BEFORE THE WASHINGTON STATE
UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION,	)	DOCKETS UE-090134 and UG-090135 *(consolidated)*
Complainant,	)	
v.	)	ORDER 10
AVISTA CORPORATION, d/b/a AVISTA UTILITIES,	)	
Respondent.	)	
. . . .	)	
In the Matter of the Petition of	)	DOCKET UG-060518 *(consolidated)*
AVISTA CORPORATION, d/b/a AVISTA UTILITIES,	)	ORDER 10
For an Order Authorizing Implementation of a Natural Gas Decoupling Mechanism and to Record Accounting Entries Associated With the Mechanism.	)	FINAL ORDER REJECTING TARIFF FILING; APPROVING AND ADOPTING MULTI-PARTY PARTIAL SETTLEMENT STIPULATION; DEFERRING LANCASTER COSTS; EXTENDING DECOUPLING MECHANISM; AUTHORIZING TARIFF FILING; AND REQUIRING COMPLIANCE FILING
. . . .	)	

1 ***Synopsis:*** *The Commission rejects revised tariff sheets Avista Corporation (Avista) filed on January 23, 2009, but authorizes and requires the Company to file tariff sheets that will result in increases of about 2.8 percent for electric rates and 0.25 percent for natural gas rates, which are found on the record of this proceeding to be fair, just, reasonable and sufficient. In approving these rate increases, the Commission approves and adopts a Multi-Party Partial Settlement Stipulation filed by the parties to this general rate case that resolves the overall cost of capital, the majority of power supply costs, and various other issues. Among several contested*

issues, the Commission denies the Company's proposed pro forma adjustments that are not demonstrated to be known and measurable and not offset by other factors, but accepts many proposed by Commission Staff. Further, the Commission authorizes Avista to defer its costs associated with the Lancaster power purchase agreement for possible later recovery, determining that Avista failed to make various factual and other showings that are prerequisite to immediate inclusion of such power costs in rates. These include failure to make the requisite showing of a binding agreement to purchase the power from the Lancaster plant, failure to make the required affiliated interest filing in compliance with RCW 80.16, and failure to demonstrate that this new power purchase agreement complies with the greenhouse gas emissions limits in RCW 80.80. Accordingly, the Commission will consider the recovery of the Lancaster costs in a later proceeding once those prerequisite showings have been made. In addition, we decline the Company's request to prematurely terminate the energy recovery mechanism (ERM) surcharge. Finally, the Commission approves a continuation of Avista's decoupling mechanism, with modifications including a lower maximum deferral rate of recovery for lost margins.

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SUMMARY

2 **PROCEEDINGS:** On January 23, 2009, Avista Corporation d/b/a Avista Utilities (Avista or Company) filed with the Washington Utilities and Transportation Commission (Commission) revisions to its currently effective Tariff WN U-28, Electric Service in Docket UE-090134, and revisions to its currently effective Tariff WN U-29, Gas Service in Docket UG-090135. The revisions proposed a general rate increase of $69.8 million, or 16.0 percent, for electric service and $4.9 million, or 2.4 percent, for gas service. Avista also proposed to decrease the current Energy Recovery Mechanism surcharge by $32.4 million, or 7.4 percent, resulting in an overall net increase of 8.6 percent for electric rates. The Company also sought to increase its overall rate of return from 8.22 percent to 8.68 percent. The Commission suspended the filings on February 3, 2009, prior to their stated effective date of February 23, 2009, and set the matter for hearing in October 2009. *Order 01* and *Order 02*.

3 On April 30, 2009, Avista filed a petition to consolidate Docket UG-060518, which addresses its pilot natural gas decoupling mechanism, with the rate case proceedings. As part of its petition, the Company asked the Commission to extend the pilot program beyond its scheduled termination date of June 30, 2009. On May 15, 2009, the Commission consolidated the decoupling issue into the general rate cases. *Order 06*. Shortly thereafter, on June 30, 2009, the Commission granted an interim extension of Avista's existing pilot decoupling mechanism but deferred a full evaluation of the program until the October 2009 evidentiary hearings. *Order 07*.

4 On August 17, 2009, Commission Staff, the Public Counsel Section of the Washington Office of Attorney General (Public Counsel) and the intervening parties filed their respective response testimonies.[1] Staff opposed a number of the Company's restating and pro forma adjustments as well as the Company's proposed

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[1] In formal proceedings, such as this, the Commission's regulatory staff participates like any other party, while the Commissioners make the decision. To assure fairness, the Commissioners, the presiding administrative law judge, and the Commissioners' policy and accounting advisors do not discuss the merits of this proceeding with the regulatory staff, or any other party, without giving notice and opportunity for all parties to participate. *See RCW 34.05.455.*

rate of return. Staff recommended smaller increases in annual revenues: $20.1 million for annual electric revenue and $281,000 for annual natural gas revenue. Public Counsel opposed many of the same adjustments criticized by Staff and also opposed Avista's proposed inclusion in rates of the costs of a power purchase agreement (PPA) to acquire the power from the existing Lancaster Generation Facility, a combined-cycle natural gas-fired power plant located near Rathdrum, Idaho.[2] Further, Public Counsel and the Industrial Customers of Northwest Utilities (ICNU) jointly opposed the Company's proposed rate of return. Public Counsel recommended a $12.8 million reduction from currently approved annual electric revenue and a $431,000 increase for annual natural gas revenue. The Energy Project's response case sought to ensure that Avista's Low Income Residential Assistance Program (LIRAP) was increased by the same percentage as any increase authorized for the Company's revenue requirement.

5 On September 4, 2009, the parties filed a Partial Settlement Stipulation; the Northwest Energy Coalition (NWEC or Coalition) did not join in the proposed settlement, but does not oppose its terms. The Partial Settlement Stipulation proposed to resolve issues relating to cost of capital and rate of return, power costs (excepting the Lancaster contracts), pro forma adjustment of power generation operation and maintenance (O&M) costs, electric rate spread and rate design, natural gas rate spread, and low-income ratepayer assistance. As a result, the Company revised downward its revenue requirement requests to $38.61 million for electric and $3.14 million for natural gas. On September 17, 2009, the settling parties filed their Joint Testimony in Support of Partial Settlement Stipulation.

6 On rebuttal, filed September 11, 2009, Avista further reduced its asserted revenue deficiencies to $37.5 million for electric and $2.8 million for natural gas, taking into account updated cost figures. Table 1 (below) summarizes the final levels of adjustment to annual revenue proposed by the three parties who put on full revenue requirement cases.

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[2] Public Counsel also opposed the inclusion in rates of agreements related to the Lancaster facility for natural gas capacity and electric transmission rights.

TABLE 1

**Proposed Total Adjustments to Annual Base Rates
Revenue Requirement Relative to Current Rates**

	As-Filed	Response	Rebuttal/Cross Answer
Electric:			
Avista	$69,800,000		$37,500,000
Staff		$20,100,000	$22,800,000
Public Counsel		($12,800,000)	$4,300,000
Natural Gas:			
Avista	$4,919,000		$2,849,000
Staff		$281,000	$568,000
Public Counsel		$431,000	$690,000

7 The Commission conducted evidentiary hearings in Olympia, Washington, on October 6-9, 2009. The parties filed simultaneous Post-Hearing Briefs on November 10, 2009.

8 **PARTY REPRESENTATIVES:** David J. Meyer, Vice President and Chief Counsel for Regulatory and Governmental Affairs, Spokane, Washington, represents Avista. Simon ffitch, Assistant Attorney General, Seattle, Washington, represents Public Counsel. Greg Trautman, Assistant Attorney General, Olympia, Washington, represents the Commission's regulatory staff (Commission Staff or Staff). S. Bradley Van Cleve and Irion Sanger, Davison Van Cleve, P.C., Portland, Oregon, represents ICNU. Chad M. Stokes and Tommy Brooks, Cable Huston Benedict Haagensen & Lloyd LLP, Portland, Oregon, represent Northwest Industrial Gas Users (NWIGU). David Johnson, Seattle, Washington, represents NWEC. Ronald Roseman, Seattle, Washington, represents The Energy Project.

9 **COMMISSION DETERMINATIONS:** The Commission suspended and set for hearing the rates Avista originally proposed. The Company, as summarized above, revised its as-filed proposal downward during the pendency of these proceedings. Accordingly, the Commission must determine fair, just, reasonable and sufficient

rates based on the record before us.[3] In this order, we evaluate Avista's final revised rate request and resolve a number of contested issues that separate the parties by several million dollars. We also resolve several important policy issues relating to the standards and guidelines for evaluating and approving pro forma adjustments and reiterate the requirements for addressing transactions with affiliated interests. We summarize our determinations in Tables 4 and 5 (below).

10 The Commission finds on the basis of the evidence presented that Avista requires rate relief and therefore determines that the Company should be authorized and required to file rates in compliance with our decisions, as summarized here and discussed in detail below. When implemented via the compliance filing we require the Company to make, the resulting rates will be fair, just, reasonable and sufficient, and neither unduly discriminatory nor preferential. Because we require Avista to rerun its AURORA power cost model based on the removal of the Lancaster contracts, we will determine the Company's exact revenue deficiency for electric service after its compliance filing.[4] We find a revenue deficiency of $557,000 for natural gas and authorize Avista to file rates to recover additional revenue in this amount. The Company's new rates will be effective no earlier than January 1, 2010. Finally, the Commission approves a continuation of Avista's decoupling mechanism, with modifications including a lower maximum deferral rate of recovery for lost margins.

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[3] RCW 80.28.020.

[4] Reviewing the evidence available to us at this time, we estimate a revenue deficiency of $12.1 million for electric.

MEMORANDUM

I. Background and Procedural History

11 On January 23, 2009, Avista filed revisions to its currently effective Tariff WN U-28, Electric Service, and revisions to its currently effective Tariff WN U-29, Natural Gas Service. The proposed tariff revisions bore an effective date of February 23, 2009. Avista proposed a general rate increase of 16.0 percent for the electric tariffs and 2.4 percent for the gas tariffs. The Commission suspended the proposed tariff revisions on February 3, 2009, consolidated the two dockets, and set the matters for hearing.

12 Avista's initial request was based on a test year ending September 30, 2008, with pro forma adjustments into 2010. The filing also included proposals for the following:

- An overall rate of return of 8.68 percent.
- A rate of return on common equity of 11.0 percent.
- A capital structure consisting of 47.51 percent equity and 52.49 percent debt.
- Inclusion of the Lancaster power purchase agreement (PPA) in electric rates, beginning on January 1, 2010.

The Company's direct testimony accompanied its filing, as required by law.

13 The Commission conducted a prehearing conference on February 24, 2009, before Administrative Law Judge Adam E. Torem. On February 27, 2009, the Commission entered Order 02, granting various petitions to intervene, authorizing formal discovery, and establishing a procedural schedule.

14 The parties prefiled extensive testimony and numerous exhibits sponsored by 36 witnesses, including 19 for Avista, 6 for Public Counsel, 8 for Staff, and 3 for the various intervenors. On September 4, 2009, all parties except NWEC filed a Partial Settlement Stipulation resolving cost of capital, rate spread, and several other issues. NWEC does not oppose the terms of this proposed settlement.

15 The Commission held separate public comment hearings in both Spokane Valley, Washington, and Spokane, Washington, on September 30, 2009, and conducted evidentiary hearings in Olympia, Washington, on October 6-9, 2009. Chairman Jeffrey D. Goltz, Commissioner Patrick J. Oshie and Commissioner Philip B. Jones were assisted at the bench by presiding Administrative Law Judge Adam E. Torem. Altogether, the record includes more than 300 hundred exhibits entered during four days of evidentiary proceedings. The transcript of these proceedings exceeds 1300 pages in length.

16 The parties filed simultaneous Post-Hearing Briefs on November 10, 2009. The Commission here enters its Final Order resolving the disputed issues, approving certain uncontested adjustments, and granting appropriate relief considering the full record of proceedings and the parties' arguments based on that record.

II. Discussion and Decisions

A. Introduction

17 The Commission has a statutory duty to determine and set rates that are fair, just, reasonable, and sufficient.[5] As set forth in more detail below in the context of some contested issues, to strike this balance between company and ratepayer interests, the Commission follows long-established and judicially recognized rate-making principles.[6] The rates must not only be reasonable to consumers, but they must be "sufficient" for the company in that they "enable the company to operate successfully, to maintain its financial integrity, to attract capital, and to compensate its investors for the risks assumed . . . ."[7]

18 Pursuant to these principles and historic Commission practice, the Commission determines appropriate levels of prudently incurred expenses the company will incur,

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[5] RCW 80.28.020.

[6] *See People's Organization for Washington Energy Resources v. Washington Utilities & Transportation Comm'n*, 104 Wn.2d 798, 807-13, 711 P.2d 319 (1985) (describing ratemaking principles and process) [Hereinafter *POWER*].

[7] *Id.* at 812, *quoting Federal Power Comm'n v. Hope Natural Gas Co.,* 320 U.S. 591, 605, 64 S.Ct. 281, 88 L.Ed. 333 (1944).

and allows recovery of those expenses. In addition, the Commission determines the company's "rate base" and determines an appropriate rate of return to be applied to that rate base to determine the authorized return. The two figures – expenses and return – constitute the company's revenue requirement which is to be recovered in rates.[8] The Washington Supreme Court explained the rate-making formula:

> In order to control aggregate revenue and set maximum rates, regulatory commissions such as the WUTC commonly use and apply the following equation:
>
> $$R = O + B(r)$$
>
> In this equation,
>
> R is the utility's allowed revenue requirements;
> O is its operating expenses;
> B is its rate base; and
> r is the rate of return allowed on its rate base.
>
> Although regulatory agencies, courts and text writers may vary these symbols and notations somewhat, this basic equation is the one which has evolved over the past century of public utility regulation in this country and is the one commonly accepted and used.[9]

19 In this case, the parties propose a settlement on a number of the issues in the rate-making equation. We first address that proposed settlement and then address the contested issues.

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[8] *POWER*, 104 Wn.2d at 807-09.

[9] *Id.* at 809.

B. Partial Settlement Stipulation

20 *Background.* On September 4, the Company filed a Partial Settlement Stipulation on behalf of all the parties that had contested electric revenue and rate design issues. The Partial Settlement Stipulation proposes resolution of the following contested issues:

- Cost of Capital, Capital Structure and Rate of Return;
- Power Costs (excepting the effect of the Lancaster Contracts);
- *Pro Forma* Adjustment of Power Generation O&M; and
- Rate Spread (electric and natural gas) and Rate Design (electric only).

In this section, we set out the regulatory requirements for our consideration of such agreements. We then summarize the parties' Partial Settlement Stipulation, which is attached to and made a part of this Order by reference (Appendix A). If any inconsistency is perceived between our summary and the Partial Settlement Stipulation, the express terms of the Partial Settlement Stipulation control.

21 WAC 480-07-750(1) states in part: "The commission will approve settlements when doing so is lawful, the settlement terms are supported by an appropriate record, and when the result is consistent with the public interest in light of all the information available to the commission." Thus, the Commission considers the individual components of the Partial Settlement Stipulation under a three-part inquiry. We ask:

- Whether any aspect of the proposal is contrary to law.
- Whether any aspect of the proposal offends public policy.
- Whether the evidence supports the proposed elements of the Settlement Agreement as a reasonable resolution of the issue(s) at hand.

22 The Commission must determine one of three possible results:

- Approve the proposed settlement without condition.
- Approve the proposed settlement subject to conditions.
- Reject the proposed settlement.

23 As discussed below, we find the Partial Settlement Stipulation terms proposed by the parties to be consistent with law and policy, and to reasonably resolve several

significant issues in this proceeding. The parties made concessions relative to their respective litigation positions to arrive at end results that are supported by the evidence in the record. When combined with the Commission's other determinations in these proceedings, the parties' compromises result in rates that are "fair, just, reasonable and sufficient," as required by law.[10]

24 *Cost of Capital, Capital Structure and Rate of Return – Electric and Natural Gas.* The settling parties proposed a resolution of all cost of capital issues, including capital structure and cost rates for common equity and debt. They agreed to a 10.2 percent return on equity (ROE),[11] with a 46.5 percent common equity ratio, and the Company's originally proposed average debt cost of 6.57 percent. Under these agreed figures, the Company will have the opportunity to earn an overall Rate of Return (ROR) of 8.25 percent, slightly higher than its currently approved ROR of 8.22 percent.

25 The agreed ROE falls within the range of recommendations from the Company, Staff, Public Counsel and ICNU.[12] Further, it is the same ROE we approved for the Company in its past two rate orders.[13] Finally, these parties support the use of the

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[10] RCW 80.28.010(1); RCW 80.28.020.

[11] Public Counsel and ICNU reserved the right to advocate for a lower ROE in the event the Commission approves decoupling or another risk reduction mechanism for the Company. *See* Joint Testimony, Exh. JT-1T at 9:15-17 and 18:3-9 (characterizing the 10.2 percent ROE as a "cap" which could be reduced if Avista's decoupling mechanism is continued). As further explained below in our determination to approve a continuation of a decoupling mechanism, we decline to modify the Company's ROE.

[12] Staff's expert witness, Mr. David Parcell, estimated a range for ROE between 9.5 to 10.5 percent. Joint Testimony, Exh. JT-1T at 16:5-11; *see also* Parcell, Exh. DP-1T at 4:9-12. Public Counsel's and ICNU's expert witness, Mr. Michael P. Gorman, estimated a range for ROE between 9.7 to 10.5 percent. Joint Testimony, Exh. JT-1T at 17:17 to 18:2; *see also* Gorman, Exh. MPG-1T at 2:3-10.

[13] *See* Dockets UE-080416 and UG-080417 (approving a settlement with an ROE of 10.2 percent) and Dockets UE-070804 and UG-070805 (approving a settlement with an ROE of 10.2 percent). However, we recognize that in this case there was substantial disagreement about the impact of the current economic recession on the ROE appropriate for setting rates. Public Counsel argued that the current economic situation should accommodate a lower ROE (Gorman, Exh. MPG-1T at 9-13), while the Company argued otherwise (Avera, Exh. WEA-1T at 7-17). Because this was

46.5 percent equity ratio as a reasonable compromise between the Company's actual year-end 2008 equity ratio of 45.4 percent and its projection of 47.51 percent by the end of 2009.[14]

26 We find that the proposed cost of capital falls within the range of outcomes supported by the evidence of record. Therefore, we conclude that the 10.2 percent ROE and resulting 8.25 percent overall ROR are reasonable and we approve this portion of the Partial Settlement Stipulation.

27 *Power Costs.* The settling parties agreed to an $11.1 million increase in the Company's currently approved revenue requirement associated with net power costs.[15] Relative to the Company's original revenue request, the settling parties agree to the following six separate but interrelated adjustments:

1) *Natural Gas Fuel Costs.* Adjust natural gas fuel costs to be $5.61 per dekatherm (at Stanfield) for the unhedged portion of 2010 power generation. This adjustment includes the actual 2010 calendar-year wholesale electric and natural gas transactions entered into through July 3, 2009. This adjustment reduces the Company's as-filed revenue requirement by $18.1 million.

2) *Hydro-filtering.* Adjust power supply expense to remove the effects of months when hydro-generation was either higher or lower by more than one standard deviation from the 50-year average for that month. This reduces the Company's as-filed revenue requirement by $729,000.

3) *Retail Load Adjustment.* Adjust rate-year system load used for calculating pro forma power expense (calendar 2010) by 3 percentage points from 5.1 percent to 2.1 percent. The effect of this adjustment is to reduce the Company's as-filed revenue requirement by $9.1 million.

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settled, we need not resolve the dispute regarding the impact of the economy on establishing appropriate ROE in this proceeding.

[14] Joint Testimony, Exh. JT-1T at 16:11-14 and 18:10-14.

[15] Partial Settlement Stipulation, Exh. B-1 at 4, and Attachment A at 1.

4) *Colstrip Availability.* The parties agree to use the Company's proposed 5-year average for the period ended December 31, 2007, to represent the equivalent availability factor for Colstrip.

5) *WNP-3 Contract.* The parties agree to use the level of WNP-3 operations and maintenance cost approved by the Commission in Cause No. U-86-99, as reflected in the Company's original filing.

6) *Kettle Falls Fuel Availability.* Adjust Kettle Falls generation to reflect a reduction in fuel availability. The effect of this adjustment is to increase the Company's as-filed revenue requirement by $383,000.

In sum, the agreed power cost adjustments reduce the Company's originally filed request in this matter by $27.5 million.[16]

28 The parties' agreement allows the Company to recover additional costs related to power supply, while recognizing the significant reduction in natural gas fuel costs.[17] We view the fuel-related adjustments as balancing the interests of the parties (and ratepayers), while considering the impacts of recent conditions in the relevant fuel markets. Further, the agreement reflects the retail load and hydro-filtering adjustments jointly proposed by Staff and ICNU.[18] We conclude that the settlement's treatment of the power cost issues enumerated above is reasonable and supported by the evidence presented. Therefore, we approve these power cost adjustments. However, to the extent the power cost modeling supporting the settlement includes the costs and benefits of the Lancaster contracts, we direct later in this Order that the power cost model be revised to produce the net power cost adjustments excluding the Lancaster contracts.

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[16] Public Counsel seeks a further adjustment to net power costs by removing 2010 expenses related to the Lancaster Power Purchase Agreement (PPA) and associated contracts. We address the Lancaster matter below, beginning at ¶ 175.

[17] Joint Testimony, Exh. JT-1T at 15:5-6.

[18] *Id.* at 16:15-22.

