a single resource in isolation. For these reasons, we have found that Avista's analytical process is sound and even surpasses processes used by many of their peers across the industry. Therefore, we have not identified any area or aspect of its process generally for which we would suggest modification at this time. (Emphasis added)

(Exh. RLS-5 at p. 15) Thorndike then went on to elaborate on its conclusion with respect to benefits inuring to customers from this transaction:

> 34 In conclusion, Thorndike Landing believes that the transaction for the Toll is reasonable and that the value Avista would remit for the toll is reasonable and would result in a net benefit to Avista and its customers. Further, based on our analysis and assumptions, the value of the Lancaster Facility appears to be greater than that of other recently constructed or transacted facilities in the region. . . .

(Exh. RLS-5, p. 19)

35 Mr. Storro nicely summarized the conclusions of both the internal and external studies that had been conducted regarding the Lancaster PPA:

> 36 Both the internal and external studies regarding the Lancaster PPA showed that the PPA was cost-effective when compared to similar base load resources and is needed for utility service based on the Company's load and resource position, and fits within the resource guidelines established by the 2007 IRP. The cost-effectiveness of the PPA included an analysis of the associated natural gas transportation and electric transmission agreements. Furthermore, the Lancaster PPA provides the Company with the ability to operate the plant in a flexible manner consistent with an owned-plant and the PPA stipulations provide protections against losses due to mechanical failures at the facility.

(Exh. RLS-1T, p. 16, ll. 20-26) (See also Exh. RLS-6, consisting of a white paper that summarizes the Lancaster studies).

37 It is important to understand the timing and sequence of events that occurred in 2007. As discussed above, the resource department of Avista Utilities was presented with an opportunity to acquire the Lancaster PPA on January 1, 2010, as part of a sale of assets that was being negotiated by Avista Energy at the time. There was a very narrow window of opportunity within which Avista Utilities could act, given the pending sale of Avista Energy. As noted above, the resource department completed its analysis on April 11, 2007. By the end of April, Avista Energy had publicly announced that it was selling its assets to Coral Energy, effective June 30, 2007. The important point is this: If Avista Utilities had not acted, when it did, to acquire this resource on behalf of its ratepayers, nothing would have prevented Avista Energy or Avista Turbine Power (which held the assigned Lancaster PPA) from selling this long-term purchase power agreement to another party.[11] Stated differently, Avista Energy and its affiliate, Avista Turbine Power, were not required to transfer the benefits of this long-term PPA to the utility, and could have gone elsewhere to extract value from this low-cost resource. Instead, it was agreed that this PPA would be temporarily assigned to Coral Power LLC for a 2 1/2 year period from June 30, 2007 through December 31, 2009, at which time the PPA would be re-assigned to Avista Utilities (assuming appropriate regulatory treatment). (See Exh. RLS-19-X, for a schematic showing the sequence of transactions.) If Avista Utilities had passed on this opportunity, given this narrow window of opportunity, it would still have been in the market for a similarly-sized combustion turbine to meet the defined long-term needs of both its 2007 and 2009 IRPs – and would have been doing so at a higher cost, as demonstrated by Mr. Kalich in his rebuttal testimony. (Exh. CGK-4T)

38 There was neither the time for, nor the requirement to obtain, a formal Request for Proposal (RFP). First of all, contrary to Public Counsel's suggestion, Avista did not violate the

[11] Later in this Brief, Avista will discuss the "at cost" nature of this transfer of the PPA to Avista Utilities.

provisions of WAC Chapter 480-107 with respect to the need for an RFP.[12] It should be remembered that Avista's 2007 IRP identified the need for more than 300 MW of gas-fired CCCT generation. As testified to by Mr. Kalich, the Company made "an extensive effort to assess the marketplace and determine what other purchases might be available, including long-term contracts and existing and new CCCT plants." (Exh. CGK-4T, p. 8, ll. 6-10) He went on to observe that "market surveys and regional planning estimates were used to supplement the Company's overall knowledge of the resources available in the northwest marketplace." (Id.) This led Mr. Kalich to conclude that:

39 > The IRP work, and all information in the marketplace, indicated that the price of Lancaster was very attractive relative to other options. First, regional planning documents showed the cost of new CCCT plants to be 50% more than Lancaster. Second, there were a number of CCCT acquisitions made around the time of the decision, and Lancaster was at the low end of the acquisition price. Third, there were very few CCCT plants not already owned by a utility company or under long term contracts, and there were no such plants available for acquisition.

(Exh. CGK-4T, p. 8, l. 22 – p. 9, l. 6)

40 Moreover, the recent history of acquisitions of combustion turbine projects in the Northwest involving other utilities confirms that very few have been pursuant to a formal RFP. (See Tr. p. 883) Furthermore, even if one were to have pursued an RFP, such a process could have taken up to nine months to complete (see Tr. p. 813), and the sequence of events, and the short window of opportunity in which to act by Avista Utilities, would not have allowed for such an extended process. (Avista and other utilities, such as Puget Sound Energy (Mint Farm) have

---

[12] WAC 480-107-015(3)(a) provides:

> (3) Timing of the solicitation process.
>
> > (a) The rules in this section do not apply when a utility's integrated resource plan, prepared pursuant to WAC 480-100-238, demonstrates that the utility does not need additional capacity within three years.

Accordingly, WAC Ch. 480-107 requires the issuance of an RFP after the publication of an Integrated Resource Plan (IRP) identifying a capacity deficiency <u>within three years</u> of its publication. At the time of the IRP filing, Avista's capacity need, even absent Lancaster, was further into the future than 3 years. (Exh. CGK-4T, p. 8) been "opportunistic" in this regard). Moreover, Staff Witness Buckley made it clear in his testimony that "none of the companies are required to file an RFP before acquiring a resource," so long as "they provide all the information and their justification for doing so." (Tr. pp. 958-959)

41 Finally, before concluding this discussion of the sequence of events, Avista will address Chairman Goltz's question that he posed at the conclusion of the hearing – namely, what significance, if any, should the Commission assign to the fact that there is no contract, per se, that requires Avista Turbine Power to assign the Lancaster PPA to Avista Utilities on January 1, 2010, after it reclaims the 2½ year assignment to Coral Power LLC?[13] (See Tr. p.1228, ll.14-18)

42 At the outset, it should be noted that Avista has been quite clear throughout these proceedings regarding its intent to actually acquire the Lancaster PPA, effective January 1, 2010, subject to acceptable regulatory treatment. (See Direct Testimony of Company Witness Storro, Exh. RLS-1T, p. 9): "Lancaster will become a utility resource on January 1, 2010 . . ."). Moreover, in its various public disclosures to investors, such as its annual Form 10-K Report, Avista has informed the public that it intends to acquire the Lancaster PPA, effective January 1, 2010, subject to appropriate regulatory treatment. Therefore, there should be no confusion surrounding Avista Utility's stated intent or desire to make use of the Lancaster PPA for the benefit of its ratepayers.

43 But does it matter that there is not a document (i.e., a "piece of paper") that obligates Avista Utilities to take this assignment of the Lancaster PPA on January 1, 2010? The short answer is, no, it does not. Avista Corporation will follow through with the necessary contractual assignment of the Lancaster PPA on January 1, 2010, subject to the receipt of the requested

[13] Chairman Goltz inquired as to ". . . whether it makes a difference that there does not appear to be a contract between Avista Turbine and Avista Utilities." (Tr. p. 1228, ll. 17-19)

ratemaking treatment.[14] That is consistent with its stated intent, both within these hearings, and with the public-at-large. Avista Corporation (doing business as "Avista Utilities") is the sole shareholder of Avista Turbine Power LLC (which would reacquire the Lancaster PPA from Coral on December 31, 2009). As the sole shareholder, Avista Corporation can simply direct Avista Turbine to transfer the PPA to Avista Utilities, effective January 1, 2010. This reassignment can be quickly and easily accomplished, and would be in the nature of a "ministerial act" to carry out the stated intent of Avista. Because such a transfer, however, was always predicated on the receipt of acceptable ratemaking treatment, it was never necessary to create such an obligation to transfer until such time as this Commission ruled with respect to the appropriate ratemaking treatment, and could be easily "unwound" if that approval was not forthcoming. (Even if there had been such a prior obligation on the part of Avista Turbine to transfer the PPA to the utility, that surely would have been conditioned on the receipt of the requested ratemaking treatment. Either way, one arrives at the same result, with or without such a contract in place. In a sense, this is "housekeeping.")

44 The important point is this: By design, there is no contractual obligation on the part of Avista Utilities to take Lancaster PPA, absent acceptable ratemaking treatment. Avista Turbine Power and Avista Corporation would be free to transfer this long term PPA to a third party, recognizing that the value to a third party would be based on its long-term firm capacity and energy deliverability until the year 2026. In sum, the short answer to Chairman Goltz's question is that the absence of such a contract to reassign the PPA to Avista Utilities does not matter.

[14] Consistent with the commercial arrangements previously used to transfer the Lancaster PPA to both Avista Energy (6/15/00-6/30/07) and Coral Power (6/30/07-12/31/09), Avista Turbine Power will enter into a Power Purchase Agreement with Avista Corporation pursuant to which Avista Turbine Power will transfer the right to all of the capacity and all of the electrical output from the Lancaster project under the Lancaster PPA to Avista Corporation for the period of 1/1/2010-10/31/2026, and Avista Turbine Power will designate Avista Utility's generation control center as the control center for the dispatch of the Lancaster project under the Lancaster PPA.

Avista will either take the necessary steps to cause Avista Turbine Power to assign the PPA to Avista Utilities or not, depending on the outcome of these proceedings.

45 And if Avista's requested ratemaking treatment, allowing for the recovery of costs beginning in 2010 is approved by the Commission, consistent with its stated intent, there would be no reason for Avista to do otherwise than to cause the PPA to be transferred to the utility.[15] Avista Utilities needs the long-term resource, it wants this resource for the benefit if its ratepayers, and if it must look elsewhere, the record is replete with evidence that other CCCT's (which are the resource of choice) would be far more expensive. (See discussion infra.)

46 Lancaster represents a long-term, low-cost resource for Avista's customers, and it is appropriate for the costs associated with the resource to be reflected in rates through this proceeding.

C. <u>The Transfer of the Lancaster PPA to Avista Utilities Will Be "At Cost".</u>

47 The Lancaster PPA's cost of $550 per kW essentially reflects the original costs of constructing the Lancaster plant, that went into service in September of 2001. Those costs, as explained by Mr. Kalich, are much lower than the costs to subsequently construct a Greenfield project in 2010. When Avista Energy first acquired the rights to the Lancaster PPA (and subsequently reassigned it to Avista Turbine Power), the costs reflected the original costs of constructing the plant. If approved by the Commission, the Lancaster PPA will be transferred to Avista Utilities at the same level of costs, established nearly a decade ago.[16] This is reflected in the contractual documents set forth in Avista's Response to Bench Request No. 10. (Exh. B-11C) Stated differently, as part of the negotiated sale of Avista Energy's assets in 2007, it was agreed

[15] RCW 80.16.020 and WAC 480-100-245 require a utility to file a copy of a contract with an affiliated interest prior to its effective date. Although the details of the Lancaster transaction have already been fully disclosed and examined in this docket, Avista will file a copy of the contracts to effectuate the transfer to the utility prior to the January 1, 2010 effective date and upon receipt of the Commission's order in this docket.

[16] The PPA is being assigned to Avista Utilities "at cost" as testified to by Mr. Kalich. (Exh. CGK-4T, p. 2, ll. 11-13; also at p. 5, ll. 1-2)

that the Lancaster PPA would be transferred "at cost" and without any markup to Avista Utilities, subject to acceptable ratemaking treatment. (See also, Tr. pp. 810-11) Not only was it "at cost" (without any markup), but the evidence establishes that there was no lower market price available for a similar long-term capacity and energy contract or other resource available to Avista in 2007. (See discussion, below).

D. No Party Has Demonstrated that a Lesser-Cost Resource, Consistent With Avista's Needs At the Time, Was Available.

48 Both Avista and the Commission Staff believe that the Lancaster PPA was prudent and should be reflected in rates beginning in 2010. (See Buckley Testimony at Tr. p. 939) The only party challenging Lancaster is Public Counsel, and their only witness on the subject, Mr. Woodruff, when asked, could not identify any other CCCT that could have been acquired at a lower cost than Lancaster:

> Q. So you're not here to testify today that based on your familiarity in 2007 that you're aware of any green field or brown field site that Avista could have acquired that was less expensive than the Lancaster PPA?
>
> A. Yeah, I don't know what would or would not have been available to them as of that date.

(Tr. p. 933, ll. 1-8)

49 The evidence is undisputed that the Lancaster plant was acquired at a price substantially below other market transactions at the time, and since that time. The following table, excerpted from Mr. Storro's Exhibit RLS-6, at p. 10, shows the comparison made by Avista in April of 2007 to other similar combined-cycle combustion turbine plant transactions in the Northwest, and demonstrates that the Lancaster acquisition was at or below all other comparable transactions in the Northwest.

Table 1
Lancaster Levelized Cost vs. Other Regional CCCT Projects Plant Levelized Cost (2010-2026) $/MWh

Coyote Springs 2	78.37
Goldendale	97.72
Port Westward	92.80
Lancaster	79.37

50 Moreover, as further confirmation, the IRP's from other regional utilities, and the Northwest Power and Conservation Council, estimated the cost of new CCCT plants to be greatly above the price of the Lancaster contract, as demonstrated in Table 3, excerpted from Mr. Kalich's testimony. (See Exh. CGK-4T at p. 7)

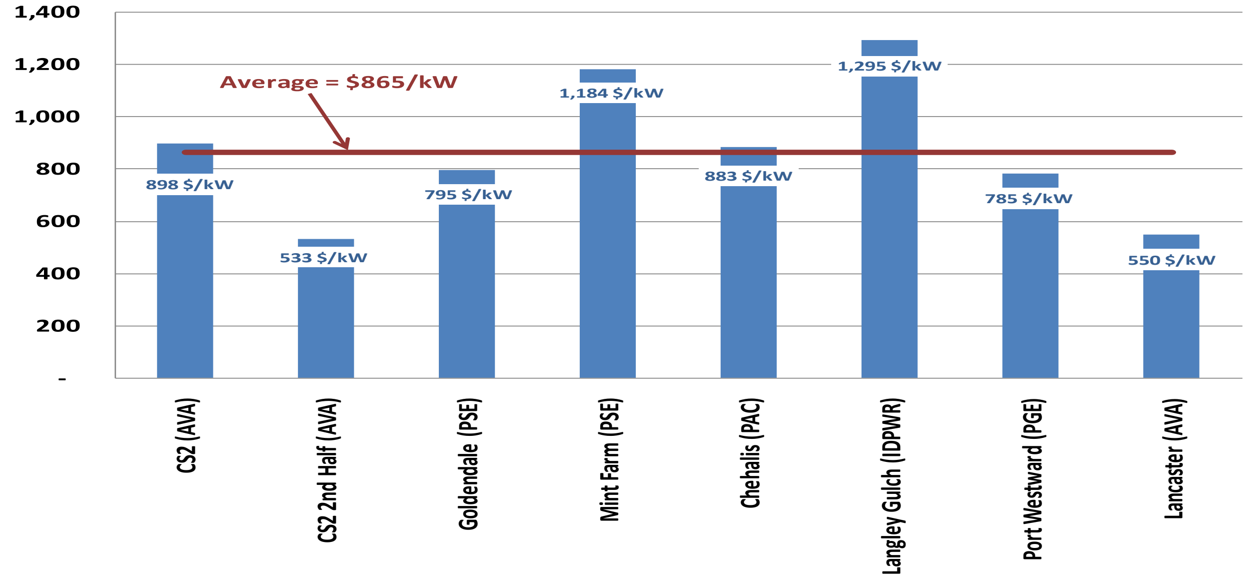
Table 3
Regional CCCT Projects Cost Assumptions

Source	**Year**	**Estimate**	**2010 Escalated ***
Avista	2007	786	859
Idaho Power	2006	693	780
Portland General Electric	2006	710	799
PacifiCorp	2006	814	916
Puget Sound Energy	2006	1050	1,182
Power Council	2000	525	706
Average			874

* estimate escalated at 3% per year from year of estimate to 2010

51 More to the point, while Avista had estimated in its 2007 IRP that a gas-fired generation project would cost $786 per kW for a plant installed in 2007 (or $859 per kW escalated to 2010), the Lancaster plant had an equivalent price of $550 per kW. (Id. at p. 7) Finally, taking a broader view, the Lancaster project is "one of the least expensive CCCT acquisitions ever made in the Pacific Northwest," as testified to by Mr. Kalich. Excerpted below is a chart of all regional CCCT project acquisitions from the year 2000 to present (expressed in 2010 dollars/kW).

Chart 1
Regional CCCT Projects Acquisitions
2000 to Present (2010 $/kW)



(Exh. CGK-4T, at p. 2)

52 Public Counsel, for its part, provided no evidence disputing (1) the need for a CCCT as the preferred resource option in the Company's 2007 and 2009 IRP's or (2) the fact that the Lancaster PPA represented the least cost resource to accomplish that end. Failing such, Public Counsel next turns its attention to a proposed disallowance of any recognition of Lancaster costs in 2010. The shortcomings of this position are discussed immediately below.

E. <u>The Lancaster PPA is a Long-Term Resource That Should Be Reflected in Rates Beginning January 1, 2010</u>.

53 As previously discussed, the record establishes that Avista Utilities had the opportunity to acquire the Lancaster PPA, <u>beginning in 2010</u>. There is no evidence in the record that the same PPA would have been available to Avista Utilities in 2011 or at some later date. This low-cost resource was set aside for Avista Utilities as part of the negotiations to sell Avista Energy, and as Mr. Norwood noted in response to questions from Commissioner Jones, Avista Corp recorded a loss of $4.3 million associated with the sale of Avista Energy. (Tr. p. 914)

54 That aside, the record would firmly support the Commission's decision to recognize the Lancaster PPA in rates beginning in 2010. As previously noted, the PPA will be used to meet Avista Utilities' energy needs in 3 out of 4 of the quarters of 2010 (excepting only the high run-off second quarter). (Exh. RLS-1T, p. 11, ll. 9-14) Moreover, the undisputed load and resource tabulations show that Avista would experience capacity deficits of 145 MW in 2011, with growing deficits into the future, as well as annual average energy deficiencies. (Id.) As testified to by Mr. Storro, on cross examination, Avista will use the Lancaster PPA to serve its requirements in 2010. (Tr. p. 769 and p. 846) To the extent that there is any surplus during that period, as always, Avista will look to sell the energy to third parties, and credit back any proceeds to ratepayers.

55 It is important for the Commission to understand that were it to disallow the Lancaster PPA in rates in 2010, Avista cannot simply re-market the capacity and energy associated with the contract for one year, and be made whole. The value of the contract lies with its duration (extending to 2026), and it would not be able to recoup, dollar-for-dollar, its costs through a one year, off-system sales transaction. As a consequence, Avista would only be able to offset a small portion of a $12 million shortfall in cost recovery associated with the PPA in 2010. Stated differently, to fully mitigate that impact, it would have to look to sell or reassign the entirety of the long term contract through 2026 to a third party, in order to be made whole. That is the essence of the matter: The true value to ratepayers of the Lancaster PPA cannot be measured by any one year – i.e., 2010 – but must be assessed over the length of the contract, where the real value lies. That was recognized in the Company's analysis, as well as in Staff Witness Buckley's testimony on the record, where he stated:

56 > . . . We look at the long-term nature of acquisitions, we don't concentrate on, you know, a first year effect as compared to some other alternative that may or may not have certain other issues built into it. There's no certainty that, you know, as

> compared to that other alternative that they're – it could have been built, there's no certainty that the alternative, let's say starting it in 2011, would have been available. Again, by taking the long-term approach in many cases there may be a short-term detriment effect in favor of the long term.

(Tr. p. 960, ll. 9-22)

57 Mr. Woodruff's statement, on behalf of Public Counsel, that Avista Utilities could simply go to the short term energy market to satisfy its 2010 needs, entirely misses the point, and reflects a fundamental misunderstanding of the value of acquiring a long term purchase contract. (See Exh. KDW-1T at p. 14) The Energy Crisis of 2000/2001 taught the market certain lessons: Namely, that one relies on short term energy contracts, purchased on the market, at their own peril; instead, where longer term purchase agreements can be negotiated at attractive prices, to provide for both the capacity and ongoing energy needs of the Company, that is the preferred option. Avista has an obligation to serve the capacity and energy needs of its customers. As such, it relies on long-term, firm capacity and energy resources such as Lancaster, to meet these obligations.

58 Moreover, even if we include 2010 in the market analysis, the Lancaster PPA still remains the least cost alternative to meet long-term capacity and energy needs. In response to Public Counsel Data Request 535 (see Exh. CGK-9-X) Avista explained how its analysis examined the net long-term benefit to ratepayers of acquiring the plant as early as 2010:

59 > . . . the methodology was to compare Lancaster to the cost of a plant constructed in 2011 to ensure customers were better off to purchase the plant in 2010 rather than waiting until 2011 to build a new facility. The 2007 IRP showed that procuring Lancaster in 2010 when it was made available would be 2.3% lower in cost, or $43 million, relative to a 2011 new CCCT plant that the company would otherwise construct. (Emphasis added.)

60 Therefore, over the life of the PPA (which is the appropriate perspective), ratepayers will be better off by $43 million by acquiring the PPA in 2010, as opposed to a new CCCT plant in

2011. Not only does the intuitive logic of acquiring a long-term PPA to meet ongoing capacity and energy needs makes sense, but that is supported by actual estimates of cost savings ($43 million) based on a 2010 "in-service" date. (Id.)

61 In the final analysis, however, it is difficult to "precisely time" resource acquisitions to perfectly coincide with expected load requirements. When rate basing prior coal plants (e.g., Colstrip) or, more recently, natural gas-fired turbine projects, there is always a certain "lumpiness" in resource acquisitions. This aspect of resource acquisitions is discussed in Avista's 2007 IRP, at p. 8-8. (See Exh. RLS-2) Resource acquisitions must be evaluated over their lifetimes, and not against a specific deficit year or set of conditions, especially when an opportunity arises to procure a resource such as Lancaster at a significant discount. (Kalich Rebuttal Testimony, Exh. CGK-4T, p.3, ll. 1-12)[17]

62 Mr. Woodruff, Public Counsel's lone witness on the subject of Lancaster, was not particularly well-versed in regional power supply matters. On cross-examination, he acknowledged that he had done little prior consulting work in the Pacific Northwest and had little or no prior experience in reviewing regional power projects, or the transmission or gas transportation grid. (Tr. pp. 927-933)

> Q. . . . So prior to February of 2009 [when he was engaged by Public Counsel], had you had any reason to familiarize yourself with available green field and a brown field projects specific to the Northwest?
>
> A. I think I was more familiar back in the 90's. If you look, you know, before February 2009 for the couple of years before that or the few years before that I didn't have a working knowledge of them. I would see the names in Trade Press because I would see them through [C]learing [U]p every week, but I –
>
> Q. Okay.

---

[17] As testified by Mr. Kalich, while this matter is still pending before the Commission, all parties, including Public Counsel, have supported PacifiCorp's acquisition of the Chehalis CCCT, several years prior to its need. (See Docket No. UE-090205). (Exh. CGK-4T, p. 3, ll. 6-12) According to Mr. Kalich's testimony, this plant cost PacifiCorp "50% more than Lancaster on an adjusted per kW basis." (Id.)

> A. So I recognize the names of virtually all of these projects, but I've not, you know, followed their status.
>
> Q. I believe you just testified for at least certainly the few years prior to this engagement prior to 2009 you hadn't had a reason to familiarize yourself with those projects?
>
> A. No particular client driven reason, no.

(Tr. p. 931, ll. 2-25)

63 Moreover, he admitted that he had not reviewed Avista's 2007 IRP "at all." (Tr. p.933, l. 19) Significantly, he admitted that he was not aware of any project that Avista could have acquired that was less expensive than the Lancaster PPA. (Tr. p. 933, ll. 1-14) Ultimately, even he acknowledged that ". . . the Commission may find the prices and terms of the Lancaster contracts appealing, and I understand that." (Tr. p. 1063, l. 24, p. 1064, l. 2)

64 Mr. Norwood, on behalf of the Company, very nicely summarized the position of the Company, as it relates to the possible absorption of nearly $12 million of Lancaster-related costs in 2010, were the PPA disallowed:

65 > . . . And so if we're to be in a circumstance where we would not recover that cost in 2010, we would absorb ($12 Million). As I mentioned earlier, no one has disputed that this agreement long term is a really great deal for our customers, and I believe it would be inequitable to ask the Company to absorb $12 Million in the first year and then pass on substantial benefits to customers in the remaining 15 or 16 years of the agreement. You know, we had the opportunity to set this aside for customers, and again, as I mentioned before, we have the option or the opportunity to have this in rates or we would have to build another plant comparable, which would be approximately priced [twice] the cost.

(Emphasis added) (Tr. p. 1079, l. 18, p. 1080, l. 6)[18]

[18] Mr. Norwood also rebutted Mr. Woodruff's assertions regarding the use of combined cycle turbines to balance new wind resources, noting that Lancaster, like Coyote Springs 2, has the ability "to flex, so to speak, to integrate wind" and that ". . . it's really more efficient to use the flexibility in the combined cycle to integrate wind, and that would be our plan going forward, that together with our flexibility in our hydro system." (Tr. pp. 1078-1079)

F. <u>Testimony of Staff Witness Buckley Further Attests to Prudence in Light of Other Qualitative Factors, As Well</u>.

66 Staff Witness Buckley provided testimony supporting the prudence of the Lancaster PPA acquisition, beginning in 2010. He reiterated the value of an attractively-priced long term power purchase agreement, especially in volatile markets. His perspective was much broader than a select examination of the precise energy or capacity needs in any one year, such as 2010. Mr. Buckley testified that, "I would hate to see them not make transactions that are at least beneficial in the long term because there are some short-term problems or some issues . . . [concerning whether] this can be delayed a year . . . ." (Tr. p. 963, ll. 307) Instead, he saw value in not only the pricing terms of the PPA, but also in other qualitative aspects as well. (<u>See</u> Tr. pp. 952-957) He described the value of acquiring a long-term resource (through a PPA) located in the utility's own backyard (i.e., Rathdrum, Idaho) that is immediately adjacent to its own transmission system (Tr. p. 953) and its availability to provide reserves for wind. (Tr. p. 973) He also recognized the impossibility of precisely timing resources to meet precise load conditions. (Tr. pp. 966-967) In Avista's words (not Mr. Buckley's), he generally testified to the value of "having iron in our own backyard."

67 Staff's support for the PPA, beginning in 2010, was unwavering, during the course of Mr. Buckley's cross-examination. He did review extensive discovery surrounding the issue and has reached an informed judgment, which brings many years of experience to bear. His breadth of experience, and particularized knowledge of the Pacific Northwest, compares favorably with that of Mr. Woodruff.

G. <u>BPA Transmission Contracts and Gas Transportation Contracts Are Integral to the Project</u>.

68 Public Counsel also raises concerns regarding the amount of transmission capacity and natural gas transportation capacity necessary to serve the Lancaster Plant. The rebuttal testimony

of Company Witness Lafferty squarely addresses these concerns, and he makes the point that both the transmission and transportation contracts are an integral part of the project. (Exh. RJL-1T)

69 Beginning with Lancaster transmission, the acquisition of the PPA includes the assignment of 250 MW of BPA firm point-to-point transmission from the Lancaster plant to the John Day interconnection point on the Bonneville system. (Id. at p. 2, ll. 8-10)[19] Avista will use this transmission to move power to Avista's system to serve retail loads, or to other points when the power is sold on the wholesale market. The transmission will be purchased at BPA's tariffed rate, which is reasonable and "in line" with other transmission providers in the region.[20] The significant point is emphasized by Mr. Lafferty – namely, that "the plant's generation capability, including the duct burner, exceeds the amount of BPA firm transmission in all months." (Id. at p. 3, ll. 1-3) (The Company will otherwise purchase additional non-firm transmission for the remaining balance of the generation.) (Id.)[21]

70 BPA's transmission system is the only interconnection, at present, with the Lancaster plant. Nevertheless, as explained by Mr. Lafferty, Avista is exploring other alternatives, in the longer term, to the continued use of BPA transmission. To that end, it is in the process of conducting joint studies with BPA to examine interconnecting Avista's transmission directly to the BPA Lancaster substation, where the Lancaster plant is currently interconnected. This will, however, take a "minimum of two more years," in order to conduct the necessary power flow and reliability studies and to design and construct the facilities. (Exh. RJL-1T, p. 4) Mr. Woodruff's

19 There are two BPA transmission agreements, one for 150 MW and one for 100 MW, that both terminate June 30, 2026. The 150 MW agreement can be terminated by Avista with two years' notice. The 100 MW contract cannot be terminated early. (Exh. RJL-1T, p. 2, ll. 8-12).

20 According to Mr. Lafferty's testimony, BPA's point-to-point transmission rate is $1.501/kW-month, which is reasonably close to Avista's point-to-point transmission rate of $1.40/kW-month. (Exh. RJL-1T, p. 2).

21 Mr. Lafferty's Table 1 appearing at page 3 of his rebuttal testimony tabulates the transmission capacity as compared with the generation capability through every month of the year and demonstrates that Lancaster's capability will exceed the available firm transmission in each month. (Id.)

assumption that the BPA transmission contract may be "entirely unnecessary," or that the Company can somehow re-market the majority of the BPA transmission associated with the Lancaster plant in 2010 is utterly misplaced. (See Exh. KDW-1T, p. 29, ll. 16-19; p. 30, ll. 17-19) As explained by Company Witness Kalich, until Avista can directly interconnect with Lancaster, it will be necessary to continue to use BPA transmission for the next few years. Thereafter, Avista has assumed that it can re-market three-fourths of this transmission capacity based on the long term operation of the plant over 17 years, not just for calendar year 2010, as otherwise assumed by Mr. Woodruff. (See Exh. CGK-4T, p. 15, ll. 16-19)

71 Likewise, the Lancaster gas transportation contracts are essential to the operation of the plant. Gas supply for Lancaster originates from two delivery points: delivery capability from Alberta is 25,966 Dth/day and 26,388 Dth/day from Malin, for a total delivery capability of 52,354 Dth/day. (Exh. RJL-1T, p. 4, l. 17 – p. 5, l. 9) As explained by Company Witness Lafferty, under average temperature conditions, Lancaster will consume approximately 48,000 Dth/day. However, at times of peak generation conditions, Lancaster is estimated to consume approximately 51,400 Dth/day, which is only slightly lower than the total delivery capability under the gas contracts of 52,354 Dth/day. (Id.)