29 *Power Generation O&M.* The settling parties agree to reduce the Company's original filed adjustment for generating plant operation and maintenance costs by $2.4 million. The evidence of record regarding this adjustment is contained in the Company's original proposal to include these costs in rates[19] and Staff's analysis offered in support of reversing this adjustment.[20] The agreed upon adjustment is a compromise of as-filed positions supported by all parties which we therefore accept and approve.

30 *Electric Rate Spread and Rate Design.* The settling parties propose to apply an equal percentage increase to all electric service schedules for purposes of recovering the Company's revenue requirement.[21] With regard to electric rate design, the settling parties agree to the Company's initial proposal as contained in the original filing for all schedules except for Extra Large General Service Schedule 25.[22] The Extra Large General Service Schedule 25 will be altered so:

- the minimum charge will be increased from $10,000 to $11,000 per month (ten percent);
- the excess demand charge will be increased from $3.00 to $3.50 per kVa;
- the voltage discount for over 60kV will be increased to $1.00/kVa and for over 115kV to $1.20/kVa; and
- a uniform percentage increase will be applied to the first two energy block rates, and the increase to the third energy block rate will be equal to one half the percentage increase applied to the first two blocks.[23]

For residential service, the parties propose to increase the basic charge from $5.75 per month to $6.00 per month.[24]

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[19] Storro, Exh. RLS-1T at 23:16 – 24:3.

[20] LaRue, Exh. AMCL-1T at 14:1 – 15:22.

[21] Partial Settlement Stipulation, Exh. B-1 at 5.

[22] *Id.* at 5-6. Schedule 25 includes the Company's large commercial electric customers.

[23] *Id.*

[24] Partial Settlement Stipulation, Exh. B-1 at 5.

31 In accordance with the Settlement Agreement we approved in Dockets UE-070804 and UG-070805, Avista is expected to complete a new cost and load study in 2010.[25] Therefore, we agree with ICNU[26] that in this proceeding it remains appropriate to assign each class the same percentage increase. This approach preserves the status quo and allows time for parties to review and analyze the new study before embarking on a more complex shifting of costs to move the various ratepayer classes along toward parity. We also concur with Public Counsel's assessment that the 25 cent increase to the electric customer basic charge is acceptable.[27]

32 The record includes evidence sufficient to support the electric rate spread and rate design proposal made by the settling parties. Commission Staff supported a very similar approach to that adopted by the settling parties.[28] Therefore, we approve this portion of the settling parties' proposal.

33 *Natural Gas Rate Spread and Rate Design.* The settling parties also propose to apply an equal percentage increase to all natural gas service schedules, excepting Schedule 146 (Transportation), which will receive two-thirds of an equal margin increase, with the residual one-third allocated proportionately (based on margin) to the other schedules.[29] With regard to natural gas rate design, the settling parties agree to the Company's original proposal to increase the rates within Schedules 111 and 112 to maintain the existing break-even usage level between Schedules 101 and 111, aiming to minimize future customer schedule shifting. Although the Partial Settlement Stipulation does not resolve Schedule 101 gas rate design issues (including customer charges), the settling parties agree that design of rates under Schedule 101 will not be

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[25] Knox, Exh. TLK-1T at 14:4 – 15:2.

[26] Joint Testimony, Exh. JT-1T at 19:6-15. Public Counsel's expert witness, Glenn A. Watkins, also concurred with the across-the-board equal percentage increase in base rates by class. *Id.* at 21:18 – 22:2; *see also* Watkins, Exh. GAW-1T at 3-8.

[27] Joint Testimony, Exh. JT-1T at 22:3-7; *see also* Watkins, Exh. GAW-1T at 9.

[28] Joint Testimony, Exh. JT-1T at 17:3-4.

[29] Partial Settlement Stipulation, Exh. B-1 at 6.

conditioned or dependent upon the rates in Schedules 111 and 112.[30] Finally, the settling parties agree that Schedule 146 rates (including the customer charge) will be increased on an equal percentage basis.[31]

34 The Partial Settlement Stipulation provides consensus around nearly all issues regarding rate spread and rate design; due to the disputes over the fate of Avista's decoupling mechanism, only the natural gas basic charge issue could not be resolved.[32] We concur with NWIGU that the proposed spread of the gas rate increase was accomplished in a manner consistent with the available cost of service analyses.[33] In addition, Public Counsel and the Energy Project confirm that the proposal follows the status quo on rate spread established in the Company's most recent rate case.[34]

35 We find that the record contains sufficient evidence to support the natural gas rate spread and rate design recommendations of the settling parties. Therefore, we also approve this portion of the settling parties' proposal.

36 *Low-Income Ratepayer Assistance Program (LIRAP) – Electric and Natural Gas.* The Partial Settlement Stipulation also addresses the low income bill assistance funding issues through an agreement to increase rates for the Low Income Ratepayer Assistance Program (LIRAP) portion of the tariff riders (Schedules 91 and 191) by the *greater* of the overall percentage increase in base revenue approved for each schedule or, for electric, 9 percent, and for natural gas, 1.75 percent.[35]

37 Commission Staff endorsed the augmented LIRAP funding, noting that while the electric increase is a larger percentage of revenue than comparable company programs, the natural gas increase is within the range of those adopted by other

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[30] *Id.* at 6-7.

[31] *Id.*

[32] Joint Testimony, Exh. JT-1T at 15:7-11.

[33] *Id.* at 20:18-21; *see also* Schoenbeck, Exh. DWS-5T at 3-8.

[34] Joint Testimony, Exh. JT-1T at 21:18 – 22:2.

[35] Partial Settlement Stipulation, Exh. B-1 at 7.

natural gas companies.[36] We agree with Public Counsel and the Energy Project that establishing an increase for LIRAP funding guaranteed to keep pace with or possibly exceed any approved rate increase is in the public interest. The current economic recession has placed increased pressure on low income households and resulted in the creation of more low income households. Though even this increased level of LIRAP funding may not be adequate to meet all the needs of all low income households, the proposed approach to LIRAP funding is consistent with RCW 80.28.068 and will have minimal impact on the bulk of other ratepayers.[37]

38 This portion of the Partial Settlement Stipulation advances established public policy goals in Washington, and the record contains sufficient supporting evidence. Therefore, we approve the settling parties' proposal to increase LIRAP funding.

39 *Overall Approval of Partial Settlement Stipulation.* In sum, the Partial Settlement Stipulation's provisions reach agreement on an overall rate of return within the ranges advocated by the parties, make appropriate adjustments to the Company's power costs, and adopt a common-sense approach to rate spread and rate design. The settlement also ensures that funding for Avista's LIRAP program keeps pace with any rate increases we approve for the Company. The compromises reached by the settling parties comply with the law, are consistent with state policy and are in the public interest. Therefore, we adopt the Partial Settlement Stipulation in its entirety.

C. Pro Forma Adjustments

1. General Principles of Utility Rate Setting Applied to Pro Forma Adjustments

40 As part of its obligation to determine rates that are fair, just, reasonable, and sufficient, pursuant to RCW 80.28.020, and order them into effect prospectively, the Commission must base its decision on the record provided by the Company and the other parties.

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[36] Joint Testimony, Exh. JT-1T at 17:9-15.

[37] *Id.* at 22:17 – 23:6.

41 The Commission's long-established and well-understood ratemaking practice requires companies filing for revised rates to start with an historical test year. There is a fundamental reason for this starting point: costs, revenues, loads, and all other pertinent factors are known and can be measured with a high degree of certainty because they have, in fact, occurred. The practical value of the historical test year is that the cost, revenue and plant data are available for audit, and the test year captures the complex relationships among the various aspects of utility costs, revenue, load, and other factors over a uniform period of time.

42 The Commission recognizes that the test year is a snapshot in time. The typical test year is the twelve month period preceding the rate filing, ended as of the most recent auditable results of operations.[38] A utility, however, continues to operate, incur costs (including capital additions), achieve savings, and receive revenues during the pendency of its rate review subsequent to the test year that would carry over into the year in which the rates would be effective (known as the "rate year") and beyond. The theory, well supported by ratemaking theory and past commission practice,[39] is that once the relationship is set, it will continue to provide appropriate income to the company in the future. If the utility hooks up new customers, the revenues and expenses will increase in the same proportion as existed in the test tear. If new facilities are put into service to serve those customers, then the resulting revenues would not only cover the company's added expenses, but also effectively provide a return on that new investment.

43 However, our past decisions, and our rules, recognize that there are some expenses or investments that do not take place in the test year that, nevertheless, should be included in the rate-making formula. Thus, subject to important conditions, a company's rate filing may include restating and pro forma adjustments.[40] These are

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[38] The test year is a period of company operations for which the Commission conducts a careful audit and review prior to authorizing any change in rates. *See* 1 Leonard S. Goodman, *The Process of Ratemaking* 141 (1998).

[39] *See* Charles F. Phillips, Jr., *The Regulation of Public Utilities* 196 (1993).

[40] WAC 480-07-510 (3)(e)(ii) and (iii) provide as follows:

> (ii) "Restating actual adjustments" adjust the booked operating results for any defects or infirmities in actual recorded results that can distort test period earnings. Restating actual adjustments are also used to adjust from an as-recorded basis to a

allowed to revise or update expenses, revenues, and rate base so long as there is a mechanism ensuring, and evidence establishing, that these adjustments do not disturb test year relationships.

44 In order to ensure that the Commission has proper information on which to base test year expenses and investments, and any adjustments to those expenses and investments, the Commission has rules that require certain threshold information that all parties must include in their rate filings. With regard to accounting adjustments, work papers must

> contain a detailed portrayal of restating actual and pro forma adjustments that the company uses to support its filing or that another party uses to support its litigation position, specifying all relevant assumptions, and including specific references to charts of accounts, financial reports, studies, and all similar records relied on by the company in preparing its filing, and by all parties in preparing their testimony and exhibits. All work papers must include support for, and calculations showing, the derivation of each input number used in the detailed portrayal and for each subsequent level of detail. The derivation of all interstate and multiservice allocation factors must be provided in the work papers.[41]

To be approved, a pro forma adjustment to test year operations must comport with the three key principles expressed above, two of which are embodied in the Commission's regulations and the third in statute.

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basis that is acceptable for rate making. Examples of restating actual adjustments are adjustments to remove prior period amounts, to eliminate below-the-line items that were recorded as operating expenses in error, to adjust from book estimates to actual amounts, and to eliminate or to normalize extraordinary items recorded during the test period.

(iii) "Pro forma adjustments" give effect for the test period to all known and measurable changes that are not offset by other factors. The work papers must identify dollar values and underlying reasons for each proposed pro forma adjustment.

[41] WAC 480-07-510(3)(e).

45 First, the adjustment must be known and measurable. The known and measurable concept requires that an event that causes a change in revenue, expense or rate base must be *known* to have occurred during or after the historical 12 months of actual results of operations.[42] It must also be demonstrated (*i.e.*, *known)* that the effect of the event will be in place during the 12-month period when rates will likely be in effect.[43] The actual amount of the change must be *measurable.* This means the amount cannot be an estimate, a projection, the product of a budget forecast, or some similar exercise of judgment—even informed judgment—concerning future revenue, expense or rate base. Costs that are documented by actual expenditure, invoice, contract, or other specific obligation usually meet this test. Costs that are the product of forecasts, projections, or budgets generally will not qualify. There are exceptions, and we will discuss those below.

46 Second, for rate base, and for expense or revenue items, pro forma adjustments must be matched with offsetting factors. Offsetting factors, as the term suggests, diminish the impact of the known and measurable event. A mismatch would be created if offsetting factors are not taken into account.[44] That is, the known and measurable change will be overstated or understated, distorting the test year relationships among revenues, expenses, and rate base.

47 The less certainty with which actual utility costs and offsetting factors are known and measurable, the greater is the risk that an adjustment would disturb test year relationships and the less appropriate is the pro forma adjustment. The Commission must assess the certainty with which costs and offsetting factors are known when it balances the competing pressure to change test year values to reflect newer information with the objective of preserving the integrity of test year relationships.[45]

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[42] This is also known as the "test year," "test period" or "historical test year."

[43] This is also known as the "rate year."

[44] For example, a pro forma adjustment that incorporates the addition of new plant in service would be offset by an adjustment to test year O & M expenditures that reflect the aged condition of the plant replaced.

[45] The farther a proposed adjustment is removed in time from the test year, and the less time that supporting evidence is available for examination, discovery, and testing by our staff and other

48 Third, if the pro forma adjustment is to add new plant, pursuant to statute it must be shown that the new plant will be used and useful to serve Washington customers.[46] With very limited exceptions the plant must be in service by no later than the end of the rate proceeding if it is to be allowed in rate base.[47] Typically, this means the plant will be in service before the suspension date, which generally marks the beginning of the "rate year."

49 Certain rate-making mechanisms have been developed to allow prospective changes for inclusion in rates by "building in" adjustments that ensure that the matching principle is maintained. The power cost models used to measure net power costs under average and otherwise expected conditions of load, weather, and market conditions are such a mechanism, allowing for exception to strict application of the above three principles. Power cost models yield expected net power costs by rigorously matching costs and revenues. While these models employ assumptions, estimates, and forecasts as inputs, the modeled results are generally acceptable if the model inputs are reasonable and the modeling is comparable in analytical rigor to what is brought to bear in making normalizing adjustments.

50 The production plant cost adjustment factor (known sometimes in this rate case as a "production property adjustment") is another rate making mechanism that preserves test year relationships between costs and revenues. It does so in appropriate

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parties, the greater is the Company's burden to demonstrate that the requirements guiding adjustment to test year data have been met.

[46] The Commission also examines whether the new plant has been prudently built or acquired. To answer the prudency question, the Commission examines many factors, including whether the costs asserted are reasonable compared to other alternatives the Company considered at the time the decision to build or acquire was made. The Company must support its decision with sufficient evidence. *See UTC v. Puget Sound Power & Light Company*, Docket Nos. UE-920433, UE-920499, & UE-921262 (*consolidated*), 11th Supplemental Order, at 18-24 (Sept. 21, 1993) and 19th Supplemental Order (Sept. 27, 1994).

[47] In accordance with RCW 80.04.250, the Commission is empowered "to ascertain and determine the fair value for rate making purposes of the property of any public service company used and useful for service in this state and shall exercise such power whenever it shall deem such valuation or determination necessary or proper under any of the provisions of this title. In determining what property is used and useful for providing electric, gas, or water service, the commission may include the reasonable costs of construction work in progress to the extent that the commission finds that inclusion is in the public interest."

circumstances by adjusting rate year costs to match test-year loads. We emphasize that pro forma adjustments to costs that are not included in such well-established mechanisms must be accompanied by thorough and specific analyses of their offsetting factors.

51 As articulated below, in this case, for a number of proposed pro forma adjustments, Avista fell short of meeting its obligations under the relevant Commission rules. Rather than present evidence of costs for new capital additions or for new expenses, Avista provided estimates. Also, rather than carefully analyzing savings or other offsetting factors that should be included in any pro forma analysis, the Company sometimes ignored such factors or addressed them in a minimal fashion. Accordingly, as detailed below, we did not accept a number of the Company's proposed pro forma adjustments.

52 In each instance, our decision does not preclude recovery of the cost of capital additions in a future proceeding where new plant additions are shown to be in service and the costs and offsetting benefits are reflected in test year data or are thoroughly analyzed in support of a pro forma adjustment.

2. Uncontested Adjustments to Test Year Results of Operations

53 The parties agree on a number of restating and pro forma adjustments to the Company's results of operations for the test year. We summarize these in Table 2A for electric and Table 2B for natural gas on the following pages.

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TABLE 2A
Uncontested Restating & Pro Forma Adjustments – Electric ($000)

	NOI	**Rate Base**
Test Year Results of Operations	**68,538**	**1,053,828**
UNCONTESTED ADJUSTMENTS		
Deferred FIT Rate Base	-	(142,713)
Deferred Gain on Office Building	-	(126)
Colstrip 3 AFUDC	202	(1,956)
Colstrip Common AFUDC	-	436
Kettle Falls Disallowance	(56)	(854)
Customer Advances	-	(231)
Depreciation True-up	39	-
Settlement Exchange Power	-	18,422
Eliminate B&O Tax	(22)	-
Uncollectable Expense	70	-
Regulatory Expense	(52)	-
FIT	(1,751)	-
Eliminate WA Power Cost Deferral	(8,844)	-
Nez Perce Settlement Adj.	(6)	-
Eliminate A&R Expense	335	-
Office Space Charges to Subsidiary	5	-
Restate Excise Taxes	(20)	-
Net Gain/Losses	79	-
Revenue Normalization	23,394	-
Miscellaneous Restating (1)	113	-
Restate Debt Interest	697	-
Transmission Rev/Exp	(51)	-
Spokane River Relicense	(2,549)	22,530
Montana Lease	(2,285)	2,859
O&M Plant Expense	-	-
Employee Benefits	(2,920)	
Colstrip Mercury(2)	(630)	
Clark Fork PM&E	(426)	-
Total Uncontested Adjustments	**5,322**	**(101,633)**

(1) Includes Company's correction to transfer Edison Electric Institute dues from natural gas to electric books per EMA-8(11).

(2) Andrews, TR. 532:7-25, confirms agreement on this adjustment.

TABLE 2B
Uncontested Restating & Pro Forma Adjustments – Natural Gas ($000)

	NOI	Rate Base
Per Books	**12,004**	**178,717**
UNCONTESTED ADJUSTMENTS		
Deferred FIT Rate Base	-	(27,674)
Deferred Gain on Office Building	-	(42)
Gas Inventory	-	11,064
Weatherization & DSM	-	-
Customer Advances	-	(52)
Depreciation True-up	54	-
Revenue Normalization	3,648	-
Eliminate B&O Tax	(4)	-
Uncollectable Expense	93	-
Regulatory Expense	(9)	-
FIT	(10)	-
Net Gain/Losses	8	-
Eliminate A&R Expense	55	-
Office Space Charges to Subsidiary	1	-
Restate Excise Taxes	(51)	-
Miscellaneous Restating (1)	97	-
Restate Debt Interest	80	-
Employee Benefits	(771)	
AGA Dues(2)	-	-
JP Storage	(1,778)	8,922
Total Uncontested Adjustments	**1,413**	**(7,782)**

(1) Includes Company's correction to transfer Edison Electric Institute dues from natural gas to electric books per EMA-8(11).

(2) Adjustment to AGA Dues is included in adjustment to miscellaneous restatements per EMA-8(11).

54 We accept these uncontested adjustments as appropriate without the necessity for detailed discussion. However, we must now review each of the contested adjustments, considering in detail the record evidence and the key principles previously described.

3. Contested Pro Forma Adjustments to Rate Base

a. Introduction

55 The rate base represents the net book value of assets which are used and useful in providing utility service to ratepayers within our state. Typically, it is determined for the test year (and therefore for rate-making purposes) by determining the average net book value for each month of the test year and then averaging those figures. This "average of monthly averages" method has long been the method of determining rate base by this commission.[48]

b. Pro Forma Rate Base – Capital Additions – Electric

56 *Positions of the Parties.* Avista proposes "to include in retail rates the costs associated with utility plant that is in service, and will be used to provide energy service to our customers during the 2010 pro forma rate year." According to the Company, its proposal is "consistent with prior ratemaking practice in the state of Washington."[49]

57 Explaining the factors driving its need to make new plant investments, Avista points to the need to strengthen the Company's transmission and distribution systems, aging infrastructure, physical degradation, and to meet the costs of municipal compliance including street relocations. The Company asserts that these necessary plant investments are increasingly expensive and exceed depreciation revenue due to

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[48] *See UTC v. Washington Water Power*, Cause No. U-76-8, Second Supplemental Order Rejecting Revisions to Tariff WN U-23 But Authorizing Refiling Under Conditions Stated, at 6-7 (Dec. 23, 1976) (stating Commission opinion "that an historical test year properly restated and proformed, using an average-of-monthly-averages in calculating rate base continues to be a reliable and consistent basis for establishing rates in electric and other utility cases."); *see also UTC v. Washington Water Power*, Cause No. U-82-10 & U-82-11*(consolidated)*, Second Supplemental Order, at 9 (Dec. 29, 1982) (noting average-of-monthly-averages as historically preferred method for determining proper rate base); *see also UTC v. Puget Sound Power and Light*, Cause No. 85-53, Second Supplemental Order, at 27-28 (May 16, 1986) (adopting average-of-monthly-averages approach to depreciation expense adjustment as best means to properly match revenues and expenses).

[49] DeFelice, Exh. DBD-1T at 2:7-11.

increased cost of construction materials in the range of 55 percent to 170 percent since 2003.[50]

58 The Company proposes three adjustments to electric rate base to incorporate capital additions made, or planned to be made, subsequent to the September 30, 2008, end of the test-year:[51]

- The Company's first contested adjustment would add $21.4 million to net rate base and reduce net operating income (NOI) by $473,000 for capital projects completed during the last three months of calendar year 2008 and annualizes plant-in service balances to a December 31, 2008, end-of-period balance.[52]

- The Company's second contested adjustment would add $22.9 million to net rate base and reduce NOI by $2.9 million for plant additions and expenses for projects completed or planned to be completed in 2009 and annualizes plant-in service balances to a December 31, 2009, end-of-period balance.[53]

- The Company's third contested adjustment would add $5.4 million to net rate base and reduce NOI by $156,000 for plant additions planned to be completed on unit 3 of the Noxon generating station in early 2010. The Noxon plant is a hydroelectric generating station located on the Clark Fork River in western Montana. According to the Company, the cost of the new turbine and mechanical overhaul should be included in the production rate base because they are scheduled to be completed by March 2010 and have been included in the power cost dispatch model used to calculate pro forma net power costs.[54]

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[50] *Id.* at 6:18-9:13.