72 Mr. Lafferty explains why Avista does not have excess gas transport capability for its combined-cycle combustion turbine plants. When both Lancaster and Avista's Coyote Springs 2 are operating at full capacity, "Avista will not have enough long-term firm gas transportation capacity and will have to purchase additional capacity," as testified to by Mr. Lafferty. (Id. at p. 6, ll. 1-3) This is demonstrated in Table 3 excerpted from Mr. Lafferty's rebuttal testimony (Exh. RJL-1T, p.6):

Table 3
Lancaster & CS2 Gas Consumption and Transportation

Month	Lancaster Gas Consumption w/ Duct Burner	CS2 Gas Consumption w/ Duct Burner	Lancaster Gas Transport	CS2 Gas Transport	Difference
	(dth/day)	(dth/day)	(dth/day)	(dth/day)	(dth/day)
Jan	49,778	50,739	50,742	43,000	(6,775)
Feb	49,256	50,272	50,742	43,000	(5,786)
Mar	48,775	49,634	50,742	43,000	(4,667)
Apr	48,169	49,007	50,742	43,000	(3,434)
May	47,347	48,276	50,742	43,000	(1,881)
Jun	46,638	47,626	50,742	43,000	(522)
Jul	45,961	46,963	50,742	43,000	818
Aug	46,110	47,151	50,742	43,000	481
Sep	46,920	47,994	50,742	43,000	(1,172)
Oct	48,044	49,030	50,742	43,000	(3,332)
Nov	49,098	50,017	50,742	43,000	(5,373)
Dec	49,606	50,525	50,742	43,000	(6,389)
Average	47,975	48,936	50,742	43,000	(3,169)
Peak Day (1)	51,397	51,647	50,742	43,000	(9,302)

1) Based on 0 degrees Fahrenheit for Lancaster and actual for CS2

73 Mr. Woodruff, on behalf of Public Counsel, picks up on an erroneous assumption otherwise contained within the Thorndike Landing evaluation, which only assumed an average consumption rate of 43,000 Dth/day (vs. 51,397 Dth/day at "peak"). The one area in which the Company has expressed disagreement with the Thorndike study was with reference to this assumption regarding gas transportation capacity, inasmuch as Thorndike (and Mr. Woodruff) both fail to incorporate the operation of the Lancaster "duct burner" which requires the full utilization of all gas transportation capability. (Exh. RJL-1T, p. 6) When the Lancaster duct burner is in operation, and when combined with the Coyote Springs plant, under full operating

capacity, Avista will not have enough long term firm gas transportation capacity, even with the transportation contracts in question. (Id.)[22]

H. The Lancaster PPA Does Not Represent a "Commodity Transaction" as Defined in the Prior ERM Settlement Stipulation.

74 Public Counsel argues that the acquisition of the Lancaster PPA specifically runs afoul of the provisions of the settlement stipulation establishing the Company's Energy Recovery Mechanism (ERM). (See Exh. KDW-1T, p. 11, ll. 17-21) This is decidedly not the case. Mr. Kalich quotes the applicable language in his rebuttal testimony from the settlement stipulation in Docket No. UE-011595, which states in part:

75 > The Company agrees that it will not enter into electric or natural gas commodity transactions with Avista Energy relating to Avista Utilities' electric operations until the Energy Cost Deferral Balance carries a net credit balance. This provision does not preclude transactions between the two companies related to Avista Utilities' natural gas distribution business. (Emphasis added).

76 As explained by Mr. Kalich, this language addresses electric and natural gas "commodity transactions" with Avista Energy, but does not apply to a "tolling" arrangement such as this. Mr. Storro described the essence of the "tolling" arrangement in his direct testimony. (Exh. RLS-1T, p. 10, ll. 4-9) In his words:

77 > In exchange for payments outlined in the PPA, the Utility will have the right to dispatch Lancaster. This requires the Company to arrange and pay for natural gas fuel procurement and transportation to the Lancaster plant, as well as subsequent transmission to move the power from the plant. In turn, the Company is entitled to the entire electric capacity and energy output from the plant.

78 Simply put, under the typical "tolling arrangement," the utility essentially "rents the plant," having the right to dispatch Lancaster according to its own needs. Avista Utilities, not the project owner, will arrange and pay for all natural gas fuel (commodity) procurement and

[22] Indeed, the "duct burner" was used in 19 out of the 20 month period (January 2008-August 2009) for CS2, and, as testified to by Mr. Lafferty, "the duct for burner operation at Lancaster is expected to be similar to that of CS2." (Exh. RJL-1T, p.7)

transportation to the plant as well as electric power (commodity) away from the plant. As such, it is entitled to the plant's output. Avista receives no commodity associated with the payment to "rent" the Lancaster plant. Avista will only receive electric commodity when it purchases natural gas commodity from the market-place, and then uses the plant to convert it to electric commodity.

79 Mr. Buckley, on behalf of Staff, was even more emphatic in his rejection of any argument that the PPA represented a "commodity transaction" in violation of the prior ERM settlement:

> Q. Do you believe that that section of the settlement stipulation [ERM] is applicable to the Lancaster transaction?
>
> A. <u>No, I do not</u>. I was part of that settlement, and although we always have to admit that people have different view points even on settlement, that was meant more to address the concerns at the time of making hourly, more secondary market purchases, hourly market purchases, from Avista Energy to the Company, not what <u>I would characterize this as</u>, is essentially <u>a acquisition, if nothing else, in the full operating rights of a large power plant. To me they're two separate, not even close.</u>

(Emphasis added) (Tr. p. 942, ll. 7-19)[23]

80 Accordingly, no other party to the prior ERM stipulation, <u>except for</u> Public Counsel, has raised concerns that the Lancaster PPA would somehow violate the language of the stipulation. That is presumably because the other parties appropriately recognize that the "tolling arrangement" is essentially the right to operate a gas-fired generation plant, as opposed to a simple purchase of a commodity on the market.

I. <u>Application of RCW 80.80.040 Regarding A Commission Determination of Greenhouse Gas Emissions</u>.

81 During the evidentiary hearings, the Bench raised the question of whether the provisions of RCW 80.80.040 would apply to the Lancaster PPA, insofar as it pertains to "greenhouse gas emission performance standards." RCW 80.80.040 requires that greenhouse gas emission

[23] Mr. Buckley further explained that the purpose of the ERM settlement stipulation, with regard to "commodity transactions" was really to prevent ". . . the two companies really to be interacting together on something on a day-to-day basis like that." (Tr. p. 943, ll. 16-17).

performance standards be below 1,100 pounds of greenhouse gases per MW hour, with respect to all base load electric generation for which electric utilities enter into "long-term financial commitments" after July 1, 2008. In its response to Bench Request No. 12 (Exh. B-13), Avista stated its belief that the provisions of RCW 80.80.040 and WAC 480-100-405 do apply to the Lancaster PPA, and requested a determination <u>in this proceeding</u> that the Lancaster PPA complies with the requirements of the aforementioned laws and regulations. To that end, Avista's response to Bench Request No. 12 drew from evidence already of record, and demonstrated that the greenhouse gas emissions related to the Lancaster PPA are <u>810 pounds</u> of CO_2 per MWh, and as such, are <u>well below</u> the emission limit. The response to the Bench Request specifically details how this was calculated and where, in the record, the sources for this calculation could be located.[24]

[24] Avista also provided all of the information otherwise required in WAC 480-100-405 and WAC 480-100-415 with respect to this issue. (<u>See</u> Avista's Response to Bench Request No. 13) (Exh. B-14) Accordingly, the necessary information is before the Commission which shows that the Lancaster PPA satisfies the requirements of RCW 80.830.040 and WAC 480-100.

The Commission Staff, however, in its response to Bench Request No. 12 (<u>see</u> Exh. B-16) questions the application of the greenhouse gas provisions to the Lancaster PPA, given their reading of whether a "long-term financial commitment" with respect to the PPA occurred prior to or after July 1, 2008. Avista filed a Supplemental Response to its original Response to Bench Request No. 12, in which it replied to Staff. (<u>See</u> Exhibit B-13) Therein, Avista noted that it is important for the Commission to make the determination of compliance with the greenhouse gas emission performance standard <u>at this time and as part of its final deliberations in this docket</u>. It again noted that the Lancaster PPA easily satisfies the threshold emission standard, all of which can be verified based on evidence already in the record. This determination, at this time, would "moot" any issue as to <u>when</u> the Utility, itself, entered into a "long-term financial commitment," for purposes of the statute. It would not be the most efficient use of Commission resources to require Avista to <u>subsequently</u> make a separate application for a determination of compliance under WAC 480-100-415, <u>after</u> any order in this rate case approving the Lancaster PPA in December of 2009, and have that application acted upon by the Commission <u>prior to</u> the January 1, 2010 effective date of any Lancaster PPA transfer to the utility. Indeed, it may not even be possible for the Commission to act this quickly with respect to any such application.

Therefore, the Company continues to urge the Commission to take the more sensible approach and to take this matter up now in the context of the pending rate case, rather than await a separate application from Avista after the conclusion of the rate case and prior to January 1, 2010. The Commission has before it the information to make the determination of compliance at this time.

III. OTHER CONTESTED ADJUSTMENTS TO REVENUE REQUIREMENT.

A. Guiding Principles for Pro Forma Adjustments.

82 Chairman Goltz requested further elaboration on the guiding principles that should inform the Commission's judgment with respect to pro forma adjustments. (See Tr. p. 1288) Company Witness Norwood, in his rebuttal testimony, discussed at length the principles that should guide the Commission's deliberations in this regard. (Exh. KON-1T) He summarized them as follows:

> 1. The pro forma adjustment should be "known and measurable,"
>
> 2. The adjustment should take into account any "offsetting factors," and
>
> 3. The adjustment should preserve the relationship of changes in revenues, expenses and rate base during the ratemaking period, which we refer to as the "matching principle."

(Id. at p. 5, ll. 3-10) He then elaborated on each of these principles and discussed how the Commission has applied them in past decision-making.

1. In Order To Be "Known And Measurable," There Should Be A Reasonable Expectation That The Capital Or Expense Item Will Be Used And Useful During The Rate Period And That The Costs Are Prudent.

83 At the outset, the Commission should reject any suggestion that pro forma adjustments must be known with "certainty" in order to pass the "known and measurable test." This would belie accepted ratemaking practice in the past and ultimately would prevent the parties from properly "matching" revenues, expense and rate base for rate making purposes. In fact, Staff Witness Kermode, in connection with his recommended approval of Avista's pro forma adjustment related to the Noxon Unit No. 3 hydroelectric project upgrade (to be completed in 2010), perhaps said it best:

84 [T]he Commission has allowed inclusion in rate base of plant that will be used and useful during the rate year. There must be a reasonable expectation that the plant will be complete and the costs are prudent. (Emphasis added).

(Exh. DPK-1T, p. 40) The history and practice of the Commission is replete with examples of the use of "reasonable estimates" for purposes of ratemaking. As noted by Mr. Norwood, there are "numerous pro forma adjustments that are routinely included in general rate cases that have been consistently supported by the Commission Staff, and other parties, and had been approved by the Commission that do not involve certainty of the prices or volumes, and do not involve historical test year values." (Emphasis added) (Exh. KON-1T, p. 8, ll. 8-12) He cited as a prominent example, power supply costs for ratemaking purposes that often include pro forma adjustments based on, e.g., a three-month average of future natural gas prices for the future rate year for thermal generation. Of course, these wholesale market gas prices are not known with certainty, but are the best estimate of costs that the company expects to incur during the rate period. Similarly, the volume of natural gas to be purchased for generation in the rate year is based on modeled estimates of thermal generation using estimated loads, estimated hydroelectric conditions, estimated availability factors for the thermal plants, and other estimates of wholesale market conditions. (Id. at p. 8, ll. 15-23)[25]

85 Finally, perhaps the best example of a pro forma adjustment to rate base in this case is the Noxon Rapids hydroelectric plant unit No. 3 upgrade, previously referenced. This upgrade is not expected to be completed until April of 2010, but has been pro formed into this case and has not been opposed by any party. This pro forma adjustment for 2010 is based on an estimated investment cost, and an estimated in-service date. (Id. at p. 10, ll. 5-19) As noted above, Staff Witness Kermode acknowledges that the Commission allows post-test year rate base additions

[25] Other examples occur outside of the context of power supply. For instance, the pro forma expense for "injuries and damages" has been based on a 6-year rolling average of actual payments for injuries and damages not covered by insurance, instead of a test year amount. Also, a 5-year average for OASIS wheeling revenues is used, given the variability of these revenues from year-to-year.

that will be in service during the rate year and will be "used and useful" in order to provide service to customers "during the rate year." (Exh. DPK-1T, p. 39, ll. 23-29)[26]

86 In the final analysis, Mr. Norwood concisely made the point that "ratemaking is not an exact science; reasonable assumptions need to be made to assure that the Company will have a reasonable opportunity to recover its prudently incurred costs." (Exh. KON-1T, p. 9, ll. 6-7) In this Commission's Sixth Supplemental Order in Docket No. UW-010877, dated July 12, 2002, the Commission, itself, enunciated the following principle with regard to adjustments to the historical test year, noting that adjustments will be made:

> 87 . . . For known and measurable events that will occur prospectively (pro forma adjustments), to best estimate the relationship between the Company's costs and revenues and thus establish rates that are fair, just and reasonable and allow the Company the opportunity to earn a fair rate of return. (Emphasis added).

(Order at p. 7, ¶29) If "reasonable estimates" are not allowed for ratemaking, the Company will not have been given a reasonable opportunity to recover its costs of providing service during the period that the new rates will be in effect. It will not have the reasonable opportunity to earn a fair rate of return.[27]

2. The Pro Forma Adjustment Should Take Into Account Reasonable Estimates Of "Offsetting Factors," Based On The Informed Judgment Of The Parties.

88 To begin with, one should not assume that every investment a utility makes necessarily translates into increased efficiencies, revenues, or reduced costs. Staff Witness Parvinen suggests this to be the case, when he asserts that "there is inherently a return on such investment

---

[26] Previous examples of pro forma adjustments in recent cases related to Avista's transmission upgrades, and adjustments related to other generating projects, including recent upgrades to Colstrip, all involved estimated costs and estimated in-service dates. (Exh. KON-1T, p. 11, ll. 1-3)

[27] Elsewhere in his testimony, Company Witness Norwood described the planning and management process used to develop and plan capital additions, noting how "robust" the process is, involving many different departments and close scrutiny of project timetables and costs. (Exh. KON-1T, pp. 11-12). He then makes the point that actual capital expenditures for the utility compared to planned expenditures in recent years have tracked very closely – i.e., during the last two years actual expenditures have been 98% of planned expenditures. (Id.) He concludes that this should provide some reassurance to the Commission that the overall levels of planned expenditures, for at least 2009 (which the Company has pro formed into this case), will occur and should be included for recovery in retail rates. (Id. at p. 12, ll. 9-24)

immediately upon its being placed into service." (Exh. MAP, p.8, ll. 12-15) An obvious example suggesting otherwise, is the investment Avista must make to accommodate changes to transportation corridors, by relocating its facilities – none of which gives rise to additional revenues or a reduction in expenses associated with the investment. (Exh. KON-1T, p. 6, ll. 16-21) The testimony of Company Witnesses Kinney (Exh. SJK-1T) and DeFelice (DBD-4T) describe other proposed rate base additions where there are no savings due to reduced costs or increased revenues. It should be remembered that (1) the Company <u>begins by removing</u> all revenue-producing plant additions, as part of its pro forma adjustment; (2) the historical test period, itself, already reflects any built-in savings or efficiencies; and (3) to the extent that there are any remaining efficiencies or cost savings resulting from the investment, those may not occur for many years beyond the next-effective rate year.