[51] These adjustments are designated in the Company's testimony as PF-6, PF-7, and PF-8.

[52] Andrews, Exh. EMA-6 at 10 (column PF-6). "End-of-period" balance denotes that account totals reflect the actual balance in December, as opposed to an average balance over the 12 month period ending in December.

[53] *Id.* at 10 (column PF-7).

[54] Andrews, Exh. EMA-1T at 26:1-7.

In combination, the Company's 2008 and 2009 adjustments (first two bullets above) reflect some 230 individual projects categorized as electric generation, electric transmission, electric distribution, general plant and equipment, vehicles and technology systems.[55] Table 3 shows that the total of all three adjustments proposed by the Company is an increase to net rate base of $49,767,000 and decrease to NOI of $3,535,000.[56]

59 Staff opposes the first two of these as improper pro forma adjustments, citing to the Commission rule governing pro forma adjustments that requires such adjustments to be "known and measurable" and "not offset by other factors."[57] Staff says the Company's proposed adjustments violate the matching principle of ratemaking because they simply "provide for a wholesale inclusion of <u>all</u> plant in service . . . [and do] not address the corresponding changes in customer count, expenses, and revenues."[58] In addition, Staff objects to the Company's proposal to depart from average-of-monthly-averages rate base and to instead measure rate base at a point in time three months after the close of the test year.[59]

60 Staff notes that in some limited instances the Commission has allowed out-of-period expenses and plant additions to be included in rates, but these instances have been narrowly justified.[60] Considering these past decisions, Staff proposes an alternative adjustment to include some out-of-period 2008 and 2009 expenses and plant

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[55] A description of the projects can be found at: DeFelice, Exh. DBD-1T at 10:16 – 16:15, and Kermode, Exh. DPK-1T at 28:12-15.

[56] Net operating income is the income after tax that is available to the utility for return on invested capital. Net operating income and revenue requirement move in opposite directions. An adjustment that reflects a decrease to net operating income produces an increase in necessary revenue requirement.

[57] Parvinen, Exh. MPP-1T at 4:17-18.

[58] Kermode, Exh. DPK-1T at 32:12-18 (emphasis in original).

[59] *Id.* at 31:21-32.

[60] Staff points to the Coyote Springs generating plant and Noxon Dam upgrades as examples allowed because of materiality of the resource and inclusion of the projects in the power cost model. Staff also cites certain transmission investment undertaken to improve reliability. Parvinen, Exh. MPP-1T at 9:10-20.

investments.[61] Staff would limit the proposed adjustments to those expenses and costs that are incurred, in service, and auditable by June 30, 2009, and:

- Required by laws, regulations, or directives from regulatory bodies, or
- Transmission investments related to reliability, or
- Generating plant investment and expenses that are included in the power cost calculation and that are adjusted to match the test-year loads by the production property adjustment.

Staff identifies projects originally included in the Company's 2008 and 2009 adjustments[62] that meet the criteria above and adjusts the plant amounts to the 2010 rate year average-of-monthly-averages rate base balances, including related depreciation and deferred taxes.[63] The result of Staff's adjustment for 2008 and 2009 capital additions is to increase net rate base by $21,252,000, and decrease NOI by $599,000.[64]

61 Public Counsel shares Staff's view that the Company's proposed adjustments "violate the ratemaking principle of matching revenues, expenses, and capital costs."[65] Public Counsel recommends that any adjustment to address 2008 and 2009 additions be limited to production plant that is reflected in power supply modeling. According to Public Counsel, the power supply model captures the costs and benefits of new power resources.[66] Public Counsel recommends an adjustment to increase net electric rate base by $3,039,000 and decrease NOI by $39,000.

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[61] *Id.* at 36:4-38:3.

[62] Note that the Staff removes the Noxon 1 generator upgrade originally included in the Company's PF-7 (2009) adjustment and includes it instead in Staff's PF-8 (2010) adjustment.

[63] Kermode, Exh. DPK-1T at 38:21-23 and Exh. B-10.

[64] Exh. DPK-2 at 9 (column PF-7). These figures and all others representing the level of adjustments proposed by all parties in this proceeding are relative to the Company's test period of operations (i.e., relative to "per books").

[65] Larkin, Exh. HL-1T at 14:1-10.

[66] *Id.* at 14:12-23.

62 The Company counters that Commission precedent treats many costs as known and measurable for purposes of pro forma adjustment even though they are estimates and not precisely known. It cites examples including modeled power costs, estimated generation for PURPA projects, average injuries and damages, average transmission wheeling revenues, and the unopposed inclusion of the Noxon No. 3 upgrade costs in this proceeding.[67] For specific precedent, the Company points to a 2002 order of the Commission in a water case that describes pro forma adjustments as those that "will occur prospectively to best estimate the relationship between the Company's costs and revenues."[68] According to the Company, its actual capital program expenditures have comported closely with planned expenditures for 2005 through 2008.[69]

63 The Company says that Staff's proposal to include only a subset of its 2008 and 2009 rate base additions by using a cut-off date of June 30, 2009, would preclude it from including $14.2 million of investments in rate base and preclude it from recovering $6.5 million of related annual revenue even though "ratepayers will receive the benefit of these assets that are used and useful at December 31, 2009, for the entire 2010 rate year."[70]

64 Without abandoning its preferred proposal, the Company offers an alternative approach based generally on Staff's proposal. Avista would modify Staff's method in two ways. First, it would include all costs through the end of 2009 associated with the subset of projects Staff identifies. Second, the Company would add to Staff's set of projects some additional projects that were completed and in service by the end of July 2009. These two modifications add $33.8 million of net rate base to Staff's proposed $21.2 million.[71] When compared to its original proposal of $11.3 million,

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[67] Norwood, Exh. KON-1T at 8:8 – 11:4. We note that these examples generally involve normalizing the test year level of costs based on an average of known historical costs.

[68] *Id.* at 11:7-19, *citing UTC v. Rainier View Water Company, Inc.*, Docket UW-010877, Sixth Supplemental Order, Final Order Rejecting Tariff Filing; Ordering Refiling, ¶ 29 (July 12, 2002) [hereinafter *Rainier View Water Order*].

[69] *Id.* at 12:9-23.

[70] DeFelice, Exh. DBD-4T at 4:16-5:2.

[71] *Id.* at 11:18 – 15:20.

Avista's alternative proposal yields a combined revenue requirement of $11.4 million for all three adjustments.

65 The Company contends that Public Counsel's recommendations remove from rate base $41.3 million for assets that are used and useful by December 31, 2009, with a consequent reduction in revenue requirement of $10.8 million.[72] Noting that Public Counsel's recommendation allows generating assets to be included in pro forma rate base, the Company contends that Public Counsel's calculation is nonetheless faulty and not reliable because it creates a mismatch between net plant additions and total plant depreciation.[73]

66 Both Staff and Public Counsel generally agree that an adjustment to include the cost of the Noxon No. 3 turbine upgrade is appropriate. For its part, Staff testifies that it believes the project will be completed on time, is prudent and will be used and useful in the rate year.[74] Staff modifies the Company's 2010 Noxon No. 3 adjustment to also include the investment and expense related to the Noxon No. 1 turbine. Staff explains that the Noxon No. 1 upgrades were completed in April 2009 and plant amounts had originally been included in the Company's adjusted 2009 capital additions. According to Staff, both the Noxon No. 1 and Noxon No. 3 projects were included in the power cost dispatch model and are therefore appropriate to include in the rate year rate base that will be adjusted to test-period loads with the production property adjustment.[75] Staff further adjusts the Noxon No. 3 plant amounts to reflect that the facility will be in service for only 9 months of the rate year.[76]

67 The Company objects to Staff's recommendation to limit the Noxon No. 3 costs to remove 25 percent of the total, arguing that 100 percent of the benefits of the upgrade are included in the power cost model. Staff disagrees, contending that the power cost

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[72] *Id.* at 10:10-20.

[73] *Id.* at 8:17 – 9:18.

[74] Kermode, Exh. DPK-1T at 40:2-16.

[75] *Id.* at 40:8-16.

[76] *Id.* at 40:14-16.

model's inclusion of the full year of Noxon No. 3 operations does not determine what cost-recovery should be allowed.[77]

68 The following table summarizes the final pro forma adjustments for electric capital additions proposed by the Company, Staff, and Public Counsel.

Table 3. Comparison of Electric Plant Addition Adjustments $(000)

	Company[78]			Staff[79]			Public Counsel[80]		
	RB	NOI	RR	RB	NOI	RR	RB	NOI	RR
2008	21,445	(473)	3,605	0	0	0	2,254	(10)	315
2009	22,936	(2,906)	7,715	21,252	(599)	3,782	785	(29)	151
2010	5,386	(156)	965	14,592	(434)	2,633	5,386	(156)	965
TOTAL	49,767	(3,535)	12,285	35,844	(1,033)	6,415	8.425	(195)	1,431

Note – Revenue Requirement (RR) is calculated at settlement-proposed return of 8.25 percent and revenue conversion factor of .621953.[81]

69 *Commission Decision.* We have previously discussed and emphasized the important principles governing pro forma adjustments. The post-test-year capital addition adjustments the Company and parties propose are adjustments to rate base accounts and related expenses and must comport with all three of the important principles guiding the use of pro forma adjustments. Our analysis of the evidence and arguments regarding electric plant additions leads us to conclude that, of the various approaches, Staff's adjustment is most appropriate and consistent with these guiding principles.

70 Staff's adjustment allows recovery for plant investments made subsequent to the end of the test year so long as they are known to be completed and in service. Staff

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77 Kermode, TR. 739:12 – 740:16.

78 Andrews, EMA-6 at 10.

79 Kermode, Exh. DPK-2 at 9.

80 Exh. B-5, Electric Results of Operations, Tab A-1 Columns AM, AN and AO.

81 The revenue conversion factor translates net operating income (which is after tax) to revenue requirement (which includes income tax and other revenue sensitive taxes).

concludes that, based on careful auditing and analysis, those projects that it could confirm are in service and unlikely to have offsetting factors are appropriate to include in a pro forma adjustment. Staff's adjustment strikes a fair balance preserving the integrity of the test year, while at the same time allowing for recovery of significant capital expenditures that have occurred subsequent to September 30, 2008, the end of the test year.

71 First, Staff is correct to focus on audited results to ensure that the costs it proposes to include in rates comply with both the known and measurable principle and the used and useful principle.[82] Budgeted figures representing the Company's projected and planned costs for capital programs may prove to be inaccurate. While we do not question the rigor of the Company's management and planning processes, planned expenditures are not certain expenditures. For costs of new plant to be recovered in customer rates, the investment must have indeed occurred and the new facilities must be providing service to customers. As required by statute, the facilities must be "used and useful." Staff's adjustment includes those projects documented to be actually completed and put in service in the last quarter of 2008 and the first half of calendar year 2009.

72 Second, when adjustments are made to rate base outside of the test year, Staff is correct to be concerned about potential injury to the matching principle. Staff is correct to note that, while not perfect protection against mismatches caused by out-of-period adjustments, the operation of the production property adjustment will reasonably accomplish matching of its proposed increases to rate year production plant and related expenses to test year circumstances.

73 The Company's initial proposed adjustments and its alternative adjustments both suffer from the same related flaws: they include costs that are not shown, on this record, to be known and they also include projects that are not supported, on this record, to be in service.

74 The Company's assertions that its pro forma adjustments to electric rate base are consistent with Commission practice miss the mark. It points to two Commission

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[82] By auditing such costs, Staff also determines whether these costs have been prudently incurred.

orders for the proposition that adjustments to test year data must necessarily include "estimates." It cites our order in Docket UW-010877, and excerpts the following quote:[83]

> These adjustments are . . . 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)

The Company stretches the meaning of our sentence. The sentence means that once an event is determined to be known and measurable, it can then be used to best estimate the relationship between revenues and costs. The sentence does not stand for the proposition that all estimates of costs satisfy the known and measurable criteria.

75 The Company also points to our order in Docket U-85-36 for the proposition that all plant that is used and useful to serve customers during the rate year must be included in rates in order for rates to be "just, reasonable and sufficient."[84] Our order stated:

> . . . the rate base shown on the books is adjusted to take into account known and measurable changes which will occur during the period rates will be in effect. Such pro forma adjustments correct what would otherwise cause a miscalculation of the value of property that is used and useful for service.

Our statement made in 1985 remains correct in 2009, but it does not mean that any capital projected to be completed and serving customers qualifies as a known and measurable change, regardless of whether its actual costs are known or its actual completion and in service status can be confirmed.

76 In addition to these flaws, the Company's initial proposal relies on a significant departure from the standard measurement of rate base. Except in rare circumstances, rate base is measured as an average over the test year. The Company proposes an

[83] Norwood, Exh. KON-1T at 11:7-19 citing *Rainier View Water Order*, ¶ 29.

[84] DeFelice, Exh. DBD-4T at 3:3-7, citing *UTC v. Washington Water Power Company,* Cause No. U-85-36, Third Supplemental Order at 29-30 (April 4, 1986) [hereinafter *1986 Washington Water Power Order*].

end-of-period measurement of rate base calculated at a point in time three months *after* the end of the test year. While we could consider departing from the conventional method for measuring rate base if presented with good justification and additional steps to conform other test period data to the end-of-period point in time, we are not persuaded on this record that the significant departure the Company proposes is justified.[85] We share Staff's concern that the Company's method would disrupt test period matching of rate base with all other costs, revenues and cost of service components. Consequently, we reject the Company's initial adjustments as flawed in method.

77 The Company characterizes its alternative proposal as merely an extension of the Staff's adjustment. This characterization misses the point: the heart of Staff's adjustment is based on audited and verified information. The Company's alternative proposal includes projects planned to be completed in the second half of 2009 that are not demonstrated on this record to be in service and for which costs have not been audited and confirmed.

78 We recognize that the Company's capital investment continued beyond June 30, 2009, the date when Staff completed its audit, and that new plant not included in Staff's proposed adjustment may be in service during the rate year. But this fact is not sufficient to override the requirement that rates be set based on actual costs and that adjustments to test period cost data must comport with the regulatory requirements governing pro forma adjustments. The Company's proposal to include <u>all</u> planned 2009 capital additions is tantamount to requiring either a continuous audit during the pendency of a rate proceeding or acceptance of budgeted or forecast data as known and measurable. Staff correctly points out that for it to verify that costs are sufficiently documented and appropriate to include in rates, the dictates of practicality require its audit must conclude at some point in time before the conclusion of the rate review.

79 Public Counsel's proposed adjustments allow for no pro forma additions to rate base unless the project is included in the power cost model. This allows for no adjustments for transmission investment or other non-power-generating plant outside the test year even if it is possible to audit and confirm that projects are completed and in service

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[85] *See*, *infra*, n.48.

subsequent to the test year. We find this approach to be unnecessarily rigid. It fails to recognize the practical fact that capital investment is not confined to the test year and that rate regulation can and should have the flexibility to include out-of-period costs, so long as the important principles guiding pro forma adjustments are not violated.

80 With regard to the Noxon No. 3 upgrade, we also agree with Staff that it is appropriate to include the upgrade costs and related expenses in the rates we approve in this proceeding. Staff's adjustment to net rate base appropriately reflects that the Noxon No. 3 upgrade will be in service for only 9 months of the rate year.

81 The Noxon No. 3 adjustment is notable and unusual because, as all the parties agree, the project upgrade will not be completed until March of 2010. All parties also agree that the project costs can be included in rates in this proceeding because they are sufficiently well established and certain that the project can be included in the power cost model that yields net power costs for the rate year. By approving the Staff's recommendation, we are knowingly making an exception to strict application of the principles guiding pro forma adjustments. The Noxon No. 3 upgrade is not yet in service. The agreement among all parties that the Noxon No. 3 costs are appropriate to include, together with the importance of the project and Staff's testimony that the plant will be completed on time and is a prudent project, allows us to make an exception in this limited case and in these circumstances. Our decision here should not be taken as precedent for other capital additions that present different facts and circumstances.

82 Based on the foregoing analysis and discussion, we find appropriate an adjustment to increase net electric rate base by $35,844,000 and decrease associated NOI by $1,033,000.

c. Pro Forma Rate Base – Capital Additions – Natural Gas

83 *Positions of the Parties.* The Company proposes two pro forma adjustments to natural gas rate base. The Company's first adjustment parallels its proposed adjustment to electric rate base. It adds capital projects for the final calendar quarter of 2008 and calculates net rate base as end-of-period rather than average-of-monthly-averages. The Company uses end of calendar year 2008 as the point of measurement for its end-of-period net rate base.[86] By this adjustment, it proposes to increase net rate base by $1,234,000, increase NOI by $294,000 and *decrease* revenue requirement by $309,000.[87]

84 The Company's second adjustment also parallels its proposed adjustment to electric rate base to include all capital projects budgeted for calendar year 2009.[88] The Company uses end of calendar year 2009 as the point of measurement for its end-of-period net rate base. By this adjustment, the Company proposes to increase natural gas net rate base by $6,094,000, decrease NOI by $596,000, and *increase* revenue requirement by $1,766,000.[89]

85 The combined effect of these two adjustments to plant accounts and related expenses is to increase rate base by $7,328,000, decrease NOI by $302,000, and increase revenue requirement by $1,457,000.

86 The Company's rationale for these adjustments is the same as its rationale for the proposed capital addition adjustments to electric rate base. It asserts that its

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[86] DeFelice, Exh. DBD-1T at 19:1 – 22:11.

[87] Andrews, Exh. EMA-1T at 46:1-8.

[88] In combination, the 2008 and 2009 projects at issue include enhancements to the Jackson Prairie gas storage facility and projects to enhance or replace various components of the natural gas distribution system. DeFelice, Exh. DBD-1T at 16:17 – 17:35.

[89] Andrews, Exh. EMA-1T at 46:9-19.

adjustments are necessary to reflect plant investment that will be in service providing benefit to customers during the rate year.[90]

87 Staff and Public Counsel object to these adjustments as improper pro forma adjustments that are not known and measurable, are not shown to be in service and used and useful, and violate the matching principle. Staff also objects to the Company's end-of-period method for measuring rate base accounts.[91] Staff and Public Counsel recommend that the Commission reject both the Company's 2008 and 2009 adjustments.[92]

88 The Company objects that Staff's and Public Counsel's recommendations will deprive it of $7.3 million of rate base and $1.5 million in annual revenue for projects that it asserts are known and measurable, that have minimal or no offsetting factors, and that will be used and useful for customer benefit in the rate year.[93] According to the Company, it excluded capital projects used to connect new customers and new revenue, and only included projects that do not produce new revenue.[94]

89 As an alternative to its preferred proposal, the Company offers another approach for calculating adjustments to include plant additions for 2008 and 2009, similar to the Staff approach and the Company's alternative approach for the electric rate base adjustment. In the Company's rebuttal case, Mr. Howell describes three natural gas distribution projects he says were completed and put in service between October 2008 and July 31, 2009: "Qualchan Reinforcement", "Nine Mile Gate Station", and "Gas Distribution Minor Blanket." He also provides estimates of offsetting factors for these projects. The net investment for these three projects is $4,373,358.[95]

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[90] DeFelice, Exh. DBD-1T at 2:7 – 3:7.

[91] Kermode, Exh. DPK-1T at 31:21 – 32:8.

[92] *Id.* at 32:12-18 and 35:12-23; *see also* Larkin, Exh. HL-1T at 14:19 – 15:13.

[93] DeFelice, Exh. DBD-4T at 5:5-19 and 11:1-13.

[94] Howell, Exh. DRH-1T at 3:14-19.

[95] *Id.* at 5:4 – 8:2.

90 Also in the Company's rebuttal case, Mr. DeFelice describes a fourth natural gas distribution project that was completed and put in service between October 2008 and July 31, 2009: "Replace Gas ERTs with Batteries Older than 10 Years". He provides an estimate of offsetting operation and maintenance costs and says that, net of estimated offsetting operation and maintenance cost savings, investment in this gas distribution project was $733,000.[96] Mr. DeFelice also describes three "general plant" projects he says were completed and in service by July 31, 2009, for a net investment of another $980,063.[97]

91 The Company proposes to pro form the above described four natural gas projects, and the portion of three additional general plant projects allocated to natural gas operations, that were completed and in service by July 31, 2009, totaling $5,516,000 in rate base, net of accumulated depreciation and deferred taxes through calendar year 2010. The effect of the Company's rebuttal case alternative is to reduce net operating income by $168,951 and increase revenue requirement by $894,000. The latter figure compares to the Company's original total request for $1,313,000 million of new revenue related to its 2008 and 2009 capital additions.[98]

92 *Commission Decision.* As post-test-year adjustments to rate base accounts, the Company's proposed natural gas capital additions adjustments must comport with all three of the principles guiding pro forma adjustment that we have previously discussed. We focus our analysis on the Company's alternative proposal. The adjustment the Company initially proposes involves a significant departure from measuring rate base as an average during the test-year. By proposing an end-of-period measurement (indeed, an end point three months *after* the end of the test-period) the Company eliminates the test year benefit of matching all cost of service elements. Moreover, the Company has taken no additional steps to cure the mismatch created by the end-of-period method by measuring historical revenues and other elements at the same point in time. As we noted in our discussion of the electric rate base adjustments, under exceptional circumstances we could accept a departure from

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[96] DeFelice, Exh. DBD-4T at 17:15-26.

[97] *Id.* at 18:1-36. Note that a portion of these general plant projects is also included in the Company's alternative electric capital addition adjustment.

[98] *Id.* at 16:1 – 17:2.

the convention of measuring rate base as a test year average, but the Company has not provided sufficient cause for us to do so here. Consequently, we reject the Company's initial proposed adjustment as flawed in method.

93 Turning to the rebuttal proposal, the Company provides evidence, in the form of a table (Exh. DBD-10), that purports to show the projects it seeks to add to rate base accounts were put in service by the middle of 2009. However, in contrast to the evidence of record on the electric plant additions, we have no Staff audit or testimony demonstrating the costs reported and the project completion dates. Lacking such demonstration, the post-test-year data contained in Exh. DBD-10 is not of the same quality as the audited data we rely upon in our analysis regarding the adjustments to electric rate base.[99]

94 With regard to the principle of matching, the Company asserts that the set of projects it seeks to include does not include projects undertaken to add new customers or to provide additional revenues. The Company provides estimates of the revenue or cost savings it believes could be attributable to each of the projects during the rate year. While these estimates may be accurate, this approach misconstrues the principle of matching. It implies that the necessary matching is limited solely to offsetting factors caused by the project in question. The principle of matching requires that <u>all</u> cost of service components – revenue, investment, expenses and cost of capital – be evaluated at a similar point in time. Staff is correct to point out that this requires consideration of all of the Company's costs and revenues.[100]

95 In ratemaking for the electric side of the Company's operations, the production property adjustment is a method applied broadly to rate year production plant, costs and revenues to scale them to test period loads. While this method does not provide a perfect replica of test year matching, it is superior to a project-by-project approach. There is no production property adjustment employed on the natural gas side, so the protections against injury to the matching principle afforded by that method are not present in the Company's case or generally in natural gas ratemaking.

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[99] We reiterate our previous cautions that data introduced late in a proceeding does not carry the benefit of full examination by our staff and the parties and therefore is accorded less reliability and weight.

[100] Staff Brief, ¶¶ 49-51.

96 Considering the lack of audited evidence regarding the actual amount of plant investment and the project completion dates, and the absence of a ratemaking mechanism to preserve against injury to the matching principle, we conclude that the Company's proposed pro forma adjustments to test period natural gas rate base are not appropriate and should be disallowed. Our decision again does not preclude recovery of the capital additions in a future proceeding where costs and offsetting benefits are reflected in test year data, or otherwise thoroughly documented consistent with the principles governing pro forma adjustments reiterated here.

d. Other Contested Pro Forma Adjustments

(1) Production Property Adjustment

97 *Positions of the Parties.* The Company makes a pro forma adjustment to both electric rate base and electric net operating income to reflect the ratios of test year retail load divided by the pro forma period and the projected rate period loads.[101] After reflecting the agreements in the Partial Settlement, the Company's adjustment reduces rate year adjusted net rate base by $5,926,000 and increases NOI by $2,014,000.[102]

98 The purpose of a production property adjustment is to adjust pro formed rate year production costs to comport with test year loads.[103] In this case, no party opposes the application of a production property adjustment; instead, the parties dispute the appropriate methodology. All parties also agree that, regardless of the methodology used, the final production property adjustment will depend on resolution of all production and transmission related adjustments. The adjustment, therefore, will require updating to reflect final decisions regarding these adjustments.[104]

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[101] Andrews, Exh. EMA-1T at 21:21 – 22:13.

[102] Andrews, Exh. EMA-6 at 9.

[103] *See* Kermode, Exh. DPK-1T at 24:14-20; *see also* Staff Brief, at 14-16.

[104] Knox, Exh. TLK-8T at 3:6-14.

99 The Company proposes a new method for calculating this adjustment that relies on separate production factors for 2009 and 2010, and application of these production factors only to pro formed costs, not to production costs already included in test year results. The Company asserts that only pro formed costs need be matched to test year loads and that unadjusted production costs do not require an adjustment to test year loads because they are already matched with test year billing determinants.[105] It claims that the method advocated by Staff, which applies the production factor to all rate year production plant and related costs, will cause the Company to under-recover its costs in the rate year.[106] Based on all of its proposed pro forma adjustments for capital additions, and after application of the revenue conversion factor, the Company's adjustment reduces the Company's revenue requirement by $4,024,000.

100 Staff argues for continued reliance on the established method for calculating the production property adjustment. According to Staff, the established method ensures proper matching of <u>all</u> production rate base, including pro forma plant additions, and production related expenses with the test year rate loads. Staff asserts that the purpose of the adjustment is to "bring the pro formed rate year costs, on a unit basis, back to the historical test year for proper matching and comparability of all costs used in the revenue requirement determination."[107] Staff says that its method allows the Company to recover its test year costs at rate year loads, which is the objective of this type of adjustment.[108] Based on its adjustments to capital additions, Staff's adjustment reduces rate year adjusted net rate base by $11,360,000 and increases NOI by $2,464,000.[109] After application of the revenue conversion factor, the net effect is to reduce the Company's revenue requirement by $5,469,000.

101 Public Counsel also proposes a production property adjustment. Public Counsel objects to the Company's adjustment because it includes the Company's projected capital additions for 2008 and 2009 as well as projected increases in property tax,

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[105] *Id.* at 2:17 – 3:3.

[106] *Id.* at 3:16 – 6:14.

[107] Kermode, Exh. DPK-1T at 25:4-7.

[108] Staff Brief, ¶ 39.

[109] Kermode, Exh. DPK-2, at 26:16-19.

operating and maintenance expense and other expenses with which it does not agree. In calculating its adjustment, Public Counsel uses two production factors. One is applied to test period production plant and the other is applied to Public Counsel's proposed pro forma adjustments to electric rate base and power costs for the rate year. Public Counsel's method differs from the Staff method and the Company method.[110]

102 The Company confirmed that Staff's method in this proceeding is the one used by the Company and approved by the Commission in Avista's last two general rate cases.[111] However, the Company points out a number of errors in the spreadsheet Staff used to implement the method and derive its adjustment.[112] Staff corrected these errors in a revised exhibit.[113]

103 *Commission Decision.* We noted earlier that the production property adjustment is an important mechanism for ensuring that pro forma adjustments to production plant and net power costs are properly matched to test period data. We are satisfied with Staff's representation that the method it advocates, and that the Company has used in the past, properly accomplishes the objective of the matching principle. Indeed, even Mr. Norwood, for the Company, describes application of the production property adjustment in a manner identical to the method used by Staff.[114] Staff's method recognizes that the whole of the pro formed production rate base will be used to accomplish service to customers in the rate year. Staff's method using a single, rather than multiple production factors, also recognizes that it is only the rate year costs that

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[110] Larkin, Exh. HL-1T at 10:12 – 11:12; Larkin, Exh. HL-3 at 10.

[111] Knox, TR. 692:23 – 693:1. *See UTC v. Avista Corporation*, Dockets UE-070804, UG-070805, and UE-070311 (*consolidated*), Order 05, Final Order Rejecting Tariff Sheets; Approving and Adopting Settlement Stipulation; Requiring Compliance Filing (Dec. 19, 2007) [hereinafter *2007 Avista Rate Case Order*]; *UTC v. Avista Corporation,* Dockets UE-080416 and UG-080417 (*consolidated*), Order 8, Final Order Approving and Adopting Multi-Party Settlement Stipulation and Requiring Compliance Filing (Dec. 29, 2008) [hereinafter *2008 Avista Rate Case Order*].

[112] Knox, Exh. TLK-8T at 8:5 – 11:5.

[113] Kermode, Exh. DPK-6 (revised October 5, 2009).

[114] Norwood, Exh. KON-1T at 20:26 – 22:4 ("Because retail rates are set using the lower number of customers and lower customer kWh sales for the 2008 test year, to preserve the matching principle, *the pro forma adjusted rate base* for the 2010 rate year is adjusted <u>back</u> to the 2008 test year through the production property adjustment." (underline in original, italics added)).

are in need of adjustment to accomplish matching to the test year. Consequently, we are not persuaded to adopt a different production property adjustment method than that used and approved in multiple recent rate cases. We approve the method Staff proposed.

104 As Staff and the Company agree, the exact magnitude of this adjustment will require revision to reflect the disposition of all related adjustments in this case. We therefore require the Company to recalculate the Production Property Adjustment using the method shown in Exhibit DPK-6 as part of its compliance filing.

(2) Labor – Executive and Non-Executive

105 *Positions of the Parties.* The Company proposed pro forma adjustments to electric and natural gas test year results to reflect labor expense increases for 2008, 2009, and 2010.[115] Staff and Public Counsel generally agree that known and measurable company obligations, such as union wage increases resulting from collective bargaining agreements or non-union wage increases approved by the board of directors, are proper adjustments.[116] Staff says that the Company's 2008 and 2009 labor adjustments, revised to reflect actual salaries, meet this standard.[117]

106 Public Counsel agrees that the actual salaries for 2008 and 2009 meet the standard of known and measurable. However, Public Counsel recommends adjusting the 2008 salaries paid to executives to the same annualized increase received by administrative employees.[118]

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[115] Andrews, Exh. EMA-4T-C at 6:14 – 8:11.

[116] LaRue, Exh. AMCL-1T at 5, Larkin, Exh. HL-1T at 11-13; *see also* LaRue, TR. 685:5-11. Public Counsel's approach differs slightly from Staff's due to the methodology utilized for annualizing 2008 wage increases.

[117] LaRue, Exh. AMCL-1T at 6:2-5.

[118] Larkin, Exh. HL-1T at 11:23 – 12:19.

107 The Company objects to Public Counsel's adjustment to 2008 executive salaries contending that its data represents actual salaries paid to officers in 2008, not an estimate.[119]

108 Both Staff and Public Counsel dispute any adjustment that includes future wage levels to which the Company has not obligated itself, such as the proposed adjustment for 2010 wage increases.[120]

109 Originally, the Company pro formed expected 2010 salary increases of 3.8 percent for administrative, union, and executive employees. On rebuttal, the Company re-aligned its predictions about 2010 salary increases to be consistent with industry projections as of September 2009. The Company argues that its projections based on industry studies and the likely outcome of union negotiations are a reliable forecast of labor cost increases in the rate year; further, the Company asserts that it has regularly granted wage increases in March.[121]

110 *Commission Decision.* Labor costs are undeniably an ongoing expense incurred by the Company. Where there is clear documentation that labor expenses will increase because of known and certain increases in salaries, it becomes easier for us to justify this sort of pro forma adjustment. However, the Company's argument that its proposed 2010 wage increases are known and measurable is not persuasive. As noted in our discussion of basic principles, budget projections and estimates do not meet this regulatory standard. The Company's updates to its wage figures during the pendency of this proceeding counter any argument that next year's salary increases, if any, are known and measurable.[122] Past practice may demonstrate that the Company traditionally grants salary increases every year in March, but in this record the amount

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[119] Andrews, Exh. EMA-4T-C at 11:5-8.

[120] Staff Brief, ¶¶ 14-16 and 18; Public Counsel Brief, ¶ 163.

[121] Andrews, Exh. EMA-4T-C at 9:20 – 12:14.

[122] We encourage the Company to refine its data when it can, but in recommending pro forma adjustments, we are limited to approving those where the effect is known and measurable. As an example of how updated data can convert projections into known and measurable changes, see our discussion of the property tax adjustment, below.

for 2010 is simply not known.[123] Forecasts and estimates are, by their nature, uncertain. Here, the evidence is clear that the Company is not yet obligated to pay any specific level of wage increase in 2010. The Company's witness, Ms. Andrews, confirmed that the Board has not yet approved any increases for 2010 and that the Company is not obligated by contract other than the collective bargaining agreement to pay any wage increase in March 2010.[124]

111 Turning to Public Counsel's recommendation to annualize the 2008 executive salaries based on the increase granted administrative employees, we find there is no justification to make this adjustment. The Company has revised its salary data to represent what was actually paid to officers. Public Counsel provides no compelling reason to depart from this actual data.

112 We find reasonable Staff's recommendation to include 2008 and 2009 wage levels that are approved and already in effect and adopt the pro forma adjustments to electric and natural gas shown in Table 4 and Table 5.

(3) Asset Management Program

113 *Positions of the Parties.* The Company's Asset Management Program (AMP) is a consolidated maintenance program for managing key components of Avista's transmission and distribution systems by modeling when to inspect and when to replace its wood poles, as well as evaluating downtown Spokane network and vegetation management programs.[125] Avista made pro forma adjustments to both its electric and natural gas results of operations to reflect its claim that AMP expenses have increased over 6 percent per year for labor, fuel and equipment costs. According

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[123] In these difficult economic times, it may be particularly hard to predict with any accuracy what an appropriate wage increase, if any, might be for Avista's employees and executive officers.

[124] Andrews, TR. 591:25 – 593:1.

[125] Kinney, Exh. SJK-1T at 17-28. Avista initiated the AMP in March 2004. Since at least early 2007, the AMP has included annual line patrols for all of the Company's 230 kV and some of the Company's 115 kV transmission corridors to ensure compliance with NERC Reliability Standard FAC-003-1. *Id.* at 15:37-38. The AMP also covers the Company's plans to perform vegetation management on a five year cycle for nearly 200 miles of its high pressure gas pipeline rights-of-way, in compliance with CFR 49 and WAC 480-93-188. *Id.* at 25:19 – 26:2.

to the Company, the three factors driving AMP costs higher than in the test period are the contract with Asplundh for vegetation management; special use permits and restrictions on road access by the U.S. Forest Service; and inflation of 6 percent based on the Asplundh contract.[126] The Company also asserts that our prior orders in Dockets UE-050482 and UE-070804 require it to increase its vegetation management and wood pole inspection programs, respectively.[127]

114 Commission Staff opposes this adjustment because it says the expenses proposed to be included are not known and measurable, but only management's estimates of future expenses. Further, there are no offsetting amounts for increased revenue or clear decreases in test year costs. Public Counsel also opposes these adjustments as not known and measurable and not offset with resultant cost savings or benefits, as was found to be the case in a recent proceeding in Idaho.[128]

115 On rebuttal, the Company asserted that its AMP expenses are not "merely budgeted costs" as Public Counsel contended, but based on "sound, historical experience" combined with a comprehensive asset management model that "maximizes the value of these capital assets" by "determining the future failure rates."[129] Even so, the Company conceded the absence of offsetting factors through 2010, but predicted there

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[126] Kinney, TR. 650:16 - 654:1.

[127] *UTC v. Avista Corporation,* Dockets UE-050482 & UG-050483 (*consolidated*), Order 5, Approving and Adopting Settlement Agreement with Conditions, ¶ 15 (Dec. 21, 2005) [hereinafter *2005 Avista Rate Case Order*] (Requiring the Company to spend approximately $2.8 million annually on electric and natural gas vegetation management programs); *2007 Avista Rate Case Order* (Line 9 of Appendix 1 to Appendix 8 of the Settlement Stipulation requires the Company to establish a one-way balancing account and report to the Commission on the level of wood pole capital and expenses).

[128] Larkin, Exh. HL-1T at 16-17.

[129] Andrews, Exh. EMA-4T-C at 19-23.

would be O&M savings in later years.[130] The Company included estimates of offsetting factors for some of the program components.[131]

116 *Commission Decision.* The Company's ongoing effort to implement a comprehensive and efficient program to manage maintenance, facility upgrades, and capital replacements in its transmission and distribution systems is commendable. This activity promises to maximize the value of Avista's facilities, minimize operations and maintenance costs, and demonstrates prudent management. However, this expectation alone is not sufficient to justify a pro forma adjustment. Here, the tests of whether a pro forma adjustment to expense for the AMP is appropriate are two-fold: (a) whether the Company has proven that expenses have increased by known and measurable amounts over test year levels, and (b) whether any increased known and measurable expenses are net of offsetting factors.

117 The Company's evidence for increased transmission level expenses driven in part by increased regulatory requirements is unavailing; the North American Electric Reliability Corporation (NERC) standards, which the Company claims are a key driver of increased costs, were actually in place prior to the test year.[132] Consequently, these requirements are not new and the test year values must reflect some level of compliance costs. Although the Company's historical experience with this ongoing program may demonstrate that costs are generally rising, our record contains no specific evidence of the costs (or increased costs) contained in the Asplundh contract, whether from a new requirement for U.S. Forest Service road access permits or from a contract escalator clause regarding inflation. Further, our orders in prior dockets do not require the Company to increase its expenditures for

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[130] *Id.* at 20:13-16.

[131] The Company's offsetting factors included benefits associated with components of the program for distribution, transmission, substation, and network expense. *See* Andrews, Exh. EMA-4T-C at 21:11 – 23:11.

[132] NERC adopted its NERC Reliability Standard FAC-003-1 on February 7, 2006, with an effective date of April 7, 2006. By its terms, companies are required to comply with this standard by February 7, 2007. Mr. Kinney testifies that all NERC reliability standards became mandatory in June 2007. SJK-1T at 15:37-38. Consequently, Avista's requirements under this standard were in effect during the test year.

either vegetation management[133] or wood pole inspections.[134] Even if we had mandated some escalation in Company expenditures in a previous order, the Company must carry the burden of proving those increases are known and measurable and that they are not offset by other factors; the Company fails to so in this docket.[135] While we appreciate that the Company has offered some estimates of offsetting factors, these amount to estimates of benefits which are used to offset estimates of costs. In short, we are left with budget estimates rather than known and measurable values. Therefore, we adopt Staff's and Public Counsel's recommendation to disallow the AMP adjustments to the electric and natural gas test years.

(4) Information Systems

118 *Positions of the Parties.* The Company makes pro forma adjustments to both electric and natural gas test year results for labor and non-labor informational services costs planned for 2010 that exceed test year costs.[136] Its proposed adjustments would increase revenue requirement by $1,114,000 on the electric side and increase revenue requirement by $287,000 on the natural gas side.[137] The Company says these increased expenses are for additional labor costs to support software, mobile dispatch and outage management systems, non-labor costs for various software license and maintenance fees, and non-labor costs associated with replacing certain hardware and software.[138]

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[133] *See infra*, n.127, *2005 Avista Rate Case Order*, ¶ 15. Our order did not compel that more than $2.8 million be spent on vegetation management, nor did we address how an increase in cost for this purpose should be treated in future cases.

[134] *Id.*, *2007 Avista Rate Case Order*. Our order did not compel any increase in expenditures nor did we address how any increase in costs should be treated in future proceedings.

[135] According to Company witness Scott Kinney, the net overall effect of the Company's increased electric AMP spending on O&M costs is an approximately $100,000 increase over the test period for 2010. *See* Kinney, Exh. SJK-4T at 14:13 – 15:11.

[136] Andrews, Exh. EMA-1T at 26:12-15.

[137] Andrews, Exh. EMA-4T-C at 25:3-5.

[138] Kopczynski, Exh. DFK-1T at 7:22 – 8:7.

119 Staff again asserts that these expenses are "planned," not known and measurable, and that the Company's adjustment does not adequately quantify any offsetting benefits of the pro formed costs.[139] Public Counsel raises similar concerns.[140] Staff cites the paucity of information in the Company work papers, noting that the Company appears to "shift to Staff the responsibility to build detailed support for the proposed Company adjustments, through audits or data requests."[141]

120 The Company responds that the costs proposed to be pro formed are known and measurable because they are associated with existing technology and labor that are already employed. It argues that many of the increased expenses do not provide offsetting benefits because they are associated with "compliance purposes" such as disaster recovery, business continuity, and maintaining a secure cyber and data environment.[142] The Company's witness, Mr. Kensock, provides a list of 16 projects for which he identifies cost and offset estimates and an explanation of each project. He explains that the offsets he calculates represent savings in the information services department, rather than savings in the "operating areas in which these services are being utilized." He asserts that savings offsets in other operating areas are already represented in the test year for applications initiated prior to, or during the test year. For three of the projects – Mobile Dispatch, Outage Management, and Web Applications – Mr. Kensock explains that new full-time employees are being hired and the labor expensed rather than capitalized in project development. For another project (Technology and Electronic Payment Service Providers) the Company estimates a 100 percent offset in costs and for one project the Company has delayed implementation until 2010. Mr. Kensock removes the cost for these two projects in revising the Company's adjustment on rebuttal. For the remainder of the projects, he asserts that the costs have already been incurred since the close of the test year or are predictable based on license fees for new employees.[143] He concedes that the cost and

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[139] Kermode, Exh. DPK-1T at 43-44.

[140] Larkin, Exh. HL-1T at 17.

[141] Kermode, Exh. DPK-1T at 43:18 – 44:4.

[142] Kensock, Exh. JMK-1T at 3:9-13.

[143] *Id.* at 4:1 – 10:7.

offset figures he provides are estimates and that the two projects for which he removed the costs in revising for rebuttal the Company's originally filed adjustment were characterized as known and measurable in the original filing.[144]

121 *Commission Decision.* We encourage and support utility efforts to apply new technologies, including information processing systems, which may have the end result of benefiting customers. The Company's efforts in this regard are not questioned by Staff or Public Counsel, nor do we question them here. The Company claims that a majority of the costs it says have increased have been, or are being, incurred and that it has attempted to quantify offsetting benefits – at least within the information services department.

122 While our record contains summary tables of expenses, it does not contain invoices or other detailed evidence documenting actual expenditures, invoices, contracts, or other specific obligations to demonstrate that costs have increased beyond what is included in test year data. Nor does our record include details of the Company's calculation of estimates of offsetting savings. On the other hand, our record does show changes in what the Company initially characterized as known and measurable as the Company's plans have changed during the pendency of our review. This alone casts suspicion on the validity of the Company's proposed pro forma adjustment. Finally, the Company's estimates of offsetting benefits measure only the effect on costs incurred within the information services department, and not more broadly across Company operations. We understand that the Company claims that savings for existing applications are already represented in the test year, but given that three of the projects involve shifting labor from a capital to an operating expense, it is not reasonable to conclude that there are no effects at all realized in the rest of the Company's operations.