89 As will be discussed below, Staff has only proposed to include generation and transmission plant through June of 2009, and only to the extent that such plant was placed into service for reliability concerns or otherwise due to compliance purposes. Therefore, these plant additions do not, by their nature, give rise to cost savings or efficiencies, nor has Staff identified any potential "offsets" in that regard. (In it's <u>alternative</u> proposal, the Company has taken the same subset of generation and transmission plant investments and pro formed them only to the end of 2009 – not even into the effective rate year of 2010.)

90 The pro forma adjustments in this case with respect to plant additions, nicely illustrate the fact that pro forma plant investment does not necessarily give rise to "offsetting factors" (i.e., savings or efficiencies). Beyond the example of required "road moves" due to relocations of facilities required by local governments, Company Witness Kinney testifies that the North American Electric Reliability Corporation (NERC) requires sufficient redundancy in Avista's transmission and substation equipment, in order to prevent a simultaneous outage on two different facilities that would prevent the Company from continuing to serve customer's loads, and prevent disruption on neighboring systems. This has required Avista to spend substantial additional capital dollars to create and sustain this redundancy – none of which provides offsetting revenues or a reduction of expenses; it is simply an additional cost of meeting a federal requirement. (Exh. KON-1T, p. 14, ll. 3-12) Other examples are set forth in Company Witness Kinney and DeFelice's rebuttal testimony.[28] (Exhs. SJK-4T and DBD-4T)

91 Finally, as previously noted, Avista began by excluding any rate base additions that would have offsetting revenues or expenses. For example, the Company excluded any new distribution investment dedicated to serve new customers. (Id. at p. 17, ll. 17-22)[29] And, it is well to remember that most of the rate base additions pro formed into this case are related to the reliability of the electrical system and/or the replacement of aging equipment which "generally have no offsets in the form of increased revenues, reduced expenses or other factors," as testified by Mr. Norwood. (Id. at p. 18, ll. 1-5) Rather, any benefit in the future would not be a reduction to existing costs, but instead would be an avoidance of increases in current expense levels that would otherwise occur if the investment were not made. (Id.)

3. The Pro Forma Adjustment Should Preserve The Relationship Of Changes In Revenues, Expenses And Rate Base For The Ratemaking Period Through A Proper "Matching," And Thereby Provide The Company With A Reasonable Opportunity To Earn Its Authorized Return.

92 In Avista's instant filing, in order for the rates during the 2010 rate year to be "fair, just and reasonable" it is essential that all known and measurable rate base additions that do not

[28] Mr. Norwood also explains why one shouldn't assume that there are Operation and Maintenance (O&M) savings associated with the replacement of aging equipment with new equipment. (Exh. KNO-1T, p. 16, l. 12, p. 17, l. 15) He notes that on a net basis, the Company will continue "to experience O&M costs to maintain a system that continues to age." (Id.) He notes that "the reinvestment and upgrades actually serve, to a large extent, to allow the Company to avoid additional costs in the future associated with maintenance – not to reduce the overall level of existing O&M costs." (Id. at p. 16, l. 24, p. 17, l. 2)

[29] Revenue from the new customers would offset the investment to hook them up; therefore, Avista excluded that new investment from the pro forma rate base additions in this case. (Exh. KON-1T, p. 17, ll. 20-22).

otherwise have material "offsets" be included through the pro forma adjustments. Failing this, the Company will not be given a reasonable opportunity to earn its authorized rate of return.[30]

93 In fact, the Company, itself, essentially violated the "matching" principle when it filed the case by understating its overall revenue requirement by excluding 2010 capital additions (with one exception relating to the Noxon upgrades). As noted by Company Witness Norwood, "if we were to reflect our true cost to serve customers during the rate year, we would pro form rate base additions through 2010, on an average of monthly average (AMA) basis, and then discount that rate base back to the test year using the production property adjustment." (Exh. KON-1T, p. 18, ll. 16-19) Instead, the Company simply pro formed non-revenue producing capital, otherwise required for reliability purposes, through the end of 2009 only. If anything, this represents a very conservative portrayal of the Company's need for rate relief during the 2010 rate year, when substantial additional capital will be spent on projects that are used and useful to provide service.

94 Accordingly, a "mismatch" has already occurred in the customers' favor. Customers' rates in 2010 will not include the costs associated with new plant additions in 2010 that will be used to meet their energy needs and Avista will continue to experience "regulatory lag related to capital expenditures." (Exh. KON-1T, p. 23, ll. 16-19)[31] Lastly, it should be recognized that the environment in which the utility operates today, given increased spending mandates for reliability purposes, is much different than the past. As noted by Mr. Norwood:

---

[30] Again, the language of this Commission from its Sixth Supplemental Order in Docket No. UW-010877 (July 12, 2002) is worth repeating as a fair summary of the "matching" principle. There, the Commission stated, with regard to adjustments to the historical test period, that adjustments will be made:

> . . . For known and measurable events that will occur prospectively (pro forma adjustments), to best estimate the relationship between the Company's costs and revenues and thus establish rates that are fair, just, and reasonable and allow the Company the opportunity to earn a fair rate of return. (Emphasis added).

(Order at p. 7, ¶29)

[31] Even if Avista were to file a new general rate case in early 2010, an 11-month procedural schedule would cause new rates from that case to become effective no earlier than the end of 2010, or early 2011. (Exh. KON-1T, p. 23, fn. 4).

95

> Today our annual utility capital investment is much higher than annual depreciation expense, due to, among other things, the much higher cost of materials, mandatory reliability requirements and aging infrastructure which must be replaced or upgraded. The increased capital requirements are spread across the entire spectrum of generation, transmission, and distribution. This will naturally result in more pro forma rate base adjustments to properly reflect in retail rates the cost to serve customers.

(KON-1T, p. 25, ll. 9-14) This is unlike the level of annual expenditures previously spent by the Company on new utility plant that generally approximated the level of annual depreciation expense. (Id. at p. 25, ll. 4-6) Simply put, the Company is in a different "cost environment," and not one of its own choosing. It must satisfy government mandates, as well as its overall "obligation to serve" customers with safe and reliable service.

B. The Commission Should Recognize Avista's Proposed 2009 Capital Additions.

96 As shown in the summary of revenue requirement adjustments appearing as Appendix B to this Brief, Avista and the Staff have pro formed differing levels of capital additions into rates. For its part, the Company began with a rate base for the historical test year, consisting of the average-of-monthly averages for the 12 months ended September 30, 2008. Adjustments were then made to reflect new additions, accumulated depreciation and deferred income taxes through December 2009. As such, the proposed rate base reflects net plant-in-service that will be used to serve customers as of the end of 2009. With the exception of the investment in the Noxon facility upgrade (discussed below), the Company has pro formed in no additional plant for the 2010 rate year.[32]

97 Staff, on the other hand, has proposed to include generation and transmission capital projects that met certain criteria determined by Staff, including projects required by laws, regulations or directives from regulatory bodies, as well as projects related to reliability. As

[32] This pro forma rate base was then discounted back to the test year ended September 2008 using the production property adjustment to ensure a proper matching of revenues, expenses and rate base for test-year ratemaking.

explained by Company Witness DeFelice, for this subset of plant additions, Staff only included projects completed during the October 1, 2008 (end of test period) through June 30, 2009 timeframe. (Exh. DBD-4T, p. 4, ll. 1-9) (Exh. DBD-5 contains a detailed listing of projects included by Staff). It should be noted, however, that in doing so, Staff has excluded the Company's investment in this subset of projects during the second half of the year, thereby excluding the majority of Avista's 2009 capital. (Id. at p. 5, ll. 10-14) Indeed, as tabulated by Company Witness Storro, of the $21.4 million of generation-related projects slated for completion in 2009, $16.5 million of that investment will occur during the second half of 2009, while only approximately $5 million represents investment in projects completed through June 30, 2009 (and otherwise accepted by Staff). (Exh. RLS-7T, p. 3) The bulk of capital expenditures for generation plant typically occurs during the second half of the year, given the scheduling of generation plant maintenance and construction, as well as weather-related construction windows.[33]

98 Accordingly, Staff's proposal to only pro form in the first half of 2009 capital investment, ignores the vast majority of capital expenditures that relate to projects that will be in-service, and used and useful by December 31, 2009. As noted above, the only 2010 capital addition – i.e., during the rate effective period – relates to the Noxon Unit No. 3 generating facility upgrade.

99 For its part, Public Counsel rejected the Company's proposal to include capital additions through December of 2009, with the exception of generation plant, arguing that the Company's proposal for non-generation assets did not reflect any corresponding increase in revenues. (See Testimony of Witness Larkin, Exh. HL-1T, p. 14, ll. 7-16) As explained by Company Witness

[33] Similarly, and by way of further example, Company Witness Kinney (Exh. SJK-4T, p. 3) tabulates the $21.8 million (system) of transmission and electric distribution projects that will be completed in 2009, noting that $16.8 million relate to projects completed in the second half of 2009, with approximately $5 million of a total being completed during the first half of the year. Again, this makes the point that, for many of the same reasons relating to construction windows, much of the investment in new plant does not occur until the second half of any calendar year, with the year 2009 being no exception.

DeFelice, however, the Company's adjustment to capital additions in 2008 and 2009 did, in fact, exclude all capital that was for customer growth or new revenue. (Exh. DBD-4T, p.7, l.17, p. 8, l.8)[34]

100 Even with reference to Public Counsel's proposal to include generation assets, there were multiple errors, explained by Company Witness DeFelice. (Id. at p.8, l.9, p.9, l.19) Mr. DeFelice explained that by only using the net additions to determine the adjustment for cost, but using the depreciation expense on all assets for accumulated depreciation, Public Counsel created a "serious mismatch" by using this method to determine the rate base change during this period of time [2008]. Moreover, for the 2009 period (January 1, 2009 through June 30, 2009), Public Counsel Witness Larkin made the same mistake by using only the additions for the costs, but using depreciation expense on all assets, not just the current period plant additions, in order to compute the change to accumulated depreciation. (Id.) As such, his calculation produces an "apples to oranges" comparison. (Id.)

101 With respect to natural gas capital, Staff recommended the rejection of the Company's proposal to include in rate base the net plant that will be added through December of 2009. As such, Staff removed $7.3 million from the Company's proposed natural gas rate base, which served to reduce the Company's natural gas revenue requirement by $1,442,000. (Exh. DBD-4T, p. 5, ll. 10-19) Company Witness Howell, however, in his rebuttal testimony explained why these natural gas capital additions are in fact known and measurable, with minimal or no offsetting factors. (See Exh. JP-3T) Again, it should be remembered that only non-revenue

[34] The Company has spent, on average, over the past 4 years approximately $16.4 million per year in Washington for the hookup of new electric customers and approximately $8.9 million for the hookup of new natural gas customers. By excluding the costs associated with this capital from the Company's case, the "new revenue" that will be generated from new customers was properly excluded, to provide a proper matching of revenues and costs. In this way, the Company purposefully excluded this new revenue-producing capital so a proper matching would occur, since the new revenue was also excluded. (Exh. DBD-4T, p. 7, l. 17 – p. 8, l. 3).

producing capital has been added to the pro forma gas rate base, as was also true with regard to the electric rate base.[35]

102 While the Company continues to believe that its original proposal to include the 2009 capital additions remains correct, it did propose an alternative approach for the Commission's consideration, simply building on to Staff's proposal regarding capital additions. To begin with, the rate base at September 30, 2008 (end of test period) was not adjusted, leaving this rate base stated on an AMA basis for the test year, as proposed by Staff.[36] Next, Avista used the same subset of generation and transmission assets utilized by Staff, but included capital expenditures for this subset of assets through the end of 2009. It is important to note that Avista, through its original filing and through discovery, has provided support for all of these projects that will be completed in 2009, and accordingly, the information has been made available for audit purposes. The testimony of Mr. Storro and Mr. Kinney, on behalf of the Company, demonstrates that all of these projects will be completed and in service by the end of 2009. (Exh. SJK-4T and Exh. RLS-7T). No party has presented evidence challenging the fact that these projects will be completed and in service as of the end of the year.

103 Finally, Avista identified 6 electric distribution projects, 4 natural gas projects, and 3 general plant projects that were completed and placed into service by July 31, 2009. These projects are the subject of testimony by Avista Witnesses DeFelice (Exh. DBD-10, pp. 17-18 regarding a natural gas distribution project and the three general plant projects), Heather Cummins (Exh. HLC-1T, regarding 6 electric distribution projects), and Mr. David Howell (Exh.

---

[35] Public Counsel, like Staff, recommends rejection of the Company's proposal to include net plant that will be used and useful during 2008 and 2009 and, for the reasons explained above, such proposal will severely understate the capital investment that will actually be used to serve customers during the 2010 rate year. (Exh. DBD-4T, p. 11, ll. 5-13).

[36] Historically, Avista has annualized major plant additions during the test year (adjusted these assets to an end-of-period basis) which Staff has agreed to in previous cases. While Avista believes this is the proper treatment, Avista has not included this adjustment in this alternative analysis. (Exh. DBD-4T, p. 12, ll. 17-21).

DRH-1T, regarding the remaining natural gas distribution capital projects). Again, as with the generation and transmission projects, no party to this proceeding has disputed whether these distribution projects were completed and in service as of July 31, 2009 or otherwise challenged the prudency of any expenditures relating thereto. Moreover, on cross examination, Mr. Kermode acknowledged that these projects were, essentially "bought and paid for":

> Q. And those because they reflect investment only through 7/31/2009, those are completed, invoiced, billed, paid for, correct?
>
> A. In that they're completed and based on my prior review of the records, I believe that would be a correct statement.

(Tr. p. 728, ll. 8-13)

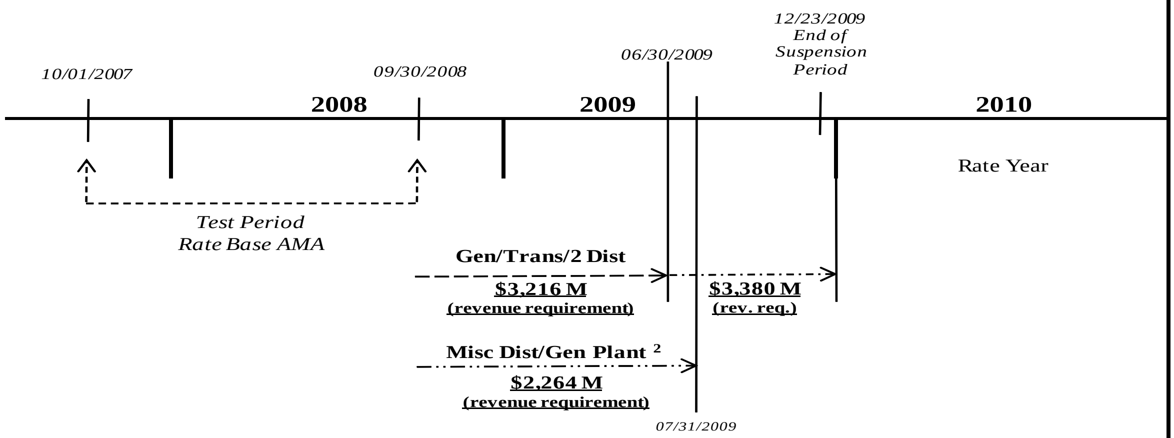
104 Finally, as part of the process of arriving at an "alternative" approach, Avista again challenged each of its witnesses to identify any possible "offsets" in the form of cost savings or additional revenues. On a project-by-project basis, each of the above-mentioned Avista witnesses sought to identify any conceivable "offset" that might be incorporated, in order to present the most conservative approach possible. On some of the projects, offsets ranging from 5 to 25%[37] were employed, based on the analysis and sound judgment of the respective witnesses. No witness believed that the so-called "offsets" would exceed the range of estimated savings, in any event.