123 We conclude that the Company's pro forma adjustments for information services are not sufficiently supported because they lack specific cost documentation and lack a complete analysis of offsetting factors. Our rules require comprehensive and detailed work papers to support proposed pro forma adjustments. The Company's electric and natural gas pro forma adjustments are not supported as required and are not accepted.

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[144] Kensock, TR. 688:11 – 690:15.

(5) Incentive Program

124 *Positions of the Parties.* Avista makes incentive payments to officers and employees based on the Company achieving customer satisfaction and reliability targets. The actual incentive amounts paid are based on savings in utility operation and maintenance costs. In this case, the Company makes pro forma adjustments to both electric and natural gas test year results for its incentive program expenses to the level it expects to pay in 2009. In addition, the Company proposes to "normalize" recovery of incentive payment amounts in rates to a six year average based on payouts made from 2003 through 2009.[145] The Company's proposed adjustments would increase electric revenue requirement by $574,000 and natural gas revenue requirement by $159,000.

125 Staff argues that the Company has not demonstrated any rationale explaining why the 2009 incentive payments are not normal and thus fails to provide any justification for using a normalizing average rather than actual test year costs.[146] Staff recommends eliminating the six year averaging and the use of the Consumer Price Index to convert all dollars to 2008. It proposes an adjustment to reduce test year expense producing a reduction in electric revenue requirement of $18,202 and a reduction in gas revenue requirement of $5,029.[147]

126 Public Counsel also opposes the Company's use of the six-year average, arguing that incentive payout levels have been declining and that no increase is likely during 2009 due to the current economic conditions, making the known 2008 level an adequate representation.[148] Public Counsel argues that no pro forma adjustment is appropriate for either electric or natural gas operations.

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[145] Andrews, Exh. EMA-1T at 29:14 – 30:18.

[146] LaRue, Exh. AMCL-1T at 10-12.

[147] *Id.* at 11:13 – 12:2.

[148] Larkin, Exh. HL-1T at 19-20.

127 On rebuttal, the Company notes that Staff relied on an average for incentive pay in the Company's 2007 rate case when it served to reduce revenue requirements.[149] Further, the Company disagrees with Public Counsel's argument regarding economic conditions stating that its incentive program triggers are independent of the health of the economy. At hearing, Company witness Ms. Andrews testified that incentives are paid only if a target based on operation and maintenance cost per customer is achieved.[150]

128 *Commission Decision.* We last thoroughly analyzed Avista's incentive program in its 1999 general rate case. In that proceeding we disallowed certain costs tied to financial performance and found that the program was not tied to ratepayer benefit. The Commission nevertheless approved the program subject to correction of those problems.[151] The four Avista general rate cases since 1999 were resolved, at least in part, by settlement, and none specifically raised the treatment of an incentive program as a topic of interest.[152] In this proceeding, the issue of the incentive program is, for the first time in nine years, presented as a litigated matter for Commission review and decision. However, the record in this proceeding is insufficient to allow a comprehensive review or justify deviation from test year results.

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[149] Andrews, Exh. EMA-4T-C at 29-31.

[150] Andrews, TR. 607:12 – 610:24. Ms. Andrews also confirmed that ratepayers, not shareholders, pay both the incentive payments and the operation and maintenance costs upon which the incentive program is based. *See* Andrews, TR. 617:1-18.

[151] *See UTC. v. Avista Corporation*, Dockets UE-991606 & UG-991607 Third Supplemental Order, at ¶¶ 271-273 (Sept. 29, 2000) [hereinafter *1999 Avista Rate Case Order*]. Since the 1999 rate case, Avista's incentive program has been tied to reduction in O&M costs. *See* Andrews, Exh. EMA-4T-C at 17:3-6.

[152] *See UTC v. Avista Corporation*, Docket UE-011595, Fifth Supplemental Order (June 18, 2002) [hereinafter *2001 Avista Rate Case Order*] (adopting a settlement stipulation which did not specifically address the incentive program); *2005 Avista Rate Case Order* (approving and adopting a settlement stipulation which did not specifically address the incentive program); *2007 Avista Rate Case Order* (approving and adopting a settlement stipulation that did not specifically address the matter of incentive programs, although the stipulated results of gas and electric adjusted results of operations did include restated incentive amounts); *2008 Avista Rate Case Order* (approving and adopting a multi-party settlement that includes the provision "adjust incentives to actual" in the appended summary table of agreed adjustments).

129 Thus, we reject both the Staff and Company adjustments and leave the Company's incentive program costs for electric and natural gas operations at the test year level. We direct the Company and all interested parties to review the program for a more thorough evaluation of how the incremental cost of employee incentives should be treated in rates. Based on such discussions and review, we direct that the Company address in its next rate case whether ratepayers should pay the incremental cost of incentives to achieve O&M savings when ratepayers are already paying the full costs of O&M. Further, if the cost of incentives is appropriate to include in rates, parties should also explain whether these costs should be normalized.

(6) Insurance

130 *Positions of the Parties.* The Company adjusts insurance expense for general liability, directors and officers (D&O) liability, and property to the actual cost of insurance policies in effect in 2009.[153] Its adjustments increase electricity and natural gas revenue requirement by approximately $228,000 and $63,000, respectively.[154]

131 Staff and Public Counsel agree with the Company that insurance costs should be updated to reflect actual premiums paid for 2009. Staff agrees with the Company's proposed allocation of some of the cost to subsidiaries, and with the allocation of costs between electric and gas operations. Public Counsel argues Avista is allocating all of the D&O insurance premium to the utility and advocates that a portion be allocated to subsidiaries.

132 Staff and Public Counsel also argue that D&O insurance should be allocated 50/50 between ratepayers and shareholders because it provides benefits to both shareholders and ratepayers.[155] Staff proposes adjustments that *reduce* electricity and natural gas

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[153] Andrews, Exh. EMA-1T at 34.

[154] Andrews, Exh. EMA-6 at 12 and Exh. EMA-7 at 9.

[155] LaRue, Exh. AMCL-1T at 16-18. Staff also notes that California, Arkansas, and Connecticut share the D&O insurance cost 50/50, with Connecticut recently increasing shareholder responsibilities to 75 percent. *Id.* at 17:10 – 18:6. At hearing, Staff witness Ann Larue testified that her research showed that shareholders file the bulk of lawsuits against directors. *See* LaRue, TR. 682:18 – 683:5.

revenue requirement by approximately $148,000 and $19,000, respectively. Public Counsel's proposed adjustments to insurance and its separate adjustment to D&O insurance *reduce* electric and natural gas revenue requirements by approximately $198,000 and $51,000.[156]

133 The Company disagrees with the recommendation for a 50/50 sharing of the cost of D&O insurance between ratepayers and shareholders. The Company argues that without D&O insurance it would be unable to retain qualified directors who are vital to the fundamental governance of the Company. According to Company, the purpose of D&O insurance, like other insurance the Company secures, is to transfer risk to third-parties and reduce volatility in utility expenses and exposure to catastrophic financial losses.[157]

134 As an alternative position, if the Commission chooses to require that shareholders bear some part of the D&O insurance premium, the Company recommends a 90/10 split between ratepayers and shareholders. This is based on the formula currently used to allocate officer compensation between ratepayers and shareholders. The Company says this split would "equate to a revenue requirement reduction of $72,000 electric and $20,000 gas" from its adjustment.[158] Subtracting these figures from the Company's adjustment yields an overall insurance adjustment that increases electric and natural gas revenue requirements by $156,000 and $43,000, respectively.

135 *Commission Decision.* Aside from an error the Company points out in Public Counsel's adjustment,[159] the dispute about this adjustment centers on whether the cost

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[156] Larkin, Exh. HL-1T at 21-23. *See also* Exh. HL-5 at 4, column C-10, and Exh. HL-6 at 3, column C-5.

[157] *See* Andrews, TR. 525:25-526:21. Ms. Andrews also testified that risk is a factor in determining insurance coverage and that Avista has few subsidiaries that impose risks for which insurance coverage is secured. *Id.* at 581:1 – 584:2. According to Ms. Andrews, the cost of D&O insurance has declined since Avista sold Avista Energy. In 2007, prior to this sale, the 66 percent allocation to utility operations amounted to $787,000; in comparison, in 2009, the 98 percent allocated to utility operations totaled $721,000. Andrews, Exh. EMA-4T-C at 28:1-10.

[158] Andrews, Exh. EMA-4T-C at 31:2-4.

[159] In addition to opposing the 50/50 split, the Company objected to the level of Public Counsel's proposed D&O adjustment because it does not reflect the updated insurance premium information

of D&O insurance premiums should be split between customers and shareholders and, if so, by what percentages. There is no dispute about whether D&O insurance is a necessary expense for a publicly owned company, or whether the level of insurance coverage and premium amount paid by Avista is appropriate. The Company's argument that without insurance protection it would be unable to attract and retain qualified directors is persuasive. The Company's suggestion, however, that the shareholders do not benefit from the protection insurance provides the directors does not persuade us.[160] Clearly the shareholders have an interest in a well-managed company and attracting good directors promotes good management and benefits all involved, as they ultimately bear the responsibility of ensuring the Company is properly managed.[161]

136 We find that a company's directors benefit both shareholders and ratepayers. Shared benefit justifies some level of shared responsibility to pay the cost of D&O insurance. Staff and Public Counsel point us to decisions in other jurisdictions that require the cost of D&O insurance to be shared 50/50 between shareholders and ratepayers, but fail to establish how those decisions are relevant here and not simply illustrative of what has been done elsewhere.

137 We find on the basis of our limited record here that D&O insurance is a benefit that is part of the compensation package offered to attract and retain qualified officers and directors. Accordingly, it makes sense to split the costs in the same manner we require other elements of their compensation to be shared. Based on the formula currently used to allocate officer compensation between ratepayers and shareholders, this results in 90 percent of the costs being included for recovery in rates. After accepting the Company's revised overall insurance adjustment filed on rebuttal, our

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that has otherwise been agreed to among the Company, Staff, and Public Counsel. Andrews, Exh. EMA-4T-C at 27:6-14.

[160] Andrews, TR. 525:5-7.

[161] We note that Avista's directors owe a fiduciary duty to the corporation's shareholders to oversee with diligence and reasonable care the actions of the corporation. Simply stated, the directors must act *affirmatively and in good faith*, to protect the interests of the Company and its stockholders, and to refrain from doing anything that would injure the Company or deprive the Company of profit or an advantage that might properly be brought to the Company for it to pursue. The directors owe no fiduciary duty to protect the interests of the ratepayers.

approved 90/10 split results in an additional revenue requirement of $156,000 for electric and $43,000 for natural gas.[162]

(7) Director Fees & Board Meetings

138 *Positions of the Parties.* Avista included $45,229 and $12,501 (electric and gas) in test year cost from Board of Director meetings,[163] and $544,333 and $150,542 (electric and gas) in test year costs for Board of Directors fees.[164] Staff agrees that Board of Director meetings are a necessary cost of doing business and contends that the meetings benefit both ratepayers and shareholders. Therefore, Staff recommends adjusting the Company's expenses to reflect a 50/50 sharing of the meeting costs.[165] Staff does not address or propose an adjustment to Directors' fees.

139 Public Counsel recommends a 50/50 split between ratepayers and shareholders for all expenses incurred for Directors' meetings and Directors' fees. According to Public Counsel, the Board is the Company's ultimate governing authority, overseeing all company activities, and its primary responsibility is to protect shareholders' assets. Therefore, Public Counsel contends that it is not unreasonable to ask shareholders to bear half of the cost of the Board's meetings as well as half the cost of paying an attendance stipend to directors who are working part-time on behalf of the Company's shareholders.[166]

140 The Company disagrees with the arguments made by both Staff and Public Counsel, noting that Board of Directors expenses are a necessary expense of doing business to support financing the company and maintain access to capital markets.[167] According

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[162] We recognize that these figures may appear to be of modest consequence in this proceeding, but the question of shareholders and ratepayers equitably sharing the costs of mutually beneficial Company obligations is an important principle.

[163] Larkin, Exh. HL-1T at 23:20-24:2.

[164] *Id.* at 25:5-9.

[165] Kermode, Exh. DPK-1T at 20:5-21.

[166] Larkin, Exh. HL-1T at 23-25; Kermode, Exh. DPK-1T at 20.

[167] Andrews, Exh. EMA-4T-C at 31-33.

to Company witness Ms. Andrews, recruitment and retention of qualified directors who provide overall guidance for the utility "inures to the benefit of ratepayers."[168] However, Ms. Andrews acknowledged that shareholders nominate and elect the Directors, not ratepayers. Ms. Andrews also confirmed that the Directors act on shareholder proposals, oversee both utility and non-utility activities of the corporation, and receive part of their compensation in the form of common stock.[169] As with the D&O insurance expense, the Company proposes a compromise of 90/10 sharing between ratepayers and shareholders if the Commission determines any sharing is necessary.[170]

141 *Commission Decision.* This disputed issue is similar in some respects to the disagreement over D&O insurance adjustments. The evidence of record regarding Directors' fees and Directors' meetings also supports the conclusion that the activities of the Board are essential to the function of the utility and its access to capital markets and therefore serve to benefit both shareholders and ratepayers. Both Staff and Public Counsel agree with the Company that the Board is necessary and that its expenses are a necessary cost of doing business.

142 The Company asserts that all of these costs should be borne by ratepayers or that, at most, there should be a 90/10 sharing. In our analysis of D&O insurance costs, we focused on the point that it is part of the officers' and directors' compensation package, necessary to attract and retain qualified management. In contrast, our focus here is on Board activities and expenses incurred during the year, many of which are shown by the record to not provide ratepayer benefit.[171] The record supports a finding

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[168] *Id.* at 32:5 – 33:2. At hearing, Ms. Andrews testified that shareholders benefit from a well-run company, but that "customers are the major benefit of the activities that are done by the board." *See* Andrews, TR. 526:9-21.

[169] *Id.* at 561:18 – 569:8.

[170] *Id.* at 32:5-11. According to Ms. Andrews' calculations, a 90/10 split would reduce revenue requirement for meetings by $5,000 and $1,000 (electric and natural gas), respectively.

[171] At hearing, Company witness Ms. Andrews confirmed a number of extravagances associated with Board of Director meetings, to include expensive hotels, meals, cruises, museum visits, Directors' gifts, first class air fare, and entertainment. Ms. Andrews made some corrections to several thousand dollars in meeting cost items that should have been charged to non-utility

that the Board of Directors provides services that benefit shareholders to the same extent those activities benefit ratepayers. Therefore, we determine Directors' Fees and Meetings costs should be shared equally between shareholders and ratepayers. The effect of adopting this adjustment is to increase electric and natural gas net operating income by $192,000 and $53,000, and reduce revenue requirement by $309,000 and $85,000, respectively.[172]

(8) Injuries & Damages

143 *Positions of the Parties.* The Company included a restating adjustment to replace the "accrual with actuals to obtain the six-year rolling average to injuries and damages not covered by insurance." The effect of the proposed adjustment is to decrease net operating income by $56,000 and $42,000 for electric and natural gas, respectively.[173] The revenue requirement impacts are an increase of $90,000 for electricity and a decrease of $68,000 for natural gas.

144 Staff does not oppose the Company's adjustment. Public Counsel does not object to the proposed adjustment, but argues that the Injuries and Damages reserve balance should be deducted from rate base. Public Counsel argues that to properly match the rate base with the expenses charged to ratepayers for injuries, the injuries and damages reserve liability must be deducted from rate base. Public Counsel's recommended adjustment to rate base removes the reserve balances and reflects the

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accounts and confirmed that first class air fare would no longer be booked to utility cost. *See* Andrews, TR. 570:5–575:17. These sorts of expenses, particularly in an era of belt tightening and cutbacks, do not cast the Company in the best light, particularly when seeking ratepayer dollars for such expenses. In any future rate proceedings, we expect that the Company will sort out those expenses related to Board of Directors' meetings that do not have any benefit to ratepayers and make the appropriate restating adjustment at the outset. The Company should not expect Public Counsel or Commission Staff to perform that review function.

[172] In essence, we adopt the end result of Public Counsel's proposed adjustment, though we reach that conclusion by a different analysis.

[173] Andrews, EMA-1T at 17:14-19 and 42:3-8.

effects on deferred taxes; as corrected at hearing, it would reduce electric rate base by $107,000 and natural gas rate base by $57,000.[174]

145 The Company opposed Public Counsel's methodology, even with corrections to calculations, because "only actual claims that have been paid are included in the utility's costs of service" and "the Company has not otherwise collected from ratepayers the reserve that has been recorded for financial purposes only."[175]

146 *Commission Decision.* We conclude that Public Counsel's proposed modification to the Company's adjustment is flawed. Such an adjustment is not consistent with the standard accounting practice that we have previously approved for the Company's injuries and damages reserve. The Company adequately explained its rationale and methodology for this adjustment as originally proposed. Therefore, we approve the Company's proposal.

(9) Customer Deposits

147 *Positions of the Parties.* Staff recommends adjustments to deduct from electric and natural gas rate base the average of monthly averages of customer deposits held by the Company. Staff argues that these deposits are a source of capital to the Company supplied by ratepayers, not by investors, and therefore should not be included in the Company's rate base. According to Staff, this capital is less expensive than the Company's cost of capital since the customer deposits earn interest at 0.42 percent.[176] The effect of Staff's proposed adjustment on the electric side is to reduce rate base by $2,473,256 and reduce net operating income by $6,752, for a revenue requirement

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[174] *See* Larkin, Exh. HL-1T at 29:9 – 30:24 for original calculations proposing a $7.7 million reduction in electric rate base and a $1.2 million reduction in natural gas rate base. *See* Larkin, TR. 694:15 – 695:8 and Exh. B-5 for corrected calculations.

[175] Andrews, Exh. EMA-4T-C at 38:5 – 39:16. *See also* Avista's Post-Hearing Brief, ¶ 121, nn.48 and 49.

[176] Staff also adjusts the Company's net operating income to reflect payment of interest on the deposits.

decrease of $334,000. On the gas side, this will reduce rate base by $1,353,000 and net operating income by $3,861 for a revenue requirement decrease of $173,000.[177]

148 The Company opposes the concept of treating customer deposits as a form of financing. The Company asserts that it uses customer deposits to manage costs associated with its uncollectable accounts receivable, a short-term function. Thus, according to the Company, Staff's method effectively deprives the Company of its full return on the deducted rate base in exchange for compensation at the short-term interest rate the deposits actually receive. The Commission's rules and Company's implementing tariff make clear that the deposits must be returned, with interest, to customers after 12 months of solid payment history. Therefore, the Company interprets the rule and tariff language to mean that "customer deposits are simply a tool for the management of accounts receivable write-offs."[178]

149 *Commission Decision.* We have established the exclusion of customer deposits from rate base as our standard practice.[179] The Company does not deny that it holds a balance of customer deposits and does not argue that these deposits are somehow separated from its other working capital. The Company merely points to the rule and tariff language governing the charging and interest on deposits, but fails to explain how this language limits its use of the deposit money to "managing uncollectables." Requiring a utility to hold and then return a customer's deposit at a future time certain does not limit the Company's use of those funds to a single use during the interim holding period. We find the Company's assertions unpersuasive and adopt Staff's adjustments to electric and natural gas rate base.

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[177] Kermode, Exh. DPK-1T at 17:18 – 19:19 and Exh. DPK-2 at 4 (both exhibits revised November 6, 2009). We note that Public Counsel proposed a similar adjustment, but originally recommended a different calculation for the interest expense. At hearing, Public Counsel adopted Staff's calculation and now proposes an adjustment identical to Staff's. *See* Exh. B-5.

[178] Andrews, Exh. EMA-4T-C at 34:18 – 37:29.

[179] In regulating Puget Sound Energy, this has been the norm for approximately 25 years. Kermode, Exh. DPK-1T at 19:2-10. We recently approved this same treatment for PacifiCorp in an uncontested adjustment in that utility's 2006 general rate case. *UTC v. PacifiCorp,* Dockets UE-061546 & UE-060817 (*consolidated*), Order 8, Final Order Rejecting Tariff Sheets; Authorizing and Requiring Compliance Filing, ¶ 59 (June 21, 2007).

(10). Property Taxes

150 *Positions of the Parties.* The Company included a restating adjustment in its original filing to update property taxes to what was then (in January 2009) the most current information and to eliminate adjustments made "in the prior year." This adjustment included property taxes now imposed by Oregon authorities on the Coyote Springs generating plant.[180] The Company's initial restating adjustment <u>decreased</u> electric net operating income by $939,000 and <u>increased</u> natural gas net operating income by $193,000.

151 Public Counsel opposed the adjustment for electric operations because the Company's adjustment based its calculations on projected taxes, which were therefore not known and measurable and not matched to test-year rate base at September 30, 2008. Public Counsel agreed with the natural gas adjustment to decrease property taxes.[181]

152 Staff recommended a property tax adjustment, but relied on actual tax assessments for 2009, rather than the projections used by the Company. Staff's adjustment decreases net operating income for the electric side by $127,000 and increases net operating income for the natural gas side by $486,000. The related changes to revenue requirement are an increase of $205,000 for electricity and a decrease of $781,000 for natural gas.[182]

153 *Commission Decision.* The Company agrees with Staff's electric and natural gas adjustments reflecting actual 2009 property tax rates and assessments.[183] Public Counsel's selective handling of the proposed electric and natural gas property tax adjustments seems arbitrary and we reject it.

154 This pro forma adjustment illustrates the basic principles we discussed earlier in this order. Property taxes are an annual expense that is consistently known and must be

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[180] Andrews, Exh. EMA-1T at 16:21 – 17:5.