105 The following illustration was excerpted from the testimony of Company Witness DeFelice, at page 15, wherein he depicts Avista's alternative capital investment proposal:

[37] The referenced "offsets" all pertain to reductions in rate base in the rate year – not expense. The net reduction to rate base for these "offsets" totaled approximately $2.05 million electric and $.471 million natural gas. (See Exh. No. ___ (DBD-9) pages 2 and 3, and Exhibit No. ___ (DBD-10), pages 2 and 3) The approximate impact on the Company's revenue requirement for these reductions in rate base is $352,000 electric and $76,000 natural gas.

Illustration 2

Avista's Alternate Capital Investment Proposal [1]
(Electric)



[1] Excludes Noxon 2009 and 2010 upgrades. Revenue Requirment for the Noxon capital investments is an additional $2.559M
[2] Includes 6 electric distribution projects, 4 Natural Gas Projects, and 3 General Plant Projects

106 This schematic summarizes the approach used by Avista in developing an "alternative" capital investment proposal, and translates the differences in terms of revenue requirement. It shows the impact of (1) simply carrying forward Staff's same "subset" of generation and transmission assets to year end, 2009 (thereby increasing Staff's revenue requirement by $3.380 M), as well as (2) capturing the miscellaneous items of distribution and general plant discussed immediately above (but only through July 31, 2009) (thereby adding an additional $2.264 M of revenue requirement). You will note that there is no proposal for the recovery of 2010 capital additions (except for the Noxon upgrade, otherwise agreed to by Staff). It otherwise simply "builds on" Staff's proposal to reflect plant that will be known and measurable, easily susceptible to audit, and with generous assumptions about any so-called "offsets." And, because it reflects no 2010 capital additions (except for Noxon), the portrayal is inherently conservative; if anything, it fails to properly "match" revenues, expenses and rate base during the rate year (all to the customers' advantage).

107 Where, at the end of the day, does this alternative analysis lead us? Mr. DeFelice, at page 16 of his Rebuttal Testimony (Exh. DBD-4T) provides a table that summarizes the capital revenue requirement and rate basis analysis of Avista's original request, as well as this "alternative approach" discussed above. The electric revenue requirement would remain essentially the same under either approach: For plant additions – Washington electric revenue requirement is $11.3 million under Avista's original request versus $11.4 million under Avista's "alternative" approach. For natural gas, this alternative approach would produce a revenue requirement of $894,000, as compared with the Company's original request of $1,313,000 of capital-related revenue requirement. As such, the alternative approach, which simply builds on Staff's analysis and factors in a conservative (i.e., generous) level of assumed "offsets," takes the Commission to essentially the same place. As such, it serves as further support for Avista's original proposal.[38]

C. Avista's Proposed Level of Costs Related to its Asset Management Program Should be Recovered.

108 Avista's Asset Management (AM) Program manages key electric transmission and distribution assets throughout their life to provide the best value for our customers. By minimizing life cycle costs and the costs to generate and deliver energy, the Company is able to maximize system reliability and value for our customers. (Exh. SJK-4T, p. 12, ll. 1-13) As explained by Mr. Kinney, this program began over five years ago when the Company consolidated many of its individual maintenance programs into a consolidated effort to maximize efficiency and provide flexibility. (Id.) As such, this program essentially consolidates existing programs with which Avista has had considerable experience, allowing the Company to reasonably plan for future expenditures.

[38] With respect to generation plant additions through the end of 2009, any supposed "offsets" or benefits would have already been included in the power supply adjustment reflected in the Aurora model, which assumes that these projects were available and in service at December 31, 2009.

109 Some of these programs include "vegetation management," in order to maintain over 12,000 miles of distribution circuits and 2,200 miles of transmission lines, and thereby minimize storm-related outages. It also includes "wood pole management," calling for a programatic replacement of distribution poles based upon a disciplined inspection program. As such, moneys expended for this Asset Management program will serve the company's customers, by contributing to system reliability and safety. (See Exh. SKJ-4T, pp. 12-14)[39]

110 Avista did more than base its adjustment on "merely budgeted costs" as suggested by Public Counsel. Instead, it is founded on "sound, historical experience, administered by employees in the Company with many years of utility experience," as explained by Ms. Andrews. (Exh. EMA-4T, p.19, ll. 17-20) It is important to note that neither Staff nor Public Counsel have otherwise identified any particular expenses that had been imprudently incurred as part of this program, nor have they demonstrated that such costs will not actually be incurred.

111 The Company's rebuttal testimony also speaks to whether or not there are any "offsetting factors" resulting from Avista's Asset Management Plan. While the program may produce savings for our customers over the long term, the majority of those savings will be observed in future years, inasmuch as the programs take "time to mature and provide positive results and the avoidance of future O&M costs and capital investments," as testified to by Mr. Kinney. (Exh. SKJ-4T, p. 14, ll. 10-19) Mr. Kinney went on to compare future electric maintenance costs both with and without asset management from 2010 through 2019, and concluded that the "net overall

---

[39] Even Mr. Larkin, Public Counsel's witness, acknowledges the importance of the program:

> "Avista's Asset Management program attempts to manage by minimizing life cycle costs and maximizing system reliability. The Asset Management program is relatively new, but consists of well-established programs such as vegetation management, wood pole inspections and transformer management, etc."

(Exh. HL-1T, p.16).

effect on O&M is a $100,000 increase in 2010 over the test period, i.e., no net offset." (Id. at p. 15, ll. 4-11)[40]

112 Nevertheless, in an effort to be conservative and incorporate any possible "offsetting factors" the Company provided information on an "alternative approach," that would reduce the share of program-related expenses, should the Commission deem an "offset" to be necessary. Those reductions or "offsets" are described in the rebuttal testimony of Company Witness Andrews (Exh. EMA-4T, pp. 21-22) which total $231,000, spread across several programs. Were one to incorporate those "offsets," this would provide an "alternative" revenue requirement adjustment for Asset Management of $2,797,000 for electric and $92,000 for gas.

D. **The Company's Proposed Adjustment for Expenses Related to Information Services is Well Supported**.

113 Mr. Kensok, Vice President and Chief Information Officer, presented detailed testimony regarding expenditures for "information services." (Exh. JMK-1T)[41] Mr. Kensok testified that the costs requested in this case are "known and measurable" and reflect costs associated with "existing technology and labor that are already employed. . . ." (Id. at p. 3, ll. 4-7) The Company did, however, propose to reduce its original revenue requirement request related to its Washington "information service" downward by $717,000 for electric and $182,000 for natural gas. (Exh. EMA-4T, p. 24, ll. 12-13) Since the filing of its case, Avista has elected to delay the "Work Management System" (used to schedule, track and account for customer projects and

[40] According to Mr. Kinney, when all of the asset management programs in this rate case excluding the vegetation management portion are combined, the net O&M savings is $2.05 million in 2010 compared to the test year. However, vegetation management will incur a net O&M cost increase of $1.02 million to insure a 5 year maintenance cycle is achieved. Also the Failed Electric Maintenance program costs are projected to increase by $1.12 million in 2010 based on the previous 5 year projected average. All of which caused him to conclude that the net overall effect on O&M is a $100,000 increase in 2010 over the test period. (Exh. SJK-4T, p. 15, ll. 4-12).

[41] He observed that during the period 2002 through 2005, the total Information Services budget at Avista was reduced by nearly 25% and, more importantly, the 2009 operating expense level is nearly at the same level as 2002. At the same time, however, the Company has completed and supported many additional system projects from which the customers are receiving additional benefit today, with little or no change in IS support costs. (Exh. JMK-1T, p. 2, ll. 20-25).

work activity) until a final business process design is completed sometime in 2010. At that time, this would result in capital expenditures in 2010 and associated increases and expense starting in 2011.[42]

114 What remains are costs related to supporting existing information technology applications prior to or during the test period (i.e., incremental labor and increased non-labor expense for software maintenance and license fees, software and hardware costs). As such, any offsets and/or benefits would have already been reflected in the operating areas where these applications are being utilized and would have been reflected in the Company's test period. (Exh. JMK-1T, p. 4, ll. 5-12)

115 The Company has provided information not only in testimony, but through discovery, on each expense-related item, demonstrating that the majority of these costs have been incurred (i.e., new employees have been hired, or invoices have been paid) or would soon be incurred prior to the end of 2009. Here again, no party has contested the prudence of any such expenditures or, for that matter, whether such expenditures will occur prior to the end of 2009. There are no additional 2010 capital or expense items in Avista's pro forma adjustment.

E. The Company Has Correctly Calculated the Production Property Adjustment

116 The production property adjustment is specifically designed for the purpose of adjusting the pro forma adjustment in the future rate year back to the historical test year in order to preserve the matching of customers, revenues, expenses and rate base during the historical year. (Exh. KON-1T, p. 20, ll. 21-24) As described by Mr. Norwood, in setting retail rates for the 2010 rate year, the pro forma rate base adjustments should be made to reflect the level of rate base that

[42] The Company has also reflected a $200,000 reduction in the expense related to the "Electronic Payment Service Provider" expense and also included a 20% reduction of the cost of the new "Mobile Dispatch Application" and the "Wireless Wide-Area Network Program" costs. All of these so-called "offsets," together with the delay in the "Work Management system" until 2011, serve to reduce the Company's original revenue requirement request by $717,000 for Washington electric and $182,000 for Washington natural gas. (Exh. JMK-1T, p. 10)

will be used to serve customers, and customers' kWh load, during 2010. We know that there will be more customers and higher loads (more kWh sales) for the 2010 rate year than the 2008 historical test year. Because retail rates are set using the lower number of customers and lower kWh sales for the 2008 test year, in order to preserve the "matching" principle, the pro forma rate base revenues and expenses for the 2010 rate year are adjusted back to the 2008 test year through the "production property adjustment." (Id. at p. 21)[43]

117 Mr. Norwood explained why it is important, in the ratemaking process, to first adjust rate base up from the 2008 test year to the 2010 rate year through pro forma adjustments, and then reduce it back from 2010 rate year to the 2008 test year. He explained that the embedded cost of utility facilities and customers' rates is lower than the incremental cost of facilities that will be in place for the 2010 rate year. As such, the only way for the Company to recover its costs to serve customers in 2010 is to pro form in the costs to serve them in 2010, and then reduce the level of rate base back in 2010 to a level that matches customers' load for the 2008 test year. (Id. at p. 22, ll. 12-19)[44] / [45]

118 All parties in this case agree that a "Production Property Adjustment" is necessary to fully complete the pro forma adjustment process. There is disagreement, however, regarding whether it should be applied to all production and transmission costs, even if they were not pro

[43] The production property adjustment is made using a "production property factor." This factor is "1 minus the ratio of 2008 test year customer loads divided by the 2010 rate year customer loads." (Exh. KON-1T, p. 21, ll. 15-19). For this rate case for Avista, the 2008 customer loads of 5,487,574 mWh divided by the customer loads of 5,591,052 mWh for the 2010 rate year, result in a production property factor of 1.85%. (Exh. KON-1T, p. 21, l. 15 – p. 22, l. 4). The pro forma rate base for 2010 is multiplied by the 98.15% factor (100% - 1.85%) to reduce the rate base back to the level that "matches" the level of customers' load for the 2008 year, which is used to set rates. This factor is then applied to both the production and transmission rate base. Retail rates are then set to recover less than the 2010 pro forma level of rate base, but as customers' loads grow to the expected level in 2010, the customers' loads in 2010 will provide the revenues that "match" the costs associated with the rate base that is used to serve them during the 2010 rate year. (Id.)

[44] The production property adjustment is also used for costs other than rate base. The adjustment is used in the same way for power supply expenses. First the power supply cost necessary to serve customer loads for the 2010 rate year are determined, and then the 2010 rate year power supply costs are discounted back to the 2008 test year using the production property adjustment, so there is a proper matching of pro forma power supply costs with the 2008 test year. (Exh. KON-1T, pp. 22-23).

[45] For its part, Avista only included capital additions through December 31, 2009.

formed to a future period. (See Exh. TLK-8T, p. 3) And that is the nub of the dispute with Staff.[46] Staff's Production Property Adjustment incorrectly assumes that all costs, even capital additions, are pro formed to 2010 levels, before there is any "discounting" back to the test period. In this way, Staff improperly discounts all costs as part of its pro forma adjustment, even if certain costs were not otherwise included in their pro forma adjustments.

119 The Company, on the other hand, properly applied the production factor depending on the time period for which costs were pro formed. That is to say, if costs were pro formed for 2010, they were adjusted back approximately 2 years to the test period. But if costs were only pro formed to 2009, they were reduced through the production property adjustment back approximately one year to the test period. Stated differently, if a cost has not been pro formed beyond the test period, it is not included in the production property adjustment. (Exh. TLK-8T, pp. 3-4) In the Company's case, all production and transmission rate base was only pro formed to December 2009. Staff, on the other hand, does not even fully pro form production and transmission rate base through 2009, and yet assumes these levels of plant additions are fully pro formed through the 2010 rate year, for purposes of computing its production property adjustment.

120 Only Avista's calculation properly preserves the "matching" of the pro formed costs with the test year. Because Avista's rate base adjustments were pro formed to December 2009, it's calculation of the production property factor properly reduced the pro forma rate base from 2009 to the test year using 2009 loads versus test period loads. (Id. at p. 5, ll. 8-10)[47] Staff's application of the production property adjustment to test period costs results in a level of cost

[46] Other technical corrections identified by Company Witness Knox in her Rebuttal Testimony (TLK-8T, pp. 8-12) were corrected by Staff in the revised testimony of Mr. Kermode.