[181] Larkin, Exh. HL-1T at 8:16 – 9:24.

[182] Kermode, Exh. DPK-1T at 16:11 – 17:12.

[183] Andrews, Exh. EMA-4T-C at 33:17 – 34:11.

planned for every year. However, the exact amount of these taxes remains unmeasurable until the taxing authorities announce rates and property valuations for any given tax year. It is wholly appropriate to pro form new tax rates and assessments once they become measurable. Therefore, we approve the adjustments agreed to by Staff and the Company and reject Public Counsel's proposed adjustments. The effect is to decrease net operating income for the electric side by $127,000 and increases net operating income for the natural gas side by $486,000. The related changes to revenue requirement are an increase of $205,000 for electricity and a decrease of $781,000 for natural gas.

(11) Coeur d'Alene Settlement

155 *Positions of the Parties.* In its 2008 electric general rate case in Docket UE-080416, Avista sought recovery of costs associated with the settlement of the Coeur d'Alene Tribe's (Tribe) claim for damages related to the operation of Avista's Spokane River Hydroelectric Project (Project), including its Post Falls hydroelectric facility located on the Spokane River downstream of Lake Coeur d'Alene.[184] Avista began operating the Project under Idaho state authority in 1907 and in 1972 requested a FERC license for its continued operation, but the Coeur d'Alene Tribe objected and intervened, claiming title to the lake.[185]

156 In 2001, after years of litigation in a number of forums, the United States Supreme Court ultimately determined that the United States holds, in trust for the Tribe, those portions of the lake within the boundaries of the Coeur d'Alene Reservation.[186] The Court's ruling did not settle the Tribe's dispute with Avista related to the historic and future use of the lake to benefit Project operations, including compensatory claims founded in Section 10(e) of the Federal Power Act for inundating reservation lands.[187] However, in 2008, Avista and the Tribe reached a comprehensive settlement whereby

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[184] *2008 Avista Rate Case Order*, ¶ 67.

[185] *Id.*, ¶ 68.

[186] *Id.*

[187] *Id.*

Avista agreed to compensate the Tribe for past damages and future use of the lake to serve the Project.[188]

157 In approving the Settlement proposed in Docket UE-080416, the Commission allowed Avista to defer its Washington share of the 2008 and 2009 payments to the Tribe, totaling $35.4 million, as a regulatory asset (CDA Asset), deferring recovery in rates spread over the remaining life of the project.[189] The Commission's approval of the Settlement in that docket resolved the accounting for the regulatory asset, but did not actually include recovery of the asset amortization in rates.

158 Public Counsel and other joint parties opposed the Settlement terms arguing that Avista's payments to the Tribe should be disallowed as imprudent because Avista "admitted to past trespass."[190] They also asserted that the settlement with the Tribe would require current customers to pay for past misconduct and usage charges resulting in retroactive ratemaking in violation of RCW 80.28.020, which requires the Commission to set rates prospectively.[191] The joint parties argued that the past Section 10(e) usage costs and past trespass damages are costs that should have been included in ratemaking for previous periods.[192]

159 The Commission rejected the joint parties' argument that Avista's operation of the Project or its actions in response to the Tribe's claim were imprudent, finding instead that "Avista operated the Project with authority from the entity it reasonably believed was the lawful owner, the State of Idaho, and, when challenged, it defended its right to operate it pursuant to the authority granted." The Commission also found that "without further legal recourse, Avista acted prudently to settle its dispute with the

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[188] *Id.*, ¶ 69. As compensation for past trespass and Section 10(e) water storage claims, Avista agreed to pay the Tribe $25 million in 2008, $10 million in 2009, and $4 million in 2010. Future Section 10(e) compensation consists of flat annual payments of $400,000 for the first 20 years of the license and $700,000 flat annual payments for the remaining 30 years of the license.

[189] *Id.*, ¶ 70. For details on the resulting *pro forma* adjustments, *see* ¶ 71.

[190] *Id.*, ¶ 72.

[191] *Id.*

[192] *Id.*

Tribe and wrap the Project's relicensing issues into a comprehensive agreement ensuring long-term availability of valuable hydroelectric resources for the benefit of Avista's current and future ratepayers."[193]

160 The Commission also disagreed with the joint parties' assertion that the settlement constituted retroactive ratemaking, determining instead that "retroactive ratemaking involves the *current* collection, through rates, of *past* obligations," and noting that "until Avista reached a settlement earlier this year, it had no obligation to the Tribe."[194]

161 Public Counsel appealed the Commission's decision in Dockets UE-080416 and UG-080417 to the Thurston County Superior Court.

162 Avista now proposes to give effect to the cost-recovery terms approved in Docket UE-080416 through a pro forma adjustment adding $16.8 million to electric rate base, decreasing NOI by $539,000 and increasing revenue requirement by $3.1 million at the Partial Settlement rate of return.[195] The adjustment includes one year of amortization based on an asset life of 45 years as well as the annual payment for 2009 agreed under the Tribal Settlement for use of the Tribe's property.

163 In this proceeding, Public Counsel points to its pending appeal and opposes the Company's adjustment. Public Counsel apparently accepts a pro forma adjustment to include the annual payment made under the agreement for use of Tribal property, but proposes to exclude amortization of the deferred asset and principal balance of $16.8 million.[196] Public Counsel's proposed adjustment decreases NOI by $168,000, increases revenue requirement by $270,000 and allows no adjustment to rate base.

164 The Company acknowledges that the matter is under appeal, but argues that the Commission's Order in Docket UE-080416 is still in effect. The Company contends

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[193] *Id.*, ¶ 77.

[194] *Id.*, ¶ 78.

[195] Andrews, Exh. EMA-1T at 28:3-19.

[196] Larkin, Exh. HL-1T at 17:23 – 18:12.

that its adjustment is consistent with that order and that Public Counsel's adjustment should be rejected.[197]

165 *Commission Decision.* Public Counsel's appeal of our order in Dockets UE-080416 & UG-080417 (*consolidated*) is still pending before the court.[198] The Company is correct that unless and until the court orders otherwise, the provisions of our order are still in effect. The Company's pro forma adjustments in this proceeding are consistent with our prior order and are approved.

(12) ERM Surcharge

166 *Positions of the Parties.* Schedule 93 is the Power Cost Surcharge added to base electricity rates to recover deferral balances generated by the Energy Recovery Mechanism (ERM) approved by the Commission in Docket UE-011595.[199] According to the Company, the deferral balance was $15.7 million as of September 2009 and projected to decline to $4.3 million by the end of December 2009.[200]

167 The Company proposes to eliminate the current Schedule 93 surcharge at the time the general rate increase is implemented, and to carry any remaining deferral balance forward for recovery in a future period.[201]

168 The Company says that the current ERM surcharge is 7.4 percent, based on currently charged base rates.[202] It projects that the balance will reach zero in February 2010,

[197] Andrews, Exh. EMA-4T-C at 43:5-15.

[198] We understand that on Friday, December 18, 2009, the Thurston County Superior Court issued an oral decision that would uphold the Commission's Order in this matter.

[199] *2001 Avista Rate Case Order*; Settlement at 7.

[200] Docket UE-011595, Monthly Power Cost Deferral Report, September 2009 (filed October 14, 2009).

[201] Morris, SLM-1T at 3:3-5 and Norwood, KON-1T at 30:18-20. The Company did not file a proposed change to Schedule 93 with the tariffs in this case. Schedule 93 is not under suspension. Mr. Hirschkorn testifies that it "would file Schedule 93 with its tariff compliance filing in this case to reduce the present surcharge rate(s) to zero." Hirschkorn, BJH-1T at 6:1-3.

[202] Hirschkorn, BJH-1T at 2:27-29.

and contends that eliminating the surcharge would "partially offset the rate impact on customers and eliminate the number of rate of rate impacts experienced by customers in a short period of time, especially during the winter months."[203]

169 Staff opposes eliminating the surcharge before the ERM deferral balance goes to zero. Staff argues that it is appropriate for customers to see the surcharge reduced to zero "on its own merits." Staff contends that if the deferral balance reaches zero in January or February 2010, customers will see a surcharge go away that had been in place on their bills since October 2001.[204]

170 Responding to Staff, the Company modified its proposal. Instead of eliminating the surcharge, it proposes to reduce the surcharge to a level adequate to eliminate the deferral balance over 12 months. This change would be implemented at the conclusion of this case. The Company estimates that the surcharge would be reduced to approximately one percent.[205]

171 Public Counsel, does not oppose the Company's proposal, but says that elimination of the surcharge should not be considered "as a component of the overall revenue request."[206]

172 ICNU favors the Company's modified proposal and says that the ERM surcharge should be reduced on the effective date of the new rates approved in this proceeding "in the interests of rate stability."[207]

173 *Commission Decision.* The Company has not filed a change to the Schedule 93 tariff as a part of this rate proceeding. Consequently, the tariff is not suspended and is not at issue in this general rate case. The Schedule 93 surcharge is required to be "zeroed

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[203] Norwood, KON-1T at 30:13-14.

[204] Parvinen, MPP-1T at 14:15 – 15:2.

[205] Norwood, KON-1T at 30:20 – 31:10.

[206] Woodruff, KDW-1T at 5:3-7.

[207] ICNU Brief, ¶ 4.

out" when the deferral balance is eliminated.[208] We note that this is expected to happen in the next several months. Reducing the level of the surcharge prior to that point in time would offer rate relief during this difficult winter, in return for extending the surcharge at a lower level for some period of time.

174 We see value in the Company providing its customers with rate relief when it can, and we are sympathetic to ICNU's preference for one modification to rates this winter, rather than two. Nevertheless, the Schedule 93 tariff is not properly before us in this proceeding and the matter of the ERM surcharge is not relevant to the question of whether the tariffs that are before us yield rates that are fair, just, reasonable and sufficient. The Company can choose its own time for filing a modification to Schedule 93, consistent with requirements of our order initially approving the tariff.

D. Contested Issues – Lancaster Generation Facility

1. Positions of the Parties

175 *The Company's Proposal.* The Company seeks to recover in rates the costs associated with operation of the Lancaster Generating Facility, which is a 245 MW natural gas-fired combined-cycle combustion turbine (CCCT) plant located in Rathdrum, Idaho. Although the Company does not have an executed agreement regarding the plant's operation, it intends to obtain the rights to operate this facility under a "tolling agreement" with Avista Turbine Power (Avista Turbine), a wholly-owned subsidiary of Avista Corporation. The Company affirms that the power supply expense included in the Partial Settlement Stipulation (which decreases test year NOI by $6,904,000 and increases revenue requirement by $11,101,000) includes the Lancaster generation plant expenses and revenues.[209] The Company also requests that we find prudent its arrangement with Avista Turbine.[210]

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[208] *2001 Avista Rate Case Order*; Settlement at 7-8 ("At the point in time when the Energy Cost Deferral Balance reaches zero, the Schedule 93 surcharge tariff will be eliminated. . .").

[209] Johnson, TR. 922:1-9. *See also* Exh. RLS-6 at 13, which discusses the impact of the Lancaster contracts on the Company's revenue requirement. According to Table 10, there is a $12.9 million impact on revenue requirement for the 2010 rate year.

[210] Storro, Exh. RLS-1T at 8:13 – 9:8 and 16:13-26. *See also* Exh. RLS-3 for a map of the Lancaster Generating Facility's location and a picture of the plant.

176 The Company's understanding with Avista Turbine for the control of the Lancaster facility requires review of the existing contracts between Avista Turbine and Coral Energy. These contracts consist of the Lancaster power purchase agreement (PPA), two transmission contracts, and three agreements for gas transportation from two delivery points, Alberta and Malin. By way of the power cost element of the Partial Settlement Stipulation discussed above, the Company also requests recovery of the cost of natural gas to be purchased as fuel for the Lancaster plant.

177 Avista explains that under the anticipated Lancaster PPA, it would have rights to dispatch Lancaster beginning January 1, 2010, and retain those rights through October 31, 2026.[211] As part of the transaction in which Avista Utilities would obtain control of the plant's output, the Company would be responsible for procuring and arranging transport of natural gas fuel to the plant and arranging the subsequent transmission of electric power from the plant.[212]

178 The Lancaster plant is currently interconnected to the Bonneville Power Administration (BPA) transmission system.[213] Avista Corporation now holds (in the name of Avista Energy) two transmission agreements for a total of 250 MW of long-term firm transmission capacity from the Lancaster plant to BPA facilities at the John Day dam. These agreements are temporarily assigned to Coral Energy, and would be permanently assigned to Avista Utilities after January 1, 2010.[214] Avista Corporation expressed its intent to rely on these transmission rights while evaluating a direct interconnection between the Lancaster plant and the Company's own transmission system.[215] The Company says it is in the process of jointly studying with BPA the

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[211] Storro, Exh. RLS-1T at 10:4-6.

[212] *Id.* at 10:6-9.

[213] *Id.* at 10:19-20.

[214] *Id.* at 10:20 – 11:2.

[215] *Id.* at 11:2-3. *See also* Storro, TR. 775:14-16 (observing that the plant is within 300 feet of Avista Corporation's own transmission network).

prospect of interconnecting its transmission to BPA's Lancaster substation and this process is expected to take a minimum of two years.[216]

179 The Lancaster plant is also interconnected to the Gas Transmission Northwest (GTN) pipeline system.[217] On January 1, 2010, Avista Utilities would receive permanent assignment of firm natural gas transport rights on the TransCanada Alberta and TransCanada B.C. systems and temporary assignment of firm gas transport rights on the GTN system. These contracts provide access to three different natural gas hubs: AECO (via TransCanada) and Malin or Stanfield (via GTN),[218] but terminate on October 31, 2017.[219]

180 The Company relies on a White Paper[220] and two studies to support its assertion that utility acquisition of the Lancaster contracts would be prudent:[221]

- Lancaster Generating Facility Power Purchase Agreement Evaluation Overview (Evaluation Overview Study) completed on April 11, 2007, and
- Thorndike Landing Study (TL Study) performed by an independent evaluator and completed on October 30, 2007.

181 The Company's own Evaluation Overview Study concludes that the Lancaster contracts were more cost-effective than building a new "greenfield" plant and also a better option than a "brownfield" project.[222] According to the Company, the

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[216] Lafferty, Exh. RJL-1T at 4.

[217] Storro, Exh. RLS-1T at 10:10-11.

[218] *Id.* at 10:15-18.

[219] *Id.* at 10:11-18.

[220] The White Paper, completed on November 2, 2007, summarizes two other studies completed earlier in 2007 and described more fully below. The White Paper is contained in Exh. RLS-6.

[221] Storro, Exh. RLS-1T at 11:4 – 14:10 and 15:8 – 17:2; the Company's internal Evaluation Overview Study is contained in Exh. RLS-4. Thorndike Landing's "Independent Valuation of Lancaster Facility Tolling Agreement" is contained in Exh. RLS-5.

[222] Storro, Exh. RLS-1T at 12:3-8. The Company indicates it has not been able to identify any brownfield projects with a cost approximating $550 per installed kW.

independent TL Study used several different valuation methods and concluded that the Lancaster PPA was financially favorable relative to other natural gas fired options in the Northwest.[223]

182 Based on these studies, subsequent observations of market transactions and the need for capacity referenced in its 2007 IRP, the Company asserts that acquisition of the Lancaster PPA and the associated transmission and gas transport contracts by Avista Utilities would be prudent.[224]

183 *Public Counsel's Opposition.* Public Counsel opposes the Company's request to include the Lancaster contracts in 2010 rates and advances three separate arguments.[225] First, Public Counsel contends that the Company's decision to assign the Lancaster contracts to Avista Utilities did not comply with the various prudence and other criteria established by the Commission.[226] Second, Public Counsel argues the Commission should reject assignment of any of the Lancaster contracts to Avista Utilities for calendar year 2010 because the Company has not shown a capacity need for the plant in that year, and short term energy purchases may be less expensive.[227] Third, Public Counsel recommends the Commission either entirely reject the Lancaster contracts or only allow assignment of the Lancaster PPA to Avista Utilities beginning in 2011, along with 80 percent of the gas transportation contract's cost and capacity, rejecting as unnecessary for the Company's needs the assignment of the BPA transmission contracts and the remaining 20 percent of the gas transportation contracts.[228] Public Counsel points out that the Company's own studies show that the

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[223] *Id.* at 12:20 – 16:12. The TL Study assumed that the output from Lancaster could be interconnected to the Avista transmission system and that the BPA transmission rights would be remarketed or otherwise optimized. *Id.* at 13:3-4.

[224] *Id.* at 16:13-17.

[225] Woodruff, Exh. KDW-1T at 3:1-13 and 5:14 – 35:11.

[226] *Id.* at 8:8 – 12:13. Public Counsel takes the position that each of the three Lancaster contracts is severable and should have been separately valued by the Company. *See* Public Counsel Brief, ¶ 98.

[227] Woodruff, Exh. KDW-1T at 12:14 – 16:10 and 33:13 – 34:11.

[228] *Id.* at 16:11 – 17:12 and 28:12 – 33:12. *See also* Public Counsel Brief, ¶ 148.

Lancaster Contracts would increase power cost expense by approximately $18 million on a system basis in 2010.[229]

184 Public Counsel also asserts that in the settlement stipulation establishing Avista's Energy Recovery Mechanism (ERM),[230] the Company agreed not to enter into electric or natural gas commodity transactions with Avista Energy until the Energy Cost Deferral Balance (ECDB) falls to zero or Avista obtains agreement from all settling parties in relevant prior dockets.[231] Public Counsel contends that the Lancaster PPA transaction is a "commodity transaction" under any reasonable interpretation of that term as used in the ERM Settlement agreement."[232]

185 In addition, Public Counsel points out that assignment of the Lancaster contracts from Avista Turbine to Avista Utilities would be an affiliate transaction and Avista did not cite any affiliate transaction rules as applicable to this proposal.[233] It asserts that without a "market test" to determine what other resources were available to the Company, the Commission does not have sufficient information to draw conclusions regarding the reasonableness or prudence of the Lancaster contracts.[234] Further, Public Counsel contends that Avista's failure to issue a request for proposals (RFP) to

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[229] Public Counsel Brief, ¶ 122.

[230] *See 2001 Avista Rate Case Order*, Appendix B. At page 7 of the Settlement, Section 4.e states: "Transactions with Avista Energy: The Company agrees that it will not enter into any electric or natural gas commodity transactions with Avista Energy related 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."

[231] Woodruff, Exh. KDW-1T at 11:3-22. *See also* Public Counsel Brief, ¶¶ 108-114. ICNU did not file testimony on the Lancaster contracts, but it raises an identical concern in its Brief at ¶ 14.

[232] Public Counsel Brief, ¶ 110.

[233] Woodruff, Exh. KDW-1T at 5:16 – 7:16 and 10:10-24. *See also* Public Counsel Brief, ¶¶ 105-106 and ICNU Brief, ¶ 11.

[234] Woodruff, Exh. KDW-1T at 12:1-3; Public Counsel cites to the "lower of cost or market" standard set out in the Commission's decision in *UTC v. Avista Corporation*, Docket No. UG-021584, Sixth Supplemental Order Rejecting Benchmark Mechanism Tariff, ¶ 32 (Feb. 13, 2004).

meet the power capacity need identified in its 2007 Integrated Resource Plan (IRP) appears to violate the requirements of WAC 480-107.[235]

186 Noting that the pro forma power supply adjustment agreed to in the Partial Settlement Stipulation includes Lancaster costs, Public Counsel recommends a further adjustment to remove costs associated with the Lancaster contracts from the rate year. Public Counsel's recommended adjustment to power cost increases NOI by $779,000.[236]

187 *Company Response to Public Counsel.* In reaction to Public Counsel's challenges, the Company asserts that the Lancaster contracts are not above-market and provides a table of levelized costs of comparable Northwest CCCTs that recently have been sold.[237] The Company also disagrees with Public Counsel's claim that the Lancaster contracts were acquired too early, countering that resources are often "lumpy" and rarely come into service on a schedule that perfectly meets a Company's needs.[238] Further, the Company disagrees with Public Counsel's assertion that an RFP was required because it interprets the rule to mandate issuance of an RFP only if a resource deficit is projected to occur within three years of the publication of the IRP.[239]

188 The Company also opposes Public Counsel's adjustment to remove the cost of the Lancaster PPA for the year 2010, claiming that the plant is cost-effective over the life of the plant.[240] Asserting that a prudence determination should be based on information available at the time of the decision, the Company also asserts that the

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[235] Woodruff, Exh. KDW-1T at 12:9-13. *See also* Public Counsel Brief, ¶ 107.

[236] Exh. B-5, Electric Schedules, Revised (Oct. 19, 2009), at Tab A-1, column AH.

[237] Kalich, Exh. CGK-4T at 2:7-10.

[238] *Id.* at 3:1-5.

[239] *Id.* at 8:16-20.

[240] *Id.* at 1:21 – 4:21.

average post-Lancaster project costs are more than twice the cost of Lancaster if other plant costs are adjusted to 2010 dollars.[241]

189 The Company opposes Public Counsel's proposed adjustment to remove the costs of the BPA transmission contracts for the year 2010 asserting instead that they are essential for the Lancaster plant.[242] It points out that the assumption as to remarketing three-quarters of its transmission capacity was based on the long-term operation of the plant.[243] The Company describes the recovery of transmission costs as an assumption entered into the financial models.[244] As a result, its projected revenues for the remarketing of BPA transmission reflected in the power cost rates in the Partial Settlement are also assumptions.[245] Although Lancaster has been operated by Avista Turbine since 1999,[246] it has just begun the process of interconnecting the plant to Avista's transmission system.[247]

190 The Company also opposes Public Counsel's adjustment to remove 20 percent of the costs of the gas transport contracts asserting that the extra capacity would be used to help meet the utility's peak needs when it runs the Lancaster and Coyote Springs 2 plants simultaneously.[248] The Company reveals that it does not have enough long-term firm gas transport capacity to operate both plants at full capacity and will have to

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[241] *Id.* at 12:5-12.