[47] Costs that have not otherwise been pro formed beyond the test year have an "implied production factor" of zero (test year load divided by test year load equals 1) which results in no adjustment, as explained by Witness Knox. (Exh. TLK-8T, p. 5, ll. 8-13).

recovery beginning at a level even below the actual amounts for the test period, as illustrated by Witness Knox. (Exh. TLK-8T, p. 6) (See Illustration 1) This is true because Staff uses a "global approach" which encompasses all production and transmission costs with no recognition that some of the costs reflect only historical test period costs, and others only 2009 pro forma costs. (Id. at p. 7)[48]

F. **Public Counsel's Adjustment to Reduce Rate Base for "Injuries and Damages" is Flawed**.

121 Public Counsel's Witness Mr. Larkin has proposed an adjustment to reduce rate base for what it believed was Washington electric and natural gas "injuries and damages reserve account balances" included on the Company's balance sheet, as adjusted for deferred federal income taxes. (DFIT) (Exh. HL-1T, p. 29) Company Witness Andrews explained Avista's accounting method for financial statement purposes. (Exh. EMA-4T, p. 38) Avista estimates future potential losses and records an expense with a corresponding amount credited to its "injuries and damages" reserve account. If the Company ultimately settles a claim and payment is made, the net effect reduces the net reserve balance. It is important to note, however, that Avista does not recover the estimated cost recorded when the reserve is established for regulatory purposes; rather, the Company reverses all estimates accrued during the year and instead uses only the actual claims payment made (using a 6 year average). (Id.) In this manner, only actual claims that have been paid are included in the utilities cost of service. Accordingly, the Company has

---

[48] Public Counsel, for its part, through the testimony of Mr. Larkin (Exh. HL-1T) committed a number of very basic methodological errors, which were acknowledged during cross examination. (See Tr. pp. 698-709) First of all, Public Counsel's derivation of the revenue requirement failed to incorporate the agreed-upon level of future loads, as reflected in the Partial Settlement Stipulation. That Stipulation reduced the 2010 loads by 3% (from 5% to 2% from the end of the test period), but Mr. Larkin failed to recalculate the production property factor consistent with the lower 2010 load assumption. Doing so would increase Public Counsel's revenue requirement by approximately $6.4 million. (See Tr. p. 702, ll. 4-10)

Moreover, Public Counsel failed to incorporate the power supply adjustments otherwise agreed to in the Partial Settlement Stipulation, in order to update the production property adjustment. (See Tr. p. 708) Public Counsel's Response to Bench Request #2 (see Exh. B-5) purports to correct for these deficiencies.

not otherwise collected from ratepayers for the reserve that have been recorded for financial statement purposes only. (Id.)[49]

G. The Company's Labor Adjustment is Well-Supported by Current Survey Data.

122 In the Company's direct case, it began by annualizing the 2008 salary increases which went into effect on March 1, 2008 for administrative and union employees, and adjusted executive employee salaries to reflect actual salaries in 2008 for the current executive team. (Exh. EMA-4T, p. 6) Through rebuttal, the Company also adjusted the Company's non-executive and executive labor adjustments to reflect the 2009 actual increases paid to employees on March 1, 2009 (2.5% for administrative employees/0% for executives). (Id. at p.6, ll. 20-22) The Company then pro formed in a 2010 salary level of 2.8% for administrative and executive labor (below the current survey data) and adjusted the union labor for 2010 to reflect competitive wages paid elsewhere in the region.[50] (Id. at p. 7)

123 Staff, for its part, accepted the 2008 annualization of non-executive labor and the 2008 expense level for executive labor and included the non-officer 2009 adjustment at the originally requested 3.8%, but did not reduce the level of salaries to reflect the actual increases paid to employees on March 1, 2009 (2.5% for administrative employees). (See Exh. AMCL-1T, pp. 5-10) Public Counsel recognized the adjustment to reflect actual salaries paid in 2009. (Exh. HL-

[49] Public Counsel, for its part, committed two very basic errors in its calculation. First of all, it used a trial balance that was provided in response to a data request in order to determine the reserve amount, but failed to properly include the reserve contra-account that the Company otherwise uses to track all payments made for claims. As such, Public Counsel overstated the electric reserve by $7.4 million and overstated the natural gas reserve by $1.1 million The second error of Public Counsel consisted of its allocation of 100% of the system reserve to Washington, when approximately 35% of this reserve account should have been allocated to the Company's Idaho jurisdiction. (Exh. EMA-4T, p. 39)

Public Counsel recognizes this mistake, but argues that it was simply relying on information provided by the Company. The Company acknowledges that, while all of the information to perform the adjustment correctly was provided, it could have been clearer in explaining this source documentation to Public Counsel. Correcting for these errors reduce Public Counsel's proposed adjustment for "injuries and damages" to $14,000 for electric and $8,000 for natural gas.

[50] These downward adjustments to Avista's original labor adjustment served to reduce the electric revenue requirement by approximately $628,000 for administrative and union employees and $50,000 for executive employees. For natural gas, the net impact was a revenue requirement reduction of approximately $167,000 for administrative and union employees and $17,000 to executive employees. (Id. at p. 8, ll. 16-20)

1T, pp. 11-13) Neither Staff nor Public Counsel, however, made any additional salary adjustment for 2010, contending that such increases are not known and measurable.[51]

124 With respect to the 2010 pro forma adjustment, the Company has provided ample supporting documentation consisting of recent survey data for both union and non-union workers of the sort typically relied on by the Company in prior years to establish salary levels. For administrative and executive labor, a survey of recent studies conducted as of September of 2009, indicates an average expected increase of approximately 2.8% for all companies participating in the survey (3.2% for the Utilities and Energy Industry Sector, i.e., 2.8% is below that expected for utilities). These results are shown in Exh. EMA-8, p. 6. The Company, is therefore, proposing to reduce its pro forma 2010 increase from 3.8% to 2.8% for this case. (Exh. EMA-4T, p. 7, ll. 3-11)

125 Similarly, for union labor, the Company conducts a survey of journeyman/lineman classification wages in the Northwest, as shown in Exh. EMA-8, p. 7. This demonstrates that Avista's union employees are currently below the average wages paid by approximately 2%. (This survey includes, e.g., Puget Power, Idaho Power, and the PUD's.) It also demonstrates that if a pro forma union wage adjustment is not made in this case for 2010, the pro formed wage level would be under the average wage by approximately 6%. (Id. at p. 8, ll. 1-4)

126 Finally, Public Counsel, through Witness Larkin, proposed to reduce executive labor expense, by adjusting the 2008 level of executive salaries. Public Counsel argues that the percentage used to annualize the 2008 executive employee salaries should be no higher than that used to annualize administrative salaries, because it argues that the 2008 increases for executive officers were not known.

---

[51] Interestingly enough, Public Counsel, in Avista's recently concluded case (Docket No. UE-080416/UG-080417) supported the inclusion of a $1.19 million adjustment to capture pro forma, estimated non-officer compensation for the prospective rate period (2009). (Exh. EMA-4T, p. 10).

127 Public Counsel is wide of the mark. The actual executive salary information for 2008 for each officer was provided to all parties in this case, as explained by Witness Andrews. (Exh. EMA-4T, p. 11, ll. 5-13) Secondly, due to changes in the officer team and responsibilities, in order to determine the appropriate 2008 salary level, the Company did not simply annualize the test period (10/1/2007 to 9/30/2008) actual executive labor expenses, but rather used actual salary information for each executive charged to utility operations for the current executive team. (Id.)

128 For all of these reasons, the Company's adjustments to executive, administrative and union labor for 2008-2010 should be accepted as well supported, and, if anything, are "conservative" based on survey data of competitive salaries and wages paid in the industry and in the region.

H. Incentive Compensation.

129 The Company's use of a 6-year average, adjusted for CPI, for incentive pay is appropriate. Both Staff and Public Counsel reject the Company's pro forma incentive compensation adjustment based on a 6-year average, and argue that only the actual incentive compensation expense paid during the test year should be recognized. (See Exh. AMCL-1T (LaRue), pp. 10-12; Exh. HL-1T (Larkin), pp. 19-20). The Company's adjustment, reflecting a 6-year average of data, is particularly appropriate when costs can vary significantly from year-to-year, as is true with incentive expense. As noted by Company Witness Andrews:

> 130 Since annual Company incentive plan payouts can often vary year-to-year, the Company has chosen to propose an average of annual payouts. Often where there are revenues or expenses that can vary significantly from year-to-year and therefore uncertain as to the appropriate level, the Commission has utilized or approved averages to properly reflect a fair and reasonable level of revenue or expense to be included in customers' rates.

(EMA-4T, p. 14, ll. 16-24) (Emphasis added) The table set forth in Witness Andrews' Rebuttal Testimony, at page 14, demonstrates the variability of incentive expense over time. Indeed, the use of this average technique where costs fluctuate through time, has been used by the Commission elsewhere, such as for the "injuries and damages" adjustment, and in order to reflect transmission revenues that are presently included in Avista's rates. (Id. at p. 15, ll. 1-3) Other examples include adjustments for power plant availability and storm damages. (Id. at p. 16)

131 Interestingly enough, in Avista's recently concluded general rate cases (Docket Nos. UE-070804/UG-070805), the Commission Staff, itself, proposed the use of an average for purposes of arriving at a representative "incentive level," as explained in Witness Kermode's testimony in that docket. As it happened, the adjustment by Staff in the prior case resulted in a reduction to the Company's request, unlike here, where the Staff has switched gears, and has rejected an averaging approach, in order to further reduce Avista's revenue requirement. (Id. at p.16, ll.11-26) Staff and the Commission should be consistent in their use, over time, of an "averaging" technique.

132 Finally, it is important to note that these incentive payments will be made, based on defined targets. As explained by Company Witness Andrews, under the Company's incentive plan, payouts are made only if the O&M cost-per-customer targets are met or exceeded (along with other targets such as CAIDI, SAIFI, and customer satisfaction ratings). (Exh. EMA-4T, p. 17) And, the payments will only be made if such customer benefits are realized. (Id.) Finally, as with the wage/salary adjustment, neither Staff nor Public Counsel has demonstrated any imprudence whatsoever with respect to the design of the incentive program or the objective sought to be accomplished.

I. **The Company's Pro Forma Level of Directors' Fees and Board Meeting Expenses is Appropriate**.

133 While Staff makes no adjustment relating to Board of Directors' fees, Public Counsel proposes an arbitrary 50% reduction, without any showing of imprudence. Both Staff and Public Counsel, however, go on to propose a 50% sharing of Board meeting expenses.

134 Board of Directors' fees and meeting expenses, to begin with, are a necessary expense of doing business, as a publicly-traded utility. Fundamental governance of a utility, with an obligation to serve, requires the active involvement of a Board of Directors to provide strategic guidance and to maintain access to the public capital markets, allowing the utility to maintain the necessary infrastructure. (Exh. EMA-4T, p. 32) To begin with, there has been no demonstration that the overall level of Director compensation levels are out of line with industry averages; indeed, as explained by Company Witness Andrews, the Company's Directors are paid based on the market value for their services, as determined by periodic surveys. (Id. at p. 32) Public Counsel has arbitrarily reduced Board fees by 50%, without any demonstration that that would reflect an appropriate sharing between shareholders and customers. Were, however, the Commission to decide that some sharing of Director compensation is appropriate, then the Company would propose a 90% customer/10% shareholder percentage allocation. This would mirror the same allocation (90/10) used to divide executive compensation for the senior team between ratepayers and non-regulated operations, and therefore has a rational basis. It should be remembered that no party – including Staff and Public Counsel – contested this 90/10 allocation for officers in this case.

135 Public Counsel spent time cross-examining Company Witness Andrews with respect to a number of miscellaneous Board expense items relating to Board meetings, and certain gifts (e.g., a $76 crystal vase). (See Tr. pp. 558-577) Without even arguing the point, the Company's

proposal for a 90/10 split would more than offset any questioned items for these miscellaneous expenditures. [52]

J. There is no Basis for the Arbitrary Disallowance of 50% of D&O Insurance.

136 Both Staff and Public Counsel also arbitrarily remove 50% of the cost of the Company's Directors and Officers (D&O) insurance, so as to equally share the cost between ratepayers and shareholders.[53] (See Exh. DPK-1T, pp. 16-18; see Exh. HL-1T, pp. 21-23) They do so, however, without any demonstration whatsoever of imprudence; nor do they contend that the level or cost of coverage is inappropriate or that the coverage is otherwise unnecessary.[54]

137 D&O insurance is a means to address the financial risks attendant to serving as a Director or Officer of the Corporation, without which no capable individual would agree to serve in either capacity. As explained by Company Witness Andrews:

138
> The Company would be unable to attract or retain capable individuals for the Board of Directors or to otherwise serve as Officers. No qualified individual would agree to serve as a Board member or Officer without the benefit of such insurance. The fundamental governance and direction of the Company would not be possible without these individuals, therefore it is an essential part of the operation of a utility.

---

[52] A 90/10 split would result in an electric revenue requirement reduction for Directors' fees and meeting costs of $56,000 and $5,000, respectively. For natural gas, the revenue requirement reduction for Directors' fees and Directors' meetings would be $16,000 and $1,000, respectively. (Exh. EMA-4T, p. 33, ll. 5-11)

[53] Avista has purchased combined limits of $110 million in D&O liability insurance against potential claims made in 2008 and paid insurers $1.7 million for the policy. (It's self-insured retention was $2 million per claim.) For the 2009 renewal amount, Avista allocated 97% of this expense to utility operations, which was higher than 67% the Company had previously allocated to the utility. After the sale of Avista Energy in 2007, the Company's 2008 D&O insurance premium dropped, due to the sale of Avista Energy. After giving effect to this, the remaining D&O insurance premium for 2008 was not materially different than the 66% expensed to the utility operations in 2007. Moreover, the 2009 premium has dropped even further than that reflected in the 2008 test period. The Company has reflected this decrease in premium amounts for 2009 in its rebuttal case.

[54] Public Counsel also makes a calculation error in its removal of 50% of these costs. The Company and the other parties had otherwise agreed to update the test period D&O insurance level of expense; however, in the process of removing 50% of the test period insurance expense, Public Counsel used the earlier, and higher, estimate of expenses, as the base. This calculation error overstated Public Counsel's revenue requirement adjustment by $126,000 for electric and $32,000 for natural gas. (Exh. EMA-4T, p. 27, ll. 6-14)

(Exh. EMA-4T, p. 28, ll. 18-22) Indeed, even Ms. LaRue, of Staff explicitly acknowledges that "D&O insurance is a necessary cost to doing business." (Exh. AMCL-1T, p. 17, ll.3-6) She never explains, however, why this "necessary cost" should be only partially recovered through rates.

139 Neither Staff nor Public Counsel appreciate the purpose of D&O coverage. It is not to provide a "fund" for shareholders in the event of litigation; rather, its true purpose, in the first instance, is to protect Directors and Officers from the financial risk attendant to serving in a publicly-traded corporation. (Exh. EMA-4T, p.30, ll. 13-15) A qualified and competent Board of Directors and slate of officers is essential to a well-run utility, without which ratepayers may suffer.

140 Were the Commission, however to decide that some level of sharing of D&O coverage is appropriate, the Company would propose the same 90% customer/10% shareholder percentage split that it recommended with reference to Board compensation, and for the same reasons articulated above.[55] This would also be consistent with the 90/10 allocation to ratepayers/shareholders of executive compensation expense, which no party has disagreed with.

K. Other Miscellaneous Revisions to Revenue Requirement are not in Dispute.

141 The Company accepts Staff's proposed adjustment with respect to employee pension expense, increasing the Company's revenue requirement for electric by $551,000 and natural gas by $146,000. (Exh. EMA-4T, p. 18, ll. 11-20)

142 The Company also accepts Staff's adjustment with respect to property taxes, which revises the previous estimate to reflect actual information. (This revision reduces the revenue requirement requested by the Company for electric operations by $1,306,000 and for natural gas operations by $471,000.) (Id. at p. 33, ll. 17-22)

[55] This would equate to a further revenue requirement reduction of $72,000 for electric and $20,000 for natural gas. (Exh. EMA-4T, p. 31).

143 With respect to Colstrip mercury emissions O&M expense, the Company has reduced its original estimate of the cost required to mitigate mercury emissions from the Colstrip projects. Accordingly, the Company has incorporated costs that are approximately 50% less than previously anticipated, when the case was filed, thereby reducing the Company's requested level of expense to $969,000. (This amount was accepted by Staff as shown in its revised Exhibit (DPK-2).) This revised amount is greater than the 33% reduction previously recommended by Public Counsel. (Exh. EMA-4T, pp. 25-26)

144 Avista accepts Public Counsel's adjustment to reduce the amount of dues paid to the American Gas Association. For its part, Avista has also corrected for a misallocation of Edison Electric Institution dues that had been allocated to Washington gas service. (Exh. EMA-4T, p. 39-40)

145 With respect to Spokane River re-licensing costs, no party opposed the Company's original pro forma adjustment in its direct filing. However, since that time, the Company has updated that information for actual information to reflect the final system cost of securing a license (approximately $28.7 million versus the estimate of $30 million) and to extend the amortization period from 45 years to 50 years, consistent with the term of the license. (Exh. EMA-4T, p. 42) In addition, the Company has recognized $363,000 of actual annual labor costs that had previously been capitalized. The net impact of these proposed changes increases revenue requirement by $194,000 and reduces rate base by $795,000. (Id. at p. 42, ll. 8-21)

146 With respect to the Coeur d'Alene Tribal Settlement Agreement, Public Counsel proposed to reduce their recommended electric revenue requirement by $2.8 million and reduce rate base by $16.8 million, to reflect a matter that is now on appeal from this Commission's last rate order, as it relates to the CDA Tribe Settlement. (See Docket No. UE-080416) As explained by Ms. Andrews, however, that appeal, in and of itself, however, does not impact the

effectiveness of that prior order, which allowed for future recovery of the deferred amounts as part of new tariff filings in future rate cases. (Id. at p. 43, ll. 8-15)[56]

IV. THE COMPANY'S DECOUPLING MECHANISM SHOULD CONTINUE, WITH CERTAIN REVISIONS.

A. Introduction: The Rationale for the Continuation of the Mechanism Remains Intact.

147 Notwithstanding considerable testimony concerning programatic details and suggested revisions, the basic, underlying rationale of the Decoupling Mechanism remains unchallenged: to provide the Company with a reasonable opportunity to recover its Commission-approved fixed costs, while otherwise removing a substantial disincentive to increase natural gas DSM efforts. This rationale remains as true today as it was when the pilot program was first inaugurated 3 years ago.

148 The testimony of the Company demonstrated that the Mechanism has achieved its intended results. (1) The Company has increased its natural gas DSM efforts and results during the term of the pilot, and (2) it has allowed the Company to recover a portion of its fixed (natural gas distribution) costs through relatively small rate adjustments between general rate filings. (Exh. BJH-1T, p. 4, ll. 9-14) As further explained by Company Witness Norwood, the majority of testimony offered in opposition to the Mechanism dealt with measurement and verification procedures, related to energy efficiency programs, including program design, and low income energy efficiency savings. However, none of this goes to the underlying rationale supporting a continuation of the Decoupling program. According to Mr. Norwood:

149 > In my opinion, none of these arguments address the rationale of the Mechanism or justify its outright termination. The Mechanism removed the disincentive for the Company to expand its natural gas DSM offerings, both through increased

[56] Lastly, the "Restate Debt Adjustment" will change based on any final adjustments made to rate base by the Commission in its Order. (Neither Staff nor Public Counsel otherwise opposed the adjustment calculation as originally proposed by the Company.) Finally, certain errors in the "conversion factor" were corrected by the Company in its revised revenue requirement calculations in its rebuttal filing, and were not contested by any party. (Id. at p. 45)

> programatic offerings and non-programatic messaging. The pilot shows that the overall Mechanism works, removes the disincentive for increased DSM activity, allows the Company to recover fixed costs previously approved by the Commission, and therefore shoulder be continued, with certain modifications.

(Emphasis in the original) (Exh. KON-1T, p. 32, ll. 11-18) Indeed, Public Counsel Witness Brosch acknowledged that lost margin attributable to DSM has <u>increased</u> in the last decade. (Tr. p. 1174) Even Mr. Brosch conceded that this Commission could and should structure a "Mechanism" to account for lost margin:

150 . . . If you believe that there should be explicit compensation for calculated lost margins arising from utility-sponsored DSM, <u>then you could structure a Mechanism and perhaps should structure a Mechanism</u> to account for those lost margins. . . .

(Emphasis added) (Tr. p. 1169, ll. 20-24) While other means for accomplishing this might be explored in the future, e.g., explicit DSM incentives, equity "kickers" for DSM or rate basing of DSM, none of these are incompatible with a continuation of the Decoupling Mechanism.

151 The following section of the Brief will provide a brief description of the program, along with proposed revisions to the Mechanism. It will also discuss the actual DSM savings and expenditures, as verified by an independent consultant (Titus), both before and as a result of the Mechanism. It will also discuss ways to improve the energy efficiency measurement and verification procedures, through a proposed collaborative to address specific shortcomings identified by Public Counsel. It will finally address the impact of the Mechanism on low income customers, both with respect to costs and savings, as well as a proposed "limited income test" to insure sufficient expenditures in that sector.

B. <u>Description of the Program Along with Proposed Revisions</u>.

152 Avista's existing Decoupling program is quite modest in terms of what it seeks to accomplish. First of all, unlike other Mechanisms implemented elsewhere in the Country,

Avista's program factors out weather, and the impact it would have on the recovery of fixed costs. As such, one of the most significant factors affecting the Company's "risk" associated with the recovery of fixed costs is not even addressed by the Mechanism.[57]

153 Moreover, the Company, through rebuttal, is proposing to recover only up to 70% of the deferral, assuming 100% of DSM savings are achieved. (Instead of the current 90% maximum recovery level.) In addition, the level of deferred recovery under the Mechanism is subject to (a) an annual earnings test, and (b) a DSM test. These tests are calculated independently, with the test resulting in the lowest surcharge amount being utilized. (Exh. BJH-1T, pp. 15-16)[58] Furthermore, the Company retains an independent third party to audit the results of DSM savings reported for Decoupling purposes. And after applying the "earnings" and "DSM tests," the amount of any rate increase resulting from the adjustment is subject to an annual cap or limit of 2% (i.e., the annual surcharge cannot exceed a 2% rate increase in any year). (Exh. BJH-1T, p. 17) In it's rebuttal testimony, the Company has also proposed to add a limited income test, whereby 5% of programatic DSM savings must come from the limited income sector. Finally, the methodologies used to determine the deferrals are all based on Commission-approved methods for the determination of unbilled revenues and weather normalization. In sum, by removing the effects of weather, and given the various programatic features discussed above, it would be fair to characterize Avista's Mechanism as, in a sense, "Decoupling-Lite." It is a bare-

---

[57] This Brief will return to that point, in due course, as part of the discussion of why a 25 basis point reduction should not be made to natural gas return on equity, should the Mechanism continue.

[58] If the Company's "Commission-basis" rate of return for Washington gas operation exceeds the authorized rate of return, any proposed surcharge is reduced to bring the rate of return down to the Commission authorized level. Moreover, under the "DSM test" certain target levels of savings (based on the Integrated Resource Plan) must be met, or the amounts deferred will be reduced accordingly. (See Exh. BJH-1T, pp. 15-16).

bones approach to partially address the recovery (70%) of lost margin, while removing a disincentive to promote DSM.[59]

154 Chairman Goltz, also asked the parties, in their Briefs, to provide survey information of what other jurisdictions are doing, by way of addressing the Decoupling issue. (Tr. p. 1228) Appendix C to this Brief provides a summary compilation of efforts conducted elsewhere, further demonstrating that Avista's existing Mechanism is, in a very real sense, less ambitious than those implemented elsewhere, with numerous tests and built-in safeguards.

C. **During the Term of the Mechanism, Overall Natural Gas DSM Acquisition Levels Increased**.

155 As testified to by Company Witness Powell, overall DSM acquisition increased during the term of the pilot program.[60] (Exh. JP-1T) On October 22, 2009, however, Avista submitted a revised filing in UG-091399 (Avista's Proposed Natural Gas Decoupling Adjustment). In that filing, Avista reduced its claimed therm savings from 1,821,298 to 1,568,856, which was still 110% of the IRP target level of savings 1,425,070. However, for purposes of settling the matter with Staff and Public Counsel in the context of UG-091399, the Company agreed to a reduced level of fixed cost recovery (80%), without otherwise agreeing with Staff and Public Counsel energy efficiency therm savings estimates. The revised Decoupling surcharge tariff (Sch. 159), which reflects this agreement, was allowed to go into effect by the Commission on November 1, 2009.

---

[59] In his testimony, Mr. Norwood noted that most utilities in the Northwest, as well as California, already have some form of Decoupling:

Commission	Utility	Year	Type of Decoupling
California	Sempra, PG&E, SoCal Edison	1978-1982	Electric and Natural Gas
Idaho	Idaho Power	2005	Electric
Oregon	Cascade Natural Gas	2006	Natural Gas
Washington	Cascade Natural Gas	2007	Natural Gas
Oregon	Northwest Natural	2007	Natural Gas
Oregon	Portland General Electric	2009	Electric

(Exh. KON-1T, p. 37)

[60] Moreover, during the Decoupling period, natural gas DSM program expenditures increased from $2.4 million to $6.3 million. (Exh. JP-3T, pp.12-13)

156 Nevertheless, the Company exceeded its Integrated Resource Plan acquisition targets in 2007 and 2008. It is important to recognize that the level of DSM acquisition for each of these calendar years was submitted to an independent consultant firm (Research Into Action/Nexant) for independent verification. Avista, for its part, simply supplied the necessary data to support the claimed levels of DSM acquisition. (Exh. JP-3T at p. 2, ll. 11-17) Accordingly, Avista has demonstrated that overall DSM acquisition met or exceeded target levels established in the IRP process, and overall DSM savings, including the limited income sector, actually increased during the pilot period.

157 Nor is it fair to suggest, as does Public Counsel Witness Brosch, that the Mechanism is "overly broad" in that it captures the effect of declining use-per-customer beyond purely "programatic" DSM savings. (See Exh.MLB-1T, p. 13) Non-programatic DSM efforts, such as the "Every Little Bit" program, have also materially contributed to customers undertaking no-cost or low-cost steps toward being more energy efficient, through the customer education process. (Exh. KON-1T, p. 34) As explained by Mr. Norwood, this program encourages customers to adjust thermostats, replace dirty furnace filters, turn down hot water tank temperatures, and otherwise implement a host of activities such as low-flow showerheads, all of which serve to reduce natural gas consumption, "well beyond that which is specifically measured in the Company's DSM programs." (Id. at p. 34, ll. 11-17)

158 Various parties, however, have argued that the Company would have been very active in promoting DSM, even in the absence of a Decoupling Mechanism, citing to the Company's electric DSM efforts, and efforts in the State of Idaho. As explained by Mr. Norwood, however:

159 > The increased emphasis on DSM by the Company in the last couple of years has been done with the expectation that the Company would have some Mechanism to recover fixed costs associated with its DSM efforts. The presence, or lack thereof, of some Mechanism for fixed cost recovery is a major factor that will be considered as the Company develops its future DSM plans. (Emphasis added)

(Exh. KON-1T, p. 36, ll. 18-21)

D. The New Customer Adjustment is Integral to the Mechanism.

160 Public Counsel Witness Brosch takes issue with the inclusion of the "new customer adjustment" in the design of the current Mechanism. (Exh. MLB-1T, p. 3) As explained by Company Witness Hirschkorn, however, this adjustment is necessary in order to provide for an "apples to apples" comparison – i.e., a "comparison of the usage for customers during the test year to the usage for those same customers for the current period." (Exh. BJH-8T, p. 2, ll. 7-11) In other words, to the extent that the Company has added customers since the test year, these new customers serve to increase therm sales as compared to the base period therm sales. Therefore, as part of the monthly deferral calculation, a "new customer adjustment" is necessary to remove the cumulative usage for customers added since the base period. (Id.)

161 It should be remembered that the purpose of the Mechanism, after all, is to recover (or refund) the difference between the (weather-normalized) fixed costs received by the Company, as compared to the level of fixed costs during the corresponding month of the test year approved by the Commission in the Company's last general rate filing. Stated differently, the objective is to determine whether the therm usage included in the last rate case has increased or decreased for the same customer base. (Exh. BJH-8T, p. 2, ll. 14-19) In fact, Mr. Hirschkorn in its rebuttal testimony, provided a simple illustration of the impact of failing to remove new customers' usage from current therm sales, demonstrating how it would appear that the Company would over-collect a substantial amount of fixed costs, in the absence of a "new customer adjustment." (Exh. BJH-8T, p. 5, ll. 1-20) This prompted Mr. Hirschkorn to conclude that such an adjustment is a "critical component" of the Mechanism in order to allow for a true "apples to apples" comparison of usage during the test year to usage during the current period. (Id. at pp. 5-6)

E. Staff's Proposal to Increase the Schedule 101 Customer Charge is Insufficient.

162 Staff Witness Reynolds' proposal to increase the Schedule 101 customer charge to $10 per month (and thereby eliminate Decoupling) would not otherwise adequately substitute for Decoupling. It would simply be insufficient in its attempt to recover fixed costs. As explained by Company Witness Hirschkorn, the monthly customer charge would need to be increased to <u>$17.44</u> in order to provide the same level of weather-normalized fixed cost recovery under the Decoupling Mechanism. (Exh. BJH-8T, p. 8) And, importantly, this is based on the Company's <u>revised</u> Decoupling deferral proposal to recover only up to 70% of lost margin – rather than the present 90% recovery. (<u>Id</u>.) If the Company were to truly recover all of its fixed costs approved in the prior rate case, the basic charge would have to increase to <u>$22.45</u>. (<u>Id</u>.)

163 It is important to recognize that the average fixed cost for <u>new</u> <u>customers</u> is actually <u>in excess</u> of the average margin received. (Exh. KON-1T, p. 44, ll. 14-15) The average fixed cost to serve new customers in 2007-2008 was $26.05, as compared with the new margin actually received per customer of only $22.45. Accordingly, the Company does <u>not</u> realize new margin in excess of its incremental cost to serve new customers. Nor does the Mechanism, itself, allow the Company to recover more margin from new customers than the costs to serve them. (<u>Id</u>.)[61]/[62]

---

[61] As compared with the Company's more modest Decoupling Mechanism that excludes weather, incorporates a variety of tests and only seeks to recover 70% of the deferrals, other "full Decoupling Mechanisms" were discussed by Staff Witness Reynolds:

> Q. Okay. And where you said you reviewed other materials, this is huge, but, you know, is this basic structure we have now, and this is still basically the structure with some tweaks that Ms. Glaser proposes, is that being done in other states or other countries to your knowledge?
>
> A. I'm not sure. The materials that I – that are out there that are, you know, kind of generally available tend to be <u>talking about full Decoupling Mechanisms, without any limits, without the removal of weather normalization, without the partial [sic] so that it's only recovering may be 70% or 90%</u>. And so it's very – actually it was difficult to find materials that talked about these special Decoupling Mechanisms.

(Tr. p. 1280, ll. 10-24).