[242] The Company describes the Lancaster contracts as having two BPA transmission contracts: one that can be terminated on two years notice and one that cannot be terminated. The Company also indicates the two BPA contracts are insufficient to deliver the Lancaster plant's full output capacity and that the Company will purchase non-firm transmission to deliver the additional output above 250 MW. *See* Lafferty, Exh. RJL-1T at 2:10-12 and 3:1-3.

[243] Storro, Exh. RLS-4T at 3.

[244] Storro, TR. 780:5-21.

[245] *Id.* at 868:2-8.

[246] *Id.* at 797:16-17.

[247] Lafferty, TR. 905:11 – 906:3; *see also* Exh. RJL-2-X.

[248] Lafferty, Exh. RJL-1T at 6:1-4.

buy additional capacity.[249] It asserts that were the Commission to disallow all or a portion of the costs associated with the transmission or gas transport contracts as suggested by Public Counsel, the Company would need to examine other alternatives for Lancaster, rather than dedicating it for the benefit of its ratepayers.[250]

191 As to the circumstances Avista Corporation faced when it secured the facility and transferred its rights to Avista Turbine, Avista Utilities emphasizes the very limited window of opportunity within which Avista Corporation could act, given the pending sale of Avista Energy.[251] It states that there was neither time nor the requirement to obtain a formal RFP.[252] It argues further that the Lancaster contracts were the lowest cost resources at the time of the decision, April of 2007,[253] and without Lancaster it would need to build a CCCT plant to serve its load at a cost premium of 50 percent or more, which would not be in its customers' long-term interests.[254]

192 At hearing the Company revealed under questioning from the bench that Avista Turbine holds the long-term rights to the Lancaster contracts and that there is no written agreement between Avista Utilities and Avista Turbine regarding the transfer, sale or assignment of the Lancaster contracts.[255] Nor, according to the Company, would there be such a transfer should the Commission reject the Company's proposed rate treatment. During the proceeding and in written testimony, it insisted that Lancaster would only be transferred to the utility when and if the Commission

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[249] *Id.*

[250] Kalich, Exh. CGK-4T at 16:9-11.

[251] Avista Brief , ¶ 37 [emphasis in original].

[252] *Id.*

[253] *Id.*, ¶ 48.

[254] Kalich, Exh. CGK-4T at 18:11-13.

[255] Storro, TR. 817:22-24. While the Company testified that the transaction was between two affiliated corporations, it was only after the evidentiary hearing that it conceded that the proposed transaction constitutes an affiliated transaction and is therefore governed by the Commission's principle that the costs of affiliated interest transactions are reflected in rates at the lower of market or cost. *See* Avista Brief, ¶ 45, n.15.

approves recovery of its future costs.[256] If the Commission did not allow all Lancaster costs into rates, then Avista Turbine would explore other transfer or sale opportunities that better reward the shareholders of Avista Corporation.[257]

193 *Position of Staff at Hearing.* Staff did not pre-file responsive testimony regarding the Lancaster contracts. At hearing, however, Staff voiced its support for a finding of prudence for the Lancaster contracts.[258] Staff opined that acquisition of the Lancaster tolling agreement would not violate the ERM settlement agreement because the tolling agreement is not a commodity.[259] However, Staff agreed that the Lancaster contracts are affiliate transactions.[260] Staff witness Alan Buckley indicates that the fact that Lancaster was a low-cost resource compared to other natural gas plants in the region "overrode" in his mind the considerations of the affiliate interest statute that are designed to protect the ratepayer.[261] Staff testified that it believes the issuing of an RFP to compare the Lancaster contracts to bids from an RFP would not have changed Staff's ultimate conclusion.[262]

194 Staff based its opinion regarding prudence on (1) a balance of interests between the Company's shareholders and ratepayers, (2) the long-term effect on rates rather than the effect today, (3) the administrative burden of analyzing market transactions to meet resource needs versus long term contracts (4) the qualitative comparison of other similar transactions in the market place and (5) analysis of the cost and attributes of other similar natural gas plants reviewed recently by the Commission.[263] However,

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[256] The "regulatory out clause" became a repetitive theme for the Company. *See* Avista Brief, ¶¶ 22, 32, 37, 42 (twice), ¶ 43 (four times), ¶ 44 (twice), ¶ 45, and ¶ 55. *See also* Kalich, CGK-4T at 16:9-11 and Storro, TR. 815:23 – 818:18.

[257] Storro, TR. 777:1 – 778:24.

[258] Buckley, TR. 939:24-25.

[259] *Id.* at 942:5-17.

[260] *Id.* at 945:9-13.

[261] *Id.* at 945:19 – 946:9.

[262] *Id.* at 957:20-23.

[263] *Id.* at 948:3 – 950:14; Staff Brief, ¶ 74.

Staff testified it was a surprise to discover that there was no contract between Avista Utilities and Avista Turbine to transfer the Lancaster contracts.[264]

195 Staff reiterates its position in support of the prudence of the Lancaster contracts on briefing.[265] Staff concludes that the presence or absence of a contract between Avista Utilities and Avista Turbine is not determinative because Avista Corporation, the parent corporation, has a duty to both its ratepayers and its shareholders and there is no guarantee that the Corporation would hold off on perhaps dealing with another utility in order to save the Lancaster contracts for Avista Utilities in 2011.[266] Staff explains its position on the ERM settlement prohibition on "commodity transactions" as applying to hourly, secondary market purchases, not to the acquisition of the full operating rights of a large power plant.[267] Staff also agrees with the Company that the acquisition "should" meet the affiliate transaction standard of lower of cost or market and cites to five pages of Company testimony in support of its conclusion.[268]

196 *ICNU.* ICNU recommends that the Commission should adopt a result on Lancaster that provides the most benefits to customers, while sending a message to Avista that ignoring the rules applicable to affiliate transactions will not be tolerated.[269]

197 ICNU asserts that when Avista knew in 2007 it intended to assign the Lancaster tolling agreement to Avista Utilities, it should have filed an affiliate interest application with the Commission seeking approval of the transfer pursuant to RCW 80.16.020. ICNU describes a similar incident in a 1999 rate case in which Avista failed to file for approval of an affiliate interest transaction and instead filed

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[264] Buckley, TR. 946:6-15.

[265] *Id.*, ¶ 73.

[266] *Id.*, ¶ 75.

[267] *Id.*, ¶ 76.

[268] *Id.*, ¶ 77.

[269] ICNU Brief, ¶ 15.

for recovery in a general rate case without ever acknowledging the affiliate nature of the transaction.[270]

198 ICNU also notes that there is no evidence of record that Avista Utilities tried to negotiate a later start date of 2011 for the Lancaster contracts.[271]

2. Compliance with Emissions Performance Standard

199 In response to questions posed from the Bench during and subsequent to the evidentiary hearing, the Company says it believes that the Lancaster PPA must comply with the Greenhouse Gases Emissions Performance Standard (EPS) established in RCW 80.80.[272] In further response to our questions, and despite the fact that it filed no request in its direct or rebuttal cases, it seeks our determination in this proceeding that the Lancaster arrangement will comply with the EPS.[273] The Company points to elements of evidence here and there in our record that it asserts will carry its burden to demonstrate compliance with the standard. This evidence includes an air permit issued by the state of Idaho the Company offers subsequent to the evidentiary hearing as an attachment to our bench request.[274] Avista asserts that evidence of record demonstrates that the greenhouse gas emissions related to the Lancaster PPA are 810 pounds of CO_2 per MWH, well below the standard of 1,100 pounds.[275]

200 Staff argues that the EPS standard does not apply because the requirements imposed by RCW 80.80 only apply to power supply contracts entered into after June 30, 2008. According to Staff, the record shows that "Avista Utilities, through its affiliates (subsidiaries), has continuously held the capacity and electric rights under the

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[270] *Id.*, ¶¶ 12, 13.

[271] *Id.*, ¶ 13.

[272] Norwood, TR. 1083:10 – 1086:8.

[273] Exh. B-13 (supplemental response, October 15, 2009) and Avista Brief, ¶ 31.

[274] Exh. B-14 (response to Bench Request No. 13, October 13, 2009).

[275] Avista Brief, ¶ 31.

Lancaster PPA since 1998, with the exception of the limited term when those rights were assigned to Coral, with reversionary rights to Avista Utilities (through Avista Turbine) in 2010."[276]

201 Public Counsel and the Northwest Energy Coalition say that the provisions of RCW 80.80 do apply to the Lancaster PPA. Public Counsel contends that prior to July 1, 2008, the Lancaster PPA was held by an unregulated subsidiary and that the "utility does not acquire the rights to the power, if at all, until January 1, 2010."[277]

202 Avista argues that the information it points to in the record is sufficient and that the "sensible" approach is for the Commission to make the determination it requests in this proceeding.[278]

3. Commission Decision

203 The Lancaster matter is extraordinary. Our record contains evidence and argument that demonstrate sharp disagreement regarding whether the Lancaster contracts are a prudent and cost-effective resource to include in customer rates. However, those issues of fact and perspective are not what make the matter extraordinary. Lancaster is extraordinary for what is *not* in our record, and for the unique way in which the Company presented the matter to us.[279]

204 The Company seeks a prudence determination and recovery in customer rates for a power contract that it has not provided to the Commission for the record in this case.

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[276] Exh. B-16 (response to Bench Request No. 12, October 14, 2009).

[277] Exh. B-15 (NWEC response to Bench Request No. 12, October 14, 2009) and Exh. B-18 (Public Counsel response to Bench Request No. 12, October 15, 2009).

[278] Avista Brief, ¶ 31.

[279] A utility's initial filing in a general rate case must contain the maximum amount of information then available to the company. Staff, Public Counsel, and intervening parties cannot always thoroughly investigate and vet new information and figures submitted later in the proceeding. We recognize that some data and figures will be subject to updating or supplementation, but the evidentiary crucible of the rate case proceeding is deprived of its effectiveness if key facts and positions are not contained in the initial filing.

Indeed, during the hearing, it conceded that the contract had not been executed.[280] The Company concedes that the PPA that has been anticipated since 2007 would be a transaction with an affiliated interest,[281] yet our record contains no affiliated interest filing with which to determine compliance with the requirements of RCW 80.16.020 and our rule, WAC 480-100-245, regarding such transactions.

205 Further, the Company concedes that the anticipated power purchase arrangement must comply with the greenhouse gases emissions performance standards set out in RCW 80.80 and our rules at WAC 480-100-405 through -435, yet it filed no request for a determination in its direct or rebuttal cases.[282] It requests our approval without having filed a comprehensive presentation of evidence adequate for the parties to examine and for us ultimately to determine whether the standard applies and, if it does, if the anticipated PPA would comply.

206 Finally, the Company presents us with the proposed PPA as an ultimatum – it will execute the agreement only if we approve the ratemaking treatment requested as a condition precedent.

207 These are not mere technical deficiencies in the Company's case. They constitute failure on the part of the Company to bring a matter properly before us. Accordingly, we need not (indeed, cannot) reach the related issues of whether the Lancaster PPA acquisition is prudent and whether its associated costs can be put in rates because the issues are not properly before us. Furthermore, the Company's tone is troublesome. In effect, the Company suggests we take a "trust us" approach. However, we require more than trust to support a rate filing. Regulated utilities carry the burden of

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[280] Storro, TR. 817:22-24. Subsequent to the hearing, and after the close of the record and the completion of briefing, the Company provided a copy of an agreement dated December 7, 2009, for the sale of the output of the Lancaster facility. From the face of the cover letter, it was unclear whether the Company intended to file the contract in this rate case docket or in a new docket seeking approval of an affiliated interest arrangement. Accordingly, the Commission sought clarification through a letter from the Executive Director and Secretary of the Commission. The Company responded on December 11, 2009, that it did *not* intend to file the contract in this rate case docket, but only in a new affiliated interest proceeding.

[281] Storro, TR. 810: 2-16; Avista Brief, ¶ 45, n.15.

[282] Exh. B-13.

demonstrating that the rates they propose will be fair, just, reasonable and sufficient.[283] The Legislature enacted these various requirements for sound policy reasons and required us to enforce them. We do so here. We cannot approve the Company's request to find the Lancaster contracts prudent and the associated costs put into rates for the following three reasons.

208 First, although there is no dispute that the Company has consistently stated its intent to acquire rights to control and operate the Lancaster plant, the fact remains that there is no contract before us.[284] Avista made this decision in early April 2007, following an internal evaluation, but prior to the public announcement regarding the sale of Avista Energy.[285] Shortly thereafter, Avista communicated this decision to its investors via its 2007 Annual Report.[286] Nevertheless, the Company did *not* file a contract reflecting this intent with the Commission at any time during 2007 or 2008. Further, the Company never submitted an executed contract between Avista Utilities and Avista Turbine as part of its filings in this proceeding.[287]

209 In its brief, the Company characterizes the lack of a contract for the transfer of the Lancaster contracts as a matter of "housekeeping" and easily cured by its own internal "ministerial act."[288] In a self-serving statement regarding the significance of the fact that there is no contract in the record regarding any commitment between Avista

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[283] RCW 80.28. 020.

[284] Avista Brief, ¶ 42.

[285] *See* Exh. RLS-4; Avista Brief, ¶¶ 32 and 37; and Exh. RLS-19-X.

[286] *See* Exh. KDW-7, at 2-3 (corresponding to pages 14-15 of the Annual Report). We note that Avista stated not only its firm intent for Avista Energy to contract for the Lancaster PPA from 2010 through 2026, but also its recognition that the rights associated with the PPA could not be transferred to the regulated utility until it obtained future approval from this Commission and the Idaho Public Utilities Commission.

[287] *See* Exh. RLS-22-X (response acknowledges the lack of written documentation regarding the Company's obligations to purchase power from the Lancaster plant). To the best of our knowledge, the Company's only filing with the Commission of a Lancaster contract occurred on Tuesday, December 8, 2009. On Friday, December 11, 2009, the Company clarified that its filing was intended as a new affiliated interest proceeding, not as a supplement to these dockets.

[288] Avista Brief, ¶ 43.

Turbine and the Company regarding the Lancaster plant, the Company's Brief provides that "the short answer to Chairman Goltz's question is that the absence of such a contract to reassign the PPA to Avista Utilities <u>does not matter</u>."[289] We disagree. Moreover, we are surprised that the Company apparently fails to recognize the importance of providing the Commission with the executed terms and conditions of a contract it asks us to approve. Without the contract, the Company cannot carry its burden of proof. In other words, the contract *does* matter.

210 Second, RCW 80.16.020 requires the Company to file with the Commission a copy of nearly any contract or arrangement it enters with an affiliated interest. The language is expansive:

> Every public service company shall file with the commission a verified copy, or a verified summary if unwritten, of a contract or arrangement providing for the furnishing of management, supervisory[,] construction, engineering, accounting, legal, financial, or similar services, or any contract or arrangement for the purchase, sale, lease, or exchange of any property, right, or thing, or for the furnishing of any service, property, right, or thing, other than those enumerated in this section, hereafter made or entered into between a public service company and any affiliated interest as defined in this chapter . . . .

211 The filing must be made prior to the effective date of the contract and thereafter the Commission is empowered to investigate and disapprove the contract if the Company fails to prove the contract is reasonable and consistent with the public interest.

212 There is no dispute that Avista Turbine is an affiliated interest of Avista Utilities. Further, there is no dispute that the Company had settled on its arrangement to obtain dispatch control of and power from the Lancaster plant approximately 2 ½ years in advance of the desired January 1, 2010, effective date of a contract. The Company has made clear that it understood its obligations to make an affiliated interest filing with regard to the Lancaster contracts.[290] Nonetheless, no such filing is part of our

[289] Avista Brief, ¶ 44 (emphasis added); *see also* ¶ 41 referencing Chairman Goltz's question posed at hearing.

[290] *See* Avista Brief, ¶ 45, n.15.

record. As a result, we see no regulatory route or method that would enable us to satisfy our statutory duties to evaluate this affiliated transaction.[291]

213 If the Company's original filing in January 2009 had included the required affiliated interest submissions, we have no doubt that the parties to this case would have created a sufficient record on which we could enter our determination. For reasons not explained, the Company failed to timely make the required filing that might have allowed us to grant the relief it seeks.

214 This is particularly puzzling given that this is not Avista's first experience handling an affiliated interest filing. In 1999, the Company failed to provide notice in its case in chief of an affiliated transaction with Spokane Energy, LLC, one of its subsidiaries. In that matter, the Company repeatedly asserted that it was not required to file or even notify the Commission of its arrangements with an affiliated interest. Although we ordered the Company to promptly make the required filing, we refrained from penalizing the Company for its omissions.[292] Accordingly, because of the lack of any affiliated interest approval, we cannot reach the issues Avista seeks to put before us.

215 Third, we cannot approve the costs of the Lancaster facility in Avista's rates because we need to make a decision whether it complies with RCW 80.80, and we cannot do so on this record.

216 All baseload electric resources built or acquired by utilities after June 30, 2008, and all baseload power purchase agreements of longer than five year duration entered into by utilities after June 30, 2008, must comply with the greenhouse gases emissions

[291] The Company not only failed to present us with the actual terms and conditions of its agreement; it also failed to support its representations as to the potential agreement's costs. Again, we are asked to take it on faith that the unspecified terms will reflect the costs actually paid by Avista Turbine. Furthermore, the Company did not support its market analysis with other PPAs that may be available to it for the same period. Instead, its market analysis relied solely on the cost of power plants sold in the region with full ownership rights. While not quite an "apples to oranges" comparison, the difference between a tolling agreement and actual ownership could have a significant impact on costs.

[292] *1999 Avista Rate Case Order*, ¶¶ 67-70.

performance standard of 1,100 pounds per MWH set out in RCW 80.80.[293] The statute imposes on us the responsibility to ensure that new electrical company power supply resources comply with this standard.[294]

217 This statute requires the Commission to first determine whether a new power resource is "baseload electric generation" – defined by statute as a resource that operates with a capacity factor of no less than 60 percent.[295] If the resource is not baseload electric generation, the requirements of RCW 80.80 do not apply and electrical companies do not receive certain special rights regarding cost deferral granted by the statute.[296] Our responsibility in this area is a new one, and we take it very seriously. We are especially mindful of the first cases we are obligated to address under this statute in order to ensure that a deliberate and thorough process is established for future cases.

218 The Commission shares the responsibility for regulating compliance with the EPS with the Department of Ecology (WDOE) and the Energy Facility Site Evaluation Council (EFSEC) for power plants located within the borders of Washington, to the degree these agencies must condition permits under their jurisdiction on compliance with the standard.[297] But, in the instance of an out-of-state power plant (or contract for power supply from an out-of-state power plant), we are the sole agency with EPS enforcement authority over electrical companies because the EFSEC and WDOE have no permitting jurisdiction over out-of-state facilities. This fact underscores the importance we place on our responsibility in these circumstances. The proposed Lancaster PPA is just such a circumstance.

219 If a new power resource is "baseload electric generation," then the statute describes two alternate methods by which the Commission may approve any "long-term financial commitment" for such a resource. The relevant portions of RCW 80.80.060 are as follows:

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[293] RCW 80.80.040.

[294] RCW 80.80.060(2).

[295] RCW 80.80.060(3).

[296] RCW 80.80.060(6).

[297] RCW 80.80.040(13).

> (1) No electrical company may enter into a long-term financial commitment unless the baseload electric generation supplied under such a long-term financial commitment complies with the greenhouse gases [gas] emissions performance standard established under RCW 80.80.040.
>
> (2) In order to enforce the requirements of this chapter, the commission shall review in a general rate case or as provided in subsection (5) of this section any long-term financial commitment entered into by an electrical company after June 30, 2008, to determine whether the baseload electric generation to be supplied under that long-term financial commitment complies with the greenhouse gases [gas] emissions performance standard established under RCW 80.80.040.
>
> (5) Upon application by an electrical company, the commission shall determine whether the company's proposed decision to acquire electric generation or enter into a power purchase agreement for electricity complies with the greenhouse gases [gas] emissions performance standard established under RCW 80.80.040. The commission shall not decide in a proceeding under this subsection (5) issues involving the actual costs to construct and operate the selected resource, cost recovery, or other issues reserved by the commission for decision in a general rate case or other proceeding for recovery of the resource or contract costs.

220 The first of the two methods is discussed in subsection (2), quoted above. That allows the Commission to review "in a general rate case" a "long-term financial commitment entered into" by the Company after June 30, 2008. Because the Lancaster PPA was not entered into prior to the rate case, subsection (2) cannot apply. The second way is discussed in subsection (5). That allows review by the Commission of a "proposed decision" to "enter into a power purchase agreement." But if that statutory route is chosen, the statute prohibits the Commission from deciding in that proceeding "issues involving the actual costs to construct and operate the selected resource, cost recovery, or other issues reserved by the commission for decision in a general rate case." So, neither option works for Avista. Indeed, the statute simply prohibits the Commission from considering the matter of a *proposed* agreement in this case.