[62] Nor would a special $3.00 basic charge for low income customers, as suggested by Staff Witness Reynolds, be administratively feasible. As explained by Mr. Norwood, the administration of such a program would be

F. **The Existing Mechanism is Simple and Straight Forward**.

164 Notwithstanding the best efforts of Public Counsel to make the Mechanism appear to be more complicated than it in fact is, the Mechanism, at its heart, is simple and straightforward, as testified to by Mr. Norwood. (Exh. KON-1T, pp. 42-43) The two most complicated calculations consist of the "weather adjustment" and the adjustment for "unbilled therms," both of which are used routinely in general rate case filings, and have been approved by this Commission. The parties are (or should be) well-familiar with these adjustments over the years. (Indeed, the ongoing use of the "weather adjustment" was acknowledged by Staff Witness Reynolds during cross examination.) (See, e.g., Tr. p. 1278, p. 1285) Public Counsel and Staff may point to the amount of time spent by the parties in developing the Evaluation Plan and reviewing the work of the independent consultant. That, however, was with reference to the initial review of the pilot program, and going forward, the time spent evaluating the Mechanism should substantially decrease. (Exh. KON-1T, p. 43)

165 Although much attention was paid to perceived shortcomings in the measurement and verification process related to the Company's energy efficiency programs, that will be the subject of a separate collaborative, to address certain concerns raised by Staff and Public Counsel. The purpose of the pilot program, after all, is to identify any shortcomings and make any mid-course corrections. This does not argue for rejection of any continuation of the Decoupling program, whatsoever, as inferred by Public Counsel. Again, don't "throw the baby out with the bath water."[63]

G. **The Company has Proposed Improvements to the Energy Efficiency Measurement and Verification**.

---

burdensome, if not impossible, both in terms of computer programing and in terms of administrative complexity. (See Rebuttal Testimony of Norwood, p. 46, ll. 1-10).

[63] For a more complete discussion of the mechanics of the current Decoupling Mechanism, please see Hirschkorn's direct testimony. (Exh. BJH-1 at, pp. 13-19).

166 In its testimony, the Company has acknowledged that, based on what was learned through the Decoupling pilot program, there is a need for improvement in the area of measurement and verification of DSM savings. (Exh. KON-1T, p. 46, ll. 15-19) As explained by Company Witness Norwood, however, "these issues, <u>are independent of</u> the decision related to the continuation of the Decoupling Mechanism. Improvements to DSM measurement and verification will occur, whether the Decoupling Mechanism is continued or not." (<u>Id</u>.) To this end, the Company is developing a revised measurement and verification approach and will file these protocols with the Commission no later than September 30, 2010. (<u>Id</u>. at p. 46, l. 20 – p. 47, l. 7)[64]

167 This Brief, however, will further elaborate on a few of the issues raised by Public Counsel in this regard. It should be recalled, at the outset, that Avista's claimed DSM acquisitions for each of the calendar years of 2006-2008 were submitted to an independent consulting firm (Research Into Action/Nexant) for verification. These consultants developed and executed a methodology for the review and the revision of any claimed DSM acquisitions; Avista simply supplied the requested data to support its claimed savings. (JP-3T, p. 2, ll. 11-17) It is important to recognize that this procedure, and the manner in which the independent verification was conducted, was precisely what was called for in the Settlement Agreement in Docket UG-060518, which established the pilot program. Section F of that agreement provides as follows:

168
> . . . the Company will retain an independent third party to audit the results of DSM savings reported for Decoupling purposes. This independent auditor will be chosen through an 'RFP' process reviewed and approved by the parties to this Settlement Agreement. The scope of the audit will include an appropriate sampling of projects to verify the work completed, the savings recorded, and a

[64] As explained in the rebuttal testimony of Company Witness Powell, Avista will convene a group of interested parties, as part of a collaboration process, to outline the proper measurement and verification protocols going forward and will review these with the Triple-E Board, and will otherwise incorporate these into its 2010 DSM Business Plan. (<u>Id</u>.; <u>see</u> <u>also</u> Exh. JP-1T, p. 8)

> review of the engineering estimates used to estimate the savings. (Emphasis added)

(See Exh. JP-3T, p. 3, ll. 1-6) Even though several parties have asserted that a "physical" measurement of energy savings – not an "engineering estimate" – should have been necessary part of the verification process, that was not what was explicitly agreed to as part of the settlement agreement set forth above. Rather, the independent analysis was to be conducted based on "engineering estimates" – as opposed to independent physical measurement of metered savings. (Id. at p. 3, ll. 7-14)[65]

169 The Decoupling Evaluation Report (Exh. BJH-2a) recommended the use of professional engineers or "certified energy managers" to perform pre- and/or post-installation audits and energy usage measurement. (Exh. JP-1T, p. 7, ll. 1-5) As mentioned above, Avista is in the process of revising its protocols to incorporate these suggestions.[66]

170 The concerns of Public Counsel, in this regard, have been overstated and were based on a faulty sampling methodology. As explained by Company Witness Powell, the independent consultants who verified the savings did so based on a random sample of projects over the 3 year Decoupling pilot program. Public Counsel, however, while screening a very large number of projects (over 20,000 by their own estimate), only selected 11 projects completed in 2008 and 18 projects completed in 2007 that appeared to have the greatest overestimate of savings based on the information contained within the database. (Exh. JP-3T, p. 6, ll. 1-5) (See MMK-1T, p. 16) As explained by Mr. Powell, a non-random sampling of projects should not be extrapolated to a

---

[65] The means currently used to measure the savings from natural gas DSM programs were described by Witness Powell. He explained a variety of methods are used, all of which comply with the International Performance Measurement and Verification Protocol Standards. These methods include engineering estimates applying industry-standard energy end-use models, which are augmented by actual field measurements when useful and achievable. (Exh. JP-1T, p. 7).

[66] In doing so, it has developed a measurement evaluation and verification work plan that places increased emphasis upon the physical measurement of energy savings and other key inputs into the engineering calculations leading to estimates of energy savings. (Exh. JP-3T, p. 4, ll. 6-10) The Company is welcoming additional input from other stakeholder interests, as part of the collaborative process.

larger population of projects and conclusions drawn, particularly when these sample projects "are a small and highly-non-representative portion of the overall program." (See testimony of Powell, Exh. JP-3T, p. 6, ll. 8-10)[67]

171 In summary, the pilot program accomplished its intended purpose: It identified any areas for improvement, most notably measurement and verification – and Avista intends to address those through revised protocols incorporating the suggestions of the parties.

H. The Interests of Low Income Customers Have Been Served Through the Decoupling Program.

172 Avista implements its limited income DSM programs through annual contracts with 6 Community Action Agencies in Washington. (Exh. JP-1T, p. 8, l. 15, p. 9, l. 18) These agencies receive annual contracts that allow them to expend the funds for pre-qualified energy-efficiency measures, as well as other projects that receive individual approval from the Company. In this manner, the agencies are provided with the maximum amount of flexibility in the use of these expenditures. (Id. at p. 9, ll. 11-14) This funding by Avista is further leveraged by the agencies to obtain additional matching funds from state and other governmental funding sources.

173 The unchallenged fact remains that the population of limited income customers saw a 13% increase in DSM savings during the Decoupling period, along with a 43% increase in expenditures. (Exh. KON-1T, p. 47, ll. 11-20) (Exh. JP-1T, pp. 8-10) Moreover, there was a net benefit to the low income customer group as a whole from investments in energy efficiency projects, after taking into account both the Decoupling and DSM surcharges combined. (Exh.

[67] Public Counsel's concerns over energy savings related to residential space heat efficiency programs (Exh. MMK-1T) were based on an incorrect assumption that there was an error in Avista's claimed energy savings, when in fact those programatic savings simply changed through time based on jurisdictional allocations between Idaho and Washington in 2006. (Exh. JP-3T, p. 7, ll. 1-9) Moreover, Public Counsel's concerns (Exh. MMK-1T, p.27) that there were inconsistencies in claimed savings for high-efficiency window programs were simply due to their misunderstanding of the data and the use of "measurement codes" – i.e., the reported energy savings were based on the number of project measurement codes completed, not the number of participants, as believed by Public Counsel. Public Counsel mistakenly assumed that the number of measurement codes was consistently equal to the number of participants. (Exh. JP-3T, p. 7, l. 14 – p. 8, l. 10).

KON-1T, p. 48, ll. 6-9) As explained by Company Witness Powell, just examining "year 1" savings alone, the "average limited income customer will save $42.34 versus their billed surcharges of $14.79, for a net benefit of $27.55." (Exh. JP-3T, p. 12, ll. 11-17) These investments in energy efficiency will create long term net savings to customers over the life of the measures. (Id.)[68]

174 To assure the continuation of low income DSM funding, the Company is proposing, by way of a revision to the Mechanism, an additional limited income test, whereby 5% of programatic DSM savings must come from the limited income sector. Mechanics of this test are further described in Mr. Norwood's Rebuttal Testimony at p. 49. (Exh. KON-1T, p. 49, ll. 1-19) In the final analysis, however, it is well to recognize that the ultimate control over the acquisition of savings from the limited income sector falls with the CAP agencies, and not with the Company. In that regard, the Company can provide agencies with as much guidance and flexibility as possible when working with their constituency, allowing them to allocate funds in the most critical areas; Agencies, however, may choose to allocate more to electric DSM acquisition than natural gas. (Exh. KON-1T, p. 49, ll. 3-9)[69]

I. Given the Design of the Decoupling Program, it would be Inappropriate to Reduce Gas ROE by 25 Basis Points.

175 Public Counsel, through Witness Gorman, suggests that there should be a 25 basis point reduction in the allowed return on equity (ROE), should the Mechanism continue. (See Exhibit MPG-1T) The Company, through Witness Hirschkorn, explained why the Mechanism does not

---

[68] See "Evaluation of Avista Natural Gas Decoupling Mechanism Pilot" report (BJH-2a, p. 83) (Table K11-C). This notes that the $14.79 includes $10.05 of average Schedule 191 DSM costs and $4.74 of average Schedule 159 Decoupling costs.

[69] Moreover, limited income DSM provides for full funding of DSM measures, as compared with approximately 50% of funding for the incremental cost of DSM for non-limited income customers. (Exh. JP-3T, p. 11, ll. 11-17) Accordingly, while the Company did ramp up limited income DSM (i.e., savings increased by 13% and funding increased by 43%) this increase was not as great as for the non-limited income population, inasmuch as the low-income customers already received 100% funding of DSM measures.

significantly affect the Company's business risk and, therefore, an adjustment to the Company's authorized return on equity is not warranted. (Exh. BJH-1 at p. 20, l. 10 - p. 21, l. 2)

176 First of all, the Mechanism captures only changes in residential and small commercial customers' usage resulting from natural gas conservation, energy efficiency and price elasticity. He explained that it does not capture: (1) changes in large customer usage often resulting from changes in business or economic conditions, or (2) changes in customer usage resulting from abnormal weather. (Id.) As observed by Mr. Hirschkorn, "these changes in customer usage that are not included in the Company's Mechanism are generally more substantial and volatile than those that are included." (Id.)

177 Furthermore, the Mechanism simply provides for the recovery of fixed costs that were previously approved by the Commission in prior proceedings; to the extent these approved fixed costs increase over time, the Mechanism does not provide for the recovery of those changes in costs. (Id.) As such, Avista continues to bear the risk of changes in these costs between general rate cases.

178 Finally, the Mechanism includes an "earnings test" that limits any Decoupling rate adjustment based on the Company's authorized rate of return. This assures that the Company will not "over-earn," as a result of the recovery of previously-approved fixed costs.

179 Significantly, the Company has proposed a further revision to the program which would reduce the maximum recovery of fixed costs from 90% to 70%. (Translated: This would provide the Company an opportunity to recover only up to 70% of its previously allowed fixed costs.) As noted by Mr. Hirschkorn this recovery of only 70% also takes into account lower customer usage due to the general economic downturn. (Tr. p. 1150)

180 A reduction to ROE of 25 basis points would reduce natural gas revenues to the Company by approximately $300,000 per year, as explained by Mr. Norwood. (Exh. KON-1T, p.

38, ll. 5-9) The proposed reduction in the recovery of fixed costs to 70%, would, itself, represent a reduction in the recovery of fixed costs by the Company in the "same order of magnitude." (Id.) For this reason alone, to also adopt an ROE reduction together with the Company's proposed percentage reduction to 70%, "would substantially undermine the effectiveness and objective of the Mechanism," as noted by Mr. Norwood. (Id.) For all of the foregoing reasons, no further reduction in ROE is appropriate, if the Mechanism continues. The Mechanism ("Decoupling-Lite") already factors out changes in usage due to abnormal weather and fluctuations in commercial and industrial load due to economic conditions. The Company still remains at risk for increasing costs beyond levels approved by the Commission, and the reduction in fixed costs recovery from 90% to 70% otherwise still puts the Company "at risk" for fixed cost recovery. [70]

J. Conclusion: The Decoupling Mechanism Should Be Continued, With Certain Suggested Revisions.

181 The foregoing demonstrates that the underlying rationale of the Decoupling program remains intact. The Company should be provided with a reasonable opportunity to recover fixed costs previously approved by the Commission, while removing the disincentive to continue to actively support DSM investment. The design of the program, which removes the impact of weather and economic circumstances affecting large customer load, makes it much less ambitious than other Decoupling programs approved elsewhere. [See Appendix C for a survey of other approved programs.] During the life of the pilot program, increased levels of DSM savings and program expenditures have been observed. While additional work needs to be done with respect to overall measurement and verification of DSM savings, those shortcomings have been identified and work is already underway to provide needed revisions. These measurement and verification issues are independent of the Decoupling Mechanism itself. Low-income customers

[70] Public Counsel Witness Brosch acknowledges that only two states, to the best of his knowledge, have accepted any sort of "offset" to ROE for Decoupling. (Tr. p. 465, l.14, p.466, l.10).

are also enjoying net benefits, and will be assured continuing levels of funding through an additional "low-income test." Finally, the Company has suggested a further revision, by proposing to recover only up to 70% of fixed costs (if 100% of DSM savings are achieved), as a further accommodation to account for the effects of the economic downturn on customer usage.

182 This program has been subject to intense scrutiny during its 3 year "pilot" phase. This included the very active involvement of all parties and the issuance of an extensive report by an independent consultant (Titus) verifying the increased level of DSM activity through the term of the pilot. In recent memory, no "pilot" program has been studied more intensely.[71]

183 Accordingly, the Commission has before it the evidence and argument it needs to support the continuation of the Mechanism.

V. CONCLUSION.

184 The Company respectfully requests that the Commission approve the terms of the proposed Partial Settlement Stipulation, addressing cost of capital, power supply issues and rate spread and rate design. Moreover, the evidence supports the full inclusion of the Lancaster PPA, and attendant transportation/transmission contracts, in base rates. It represents an extraordinary opportunity to meet long term resource needs with facilities in the Company's service territory, doing so in a manner that is consistent with the Company's integrated resource planning efforts.

185 With respect to the remaining revenue requirement issues, the Company has provided its view with respect to the "guiding principles" for pro forma adjustments. It has demonstrated that its capital additions and other pro forma adjustments related to asset management and information services, are known and measurable, include any appropriate "offsets," and provide

[71] Moreover, Company Witness Hirschkorn, at pp. 19-23 of his Direct Testimony (BJH-1AT) addresses how every item set forth in this Commission's Order No. 4 in Docket No. UE-050684, dated April 17, 2006 has been addressed. In that Order, the Commission outlined items that PacifiCorp should include, at a minimum, if it were to seek a Decoupling Mechanism.

for a "matching" of revenues, expense and rate base. Other adjustments related to labor, incentives, directors' fees, expenses and insurance are also well supported. Taken in total, this supports Avista's revised revenue requirement of $37.5 million of needed rate relief for its electric operations and $2.8 million of rate relief for natural gas.

186 Finally, the Commission should continue the Decoupling Mechanism, with appropriate revisions, in order to address a very real issue involving the recovery of fixed costs, in light of increased emphasis on DSM expenditures.

RESPECTFULLY SUBMITTED this ____ day of November, 2009.

David J. Meyer, Vice President and Chief Counsel
for Regulatory and Governmental Affairs

I:\Spodocs\11150\00001\plead\00761275.DOC:lg