221 In this proceeding we are presented by Avista with an eleventh hour request that we in effect "mine the record," in lieu of the Company making its own organized presentation, to satisfy ourselves that sufficient information is present for us to find that its proposed Lancaster acquisition would comply with the EPS. As we consider this unusual request, we are mindful of three important points. First, WAC 480-100 clearly places the burden on the Company to demonstrate that a new power acquisition complies with the EPS.[298] Second, while the Company points us to elements of evidence scattered through our record that it claims satisfy the requirements of our rules, our staff and the other Parties have not had the opportunity to examine and test this evidence for the purpose to which it is now put by the Company. Third, the Company is asking us to exercise for the first time an important and new responsibility regarding contracts for out-of-state power supply in a last minute and ad hoc manner.

222 We contrast this situation with our recent proceeding regarding PacifiCorp's acquisition of a new in-state power resource, the Chehalis generating plant.[299] In that proceeding, we considered an organized company presentation and a thorough Staff analysis before making an EPS determination. In this proceeding we have neither, yet the Company urges us to act because it says to do so would be "sensible."

223 Our record evidence, in the unorganized and ad hoc manner the Company has presented it, leaves us unable to conclude that the EPS even applies in this instance. This is a threshold issue. The Company has not demonstrated and we are not able to conclude with certainty from our own evaluation that the proposed Lancaster PPA qualifies as "baseload electric generation." Moreover, Staff has raised legitimate questions about the application of RCW 80.80 in the context of serial ownership and a complicated transaction with an affiliate of the electrical company. Finally, as to compliance with the EPS, if it applies at all, the heat-rate data and Idaho air permit data the Company commend to our attention is useful, but insufficient without

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[298] WAC 480-100-405, "Electrical companies bear the burden to prove compliance with the greenhouse gases emissions performance standard under the requirements of WAC 480-100-415 or as part of a general rate case."

[299] *UTC v. PacifiCorp*, Docket UE-090205, Order 09, *Final Order Approving and Adopting Settlement Stipulation* (Dec 16, 2009).

supporting analysis and corroborating engineering testimony. In general, technical data, such as this, must be presented or supported by an expert witness and subject to cross-examination before we can find it to be relevant and reliable. Accordingly, we cannot approve at this time Avista's request under RCW 80.80.

224 *The Company's Ultimatum is Tantamount to Making the Commission a Contract Party.* We are also concerned with the framing of the issue in the form of an ultimatum to the Commission: if you do not approve this arrangement that you do not have before you and for which there have been no affiliated interest or RCW 80.80 filings, we will not enter into the agreement even though it is of great benefit to the ratepayers.

225 The Commission considered a "regulatory out clause" in a 2004 proceeding involving Puget Sound Energy's contract for purchase of a power plant from a third party.[300] In that matter, given the facts of the transaction in question, we concluded that the contract was not contrary to the public interest. However the case before us presents significantly different facts. First, the arrangement at issue here is a contract with an affiliated interest, not a third party. The contracting parties are in a practical sense representing the same interest. Second, the "regulatory out clause" in our prior case was bilateral, optional, and related only to our approval of the power plant acquisition, not any specific ratemaking treatment. In the present case, the Company says it intends to enter a contract that can be "unwound" if the "appropriate ratemaking treatment" is not approved.[301] We do not have to reach a decision about the appropriateness of the "regulatory out" language in the contract, as it is not even in the record, and, as described above, there are other prerequisites as well.

226 In sum, in this case, we do not authorize the Company to recover in rates any costs associated with the Lancaster facility. We conclude that the Lancaster contracts cannot be included in 2010 rates and must be removed from the Company's power

[300] *UTC v. Puget Sound Energy, Inc.,* Docket No. UE-031725, Order 12, *Granting Regulatory Approvals for Frederickson I Acquisition; Resolving Disputed Gas Price Issue* (April 7, 2004).

[301] Avista Brief, ¶ 43. The Company's claim that following any undesirable ratemaking treatment from the Commission it would simply "unwind" any contract it makes with its affiliate Avista Turbine Power raises the question of why such a contract wasn't signed long ago.

costs included in the Settlement Agreement. We adopt Public Counsel's adjustment to pro forma power supply that increases test period NOI by $779,000 to accomplish this result. We require the adjustment to be revised by the compliance we require. Avista must make a compliance filing to revise the pro forma power supply adjustment by rerunning its power supply model with all aspects of Lancaster removed and all other assumptions and inputs equivalent to those used to calculate power supply for the Partial Settlement Stipulation.[302]

227 Our decision here does nothing to prevent the Company from seeking recovery of Lancaster costs or deferred balances in the future. Without having the Company's detailed filings before us, we decline to permanently disallow the 2010 Lancaster costs or find the entire contract imprudent for its full term. We acknowledge that the Company's IRP identifies a need for new cost-effective energy and capacity resources over the next decade. Staff and the Company both represent that taking a long-term view of the Lancaster contracts suggests they may be beneficial to ratepayers. However, we cannot reach that issue and make such a conclusion at this time.

228 Notwithstanding the discussion above, because of the uniqueness of the confluence of facts and law on the Lancaster issue, we will allow the Company to defer the costs associated with the Lancaster PPA and associated contracts subject to the following requirements and limitations.[303]

229 The Company is authorized to defer, in an account separate and apart from the ERM deferral, the net costs of contracts for power supply, transmission, fuel gas transportation, and fuel gas related to the Lancaster generating facility. Any recovery

[302] In essence, this parallels what Public Counsel argues with regard to its proposed adjustment to PF-1. *See* Larkin, Exh. HL-1T at 10:3-6 and Woodruff, Exh. KDW-1T at 38 (Table 7). We note that Kalich, Exh. CGK-5-X describes on page 1 that this modeling may have already been done in response to Public Counsel Data Request 470.

[303] Of course, this assumes that the Avista will enter into the PPA. Should the Company choose otherwise, the potential Lancaster PPA may prove useful as a benchmark for evaluating the benefit of other resources the Company may acquire.

of these deferred costs in customer rates will be considered and determined in a future rate proceeding.[304]

230 The deferred accounting we authorize here is for a period not to exceed twenty-four (24) months from the beginning of the Lancaster contract; provided that if during such period the Company files in a general rate case for the recovery of Lancaster contract costs, the deferral ends on the effective date of the final decision by the Commission in that proceeding.[305] Avista must file an accounting petition specifying accounting methods and details it will use to meet the following requirements. The Company's deferral accounting must separately identify costs for the following:

- use of the Lancaster facility;
- transmission related to power supply from the Lancaster facility;
- gas transport related to the Lancaster facility; and
- fuel supply for the Lancaster facility.

The Company is authorized to accrue a carrying charge on deferral balances at the same rate applied to its ERM deferral balances (i.e., cost of debt).

231 The Company must file the Lancaster power supply and related transmission and fuel gas transport contracts once such contracts are finally executed. In conjunction with the contract filing, or in a separate filing, the Company must file evidence to demonstrate that, as an affiliated interest transaction, the contract(s) comply with the statutory requirements set out in RCW 80.16.020.

232 Finally, the Company must make a comprehensive and orderly filing of evidence necessary for us to determine whether the standard required by RCW 80.80 applies to the Lancaster contract and, if so, whether the actual performance of the Lancaster

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[304] We reject Public Counsel's original recommendation (*see* Woodruff, Exh. KDW-1T at 33:22 – 34:3 and 34:17 – 35:3) to permanently disallow Lancaster-associated power costs for the 2010 rate year *and* find the Lancaster contracts imprudent over their full term.

[305] Although our language authorizing this deferral is similar to that contained in RCW 80.80.060(6), we do not grant this authority under that statute because our record does not contain sufficient detail to allow us to rule on the plant's status under RCW 80.80.

plant complies with the standard. We expect our staff to undertake a thorough analysis of this data.

233 We look forward to an opportunity to properly evaluate the Lancaster contracts for both short-term and long-term impact on Avista's ratepayers and on the Company itself. Such an evaluation should be facilitated with the affiliated interest filing now pending before us.

234 After considering all proposed adjustments, we find Avista's NOI should be increased by $5.7 million on the electric side while reducing its electric rate base by almost $63 million. We also find Avista's NOI on the natural gas side should be increased by just over $1.6 million while reducing the corresponding rate base by just over $9.1 million. We provide the following summary tables for the convenience of the parties. *See* Table 4 (electric) and Table 5 (natural gas), on the following pages.

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TABLE 4

Restating and Pro Forma Adjustments – Electric ($000)

	NOI	Rate Base
Per Books	**68,538**	**1,053,828**
UNCONTESTED ADJUSTMENTS (from Table 2A)		
Total Uncontested Adjustments	**5,322**	**(101,633)**
CONTESTED ADJUSTMENTS – COMMISSION DECISION		
Property Taxes	(127)	-
Injuries and Damages	(56)	
Customer Deposits	(7)	(2,473)
Board Meeting Costs	15	
Power Supply(1)	799	
Prod. Property(2)	2,464	(11,360)
Labor Non-executive	(1,130)	
Labor Executive	(98)	
Capital Add. 2008	-	-
Capital Add. 2009	(599)	21,252
Capital Add. 2010	(434)	14,592
Asset Management	-	-
Information Serv.	-	-
CDA Settlement	(539)	16,819
Incentives	-	-
Insurance	(97)	-
Director's Fees	177	-
Total Contested Adjustments	**368**	**38,830**
Grand Total Adjustments	**5,690**	**(62,803)**
GRAND TOTAL	**74,228**	**991,025**

(1) Public Counsel's recommended adjustment, subject to revision based on re-run of the power supply model that we require in paragraph 226.
(2) Staff's recommended adjustment, subject to revision based on the re-run of the power supply model that we require in paragraph 104.

TABLE 5
Restating and Pro Forma Adjustments – Gas
($000)

	NOI	Rate Base
Per Books	**12,004**	**178,717**
UNCONTESTED ADJUSTMENTS (see Table 2B)		
Total Uncontested Adjustments	**1,413**	**(7,782)**
CONTESTED ADJUSTMENTS – COMMISSION DECISION		
Property Taxes	486	
Injuries and Damages	42	
Customer Deposits	(4)	(1,353)
Board Meeting Costs	4	
Labor Non-executive	(297)	
Labor Executive	(27)	
Capital Add. 2008	-	-
Capital Add. 2009	-	-
Asset Management	-	-
Incentives	-	-
Information Services	-	-
Insurance	(26)	-
Director's Fees	49	-
Total Contested Adjustments	**227**	**(1,353)**
Grand Total Adjustments	**1,640**	**(9,135)**
GRAND TOTAL	**13,644**	**169,582**

235 The consequent new revenue requirements for electric and natural gas are shown in Tables 6 and 7.

TABLE 6
Electric Revenue Requirement
Docket UE-090134

Rate Base	$991,025,000
Rate of Return	8.25 percent
NOI Revenue Requirement	$81,760,000
Adjusted NOI	$74,228,000
Difference	$7,531,000
Conversion Factor	.621953
Gross Revenue Requirement Increase (Decrease)	$12,109,000

TABLE 7
Gas Revenue Requirement
Docket UG-090135

Rate Base	$169,582,000
Rate of Return	8.25 percent
NOI Revenue Requirement	$13,991,000
Adjusted NOI	$13,644,000
Difference	$347,000
Conversion Factor	.62209
Gross Revenue Requirement Increase (Decrease)	$557,000

E. Decoupling

1. Introduction

236 As stated earlier, on April 30, 2009, Avista filed a petition to consolidate Docket UG-060518, involving its pilot natural gas decoupling mechanism, with this rate case proceeding, asking the Commission to extend the pilot program beyond its scheduled termination date of June 30, 2009. On May 15, 2009, the Commission consolidated the decoupling issue into the general rate cases (*Order 06*), and, on June 30, 2009, we granted an interim extension of Avista's existing pilot decoupling mechanism (*Order 07).* We now consider whether the program should be extended further and, if so, what form it would take and what purpose it would fulfill. We first establish the context for our decision with a general discussion of the importance placed upon conservation by Washington's policy makers, and then provide the rationale for decoupling and the Commission's consideration of that rationale in several prior proceedings.

2. Conservation Policy in Washington

237 The policy of this state promotes the advancement of conservation resources[306] and encourages the Commission to consider incentives for investment in such resources.[307] Consistent with this legislative directive, we have observed before that "promoting energy conservation is a goal that [the Commission] strongly supports."[308]

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[306] Conservation is defined in WAC 480-90-238(2)(c) as "any reduction in natural gas consumption that results from increases in the efficiency of energy use or distribution."

[307] RCW 80.28.024 states in part:

> The legislature finds and declares that the potential for meeting future energy needs through conservation measures . . . may not be realized without incentives to public and private energy utilities. The legislature therefore finds and declares that actions and incentives by state government to promote conservation . . . would be of great benefit to the citizens of this state by encouraging efficient energy use.

[308] *In Re 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*

238 Mindful of our responsibility to encourage conservation,[309] this Commission has promulgated rules governing integrated resource planning (IRP) that require natural gas companies to "meet system load with the least cost mix of natural gas supply and conservation."[310] In support of this goal, we require companies to assess all "commercially available conservation" and to "assess new policies and programs needed to obtain the conservation improvements."[311] Furthermore, we require a comparative analysis of natural gas supply options and available conservation opportunities in order to evaluate the least cost alternative.[312]

239 It is difficult to overstate the importance of conservation measures, as reflected in these statutes and rules, and in our policies. Though it remains in draft form at this time and relates to the electric sector, the Sixth Power Plan being developed by the Northwest Power and Conservation Council offers these observations concerning the importance of conservation in our region:

> In each of its power plans, the Council has found substantial amounts of conservation to be cheaper and more sustainable than many forms of additional electric-generating capability. In this Sixth Power Plan, because of higher costs of alternative generation sources, rapidly developing technology, and heightened concerns about global climate change, conservation holds an even larger potential for the region.

Associated With the Mechanism, Docket UG-060518, Order 04, Final Order Approving Decoupling Pilot Program, ¶ 10 (Feb. 1, 2007) [hereinafter *2007 Avista Pilot Decoupling Plan Order*].

[309] *See* RCW 80.28.025(1), which provides in relevant part:

> In establishing rates for each gas and electric company regulated by this chapter, the commission shall adopt policies to encourage meeting or reducing energy demand through . . . measures which improve the efficiency of energy end use.

[310] *See* WAC 480-90-238(1). IRPs generally set forth a mix of supply-side options and demand-side management (DSM) options. Demand-side management is another term for conservation.

[311] *See* WAC 480-90-238(3)(b).

[312] *See* WAC 480-90-238(3)(f). *See also* WAC 480-100-238(3)(e) for this policy's application to electric utilities.

> The Plan finds enough conservation to be available and cost-effective to meet the load growth of the region for the next 20 years.[313]

Although the final report may deviate slightly from the draft, these words clearly express the fundamental point that achieving significant conservation will remain a critically important goal for utilities in this region, including Washington, into the indefinite future.

3. The Commission's Approach to Decoupling

240 Much debate surrounds the question of how best to achieve the potential that conservation offers. In this proceeding, we must place ourselves at the center of this debate with respect to the rate mechanism known as "decoupling," which Avista implemented on a pilot basis in 2007 and as to which it now seeks authority to continue.[314] Some conservation advocates argue that such programs are essential to encourage conservation, while many ratepayer advocates argue that such programs create windfall revenues to companies and discourage consumer investment in energy efficiency.[315] We recognize there is sharp disagreement about the merits of this and other decoupling proposals and rely on our knowledge, experience and judgment to determine the appropriate role for a decoupling mechanism in regulating Avista Utilities.

241 The Commission has discussed decoupling and the principal elements of the decoupling debate in several prior proceedings. In 2005, the Commission conducted a rulemaking inquiry into the subject. After taking stakeholder comments and conducting a workshop, the Commission determined that "the wide variety of alternative approaches to decoupling make it more efficient to address these issues in

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[313] *See* Northwest Power and Conservation Council, Draft Sixth Power Plan, Sixth Power Plan Overview (Sept. 3, 2009), at 1 (Summary Section) (available at www.northwestcouncil.org). We take official notice of this document in accordance with WAC 480-07-495(2).

[314] *See 2007 Avista Pilot Decoupling Plan Order.*

[315] *See Decoupling For Electric & Gas Utilities: Frequently Asked Questions (FAQ),* National Association or Regulatory Utility Commissioners' Grants & Research Dept. (Sept. 2007); *see also Decoupling and Public Utility Regulation*, Graniere and Cooley, National Regulatory Research Institute No. 94-14 (August 1994).

the context of specific utility proposals included in general rate case filings rather than through a generic rulemaking."[316]

242 The following year, the Commission considered, and ultimately rejected as inadequate in scope and detail, a decoupling framework advocated by PacifiCorp.[317] Discussing the subject generally, the Commission stated:

> The central goal of conservation is to encourage customers to reduce energy use. As a result, a utility engaging in conservation will likely see its sales and revenues fall, exposing it to the risk of being unable to recover its fixed costs. Because shareholders bear the burden of any shortfall in revenues, they may be reluctant to aggressively pursue energy efficiency measures. Decoupling is a way to break the link between a utility's revenues and retail sales levels, and to reduce the utility's risk associated with recovering its fixed costs when retail sales decrease due to customer conservation.[318]

243 Later, the Commission undertook a more extensive discussion of decoupling in Docket UG-060267 where Puget Sound Energy (PSE) proposed decoupling for its natural gas utility.[319] There, after reiterating the purpose of decoupling, the Commission said:

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[316] Rulemaking to Review Natural Gas Decoupling, Docket UG-050369, Notice of Withdrawal of Rulemaking (October 17, 2005).

[317] *See UTC v. PacifiCorp*, Docket UE-050684, Order 04, ¶¶ 108-110 (April 17, 2006), setting out the Commission's basis for rejecting PacifiCorp's decoupling proposal.

[318] *Id.*, ¶ 102.

[319] *UTC v. Puget Sound Energy, Inc.*, Dockets UE-060266 & UG-060267, Order 08, ¶¶ 53-69 (January 5, 2007) [hereinafter *2007 PSE Decoupling Order*]. The Commission ultimately rejected PSE's natural gas decoupling proposal but did approve a three-year pilot electric energy efficiency incentive program for the Company (*see* ¶¶ 145- 158). The following week, however, the Commission conditionally approved a multi-party settlement in another company's rate case that included a three-year natural gas pilot decoupling project. *See UTC v. Cascade Natural Gas Corp.*, Docket UG-060256, Order 05, ¶¶ 67-85 (January 12, 2007) [hereinafter *2007 Cascade Decoupling Order*]; *see also* Order 06 in that same docket (August 16, 2007) which approved the Conservation Plan required in the conditional approval of the decoupling pilot and Order 07 (October 1, 2007) which accepted an addendum to the Conservation Plan.

> From a utility perspective, it is a means to ensure recovery of a significant part, or even all of its fixed costs regardless of reduced consumption. . . .
>
> Conservation advocates and others recognize decoupling as a potentially important tool to promote conservation. . . . We acknowledge that improved energy savings from cost-effective conservation, which we strongly support, is a highly appealing rationale for decoupling on its face. We emphasize, however, that decoupling is merely one regulatory tool in a larger toolbox of devices we might use to promote greater conservation.[320]

In that same order, we acknowledged the affect a decoupling mechanism may have upon a company's interest in pursuing conservation by noting:

> As the parties argue, decoupling is principally useful in circumstances where there is a need to promote a more positive company attitude toward conservation by removing what may be a disincentive, or barrier to aggressive pursuit of conservation . . . .[321]

244 Most recently, in the Commission's order approving the Avista decoupling pilot that is under direct review here, we reiterated the concerns that give rise to decoupling proposals:

> Under traditional ratemaking structures, utilities recover a large portion of their fixed costs through charges based on the volume of energy that consumers use. Consequently, a reduction in energy consumption may lower the probability that the utility can fully recover its fixed costs. Energy consumption may be lower for a variety of reasons. Consumers may lower their thermostats or take shorter showers. More energy efficient building codes and appliances, better and more efficient insulation, and warmer than normal weather can also reduce energy use. Conversely, an increase in energy consumption may lead to a utility over-recovering its fixed costs. The traditional financial incentives rewarding higher sales, some argue, create an environment

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[320] In that proceeding, the Commission mandated a direct incentive program for PSE's electric utility, wherein the company was rewarded or penalized for its conservation performance.

[321] *2007 PSE Decoupling Order*, ¶ 55.

> in which utilities do not support conservation because it is inconsistent with their economic interests.[322]

245 Our prior discussions of decoupling provide important context as we turn our attention specifically to Avista's proposal to retain its decoupling mechanism in this proceeding. We start with a discussion of the history and structural characteristics of the pilot mechanism. Following that, we describe the specific proposal pending here, discuss the parties' arguments for and against the program or various of its elements, and make our determinations concerning what will be authorized.

4. Avista's Pilot Decoupling Mechanism

246 In the context of a multi-party settlement, we approved Avista's Pilot Decoupling Mechanism on February 1, 2007.[323] The settling parties urged the Commission to adopt their settlement, contending that it would "provide for an increased focus on energy efficiency and conservation" within Avista Utilities, and "align the Company's interest with that of its customers with an increased focus on effective DSM [demand side management] programs."[324] In our order, we noted that the pilot program allowed us to "test the hypothetical benefits of decoupling generally" while providing sufficient "safeguards to protect [the customer]."[325] We also recognized the relationship between the Company's lost margin and the rate impacts of its decoupling mechanism. To this end, we stated:

> The proportion of margin lost to company sponsored DSM relative to the amount subject to recovery is of great interest to us, and we will closely scrutinize this factor in reviewing the results of this pilot decoupling program.[326]

[322] *2007 Avista Pilot Decoupling Plan Order*, ¶¶ 8-9.

[323] *Id.*, ¶ 7. Public Counsel and The Energy Project opposed the Settlement.

[324] *Id.*, ¶ 16.

[325] *Id.*, ¶ 31.

[326] *Id.*, ¶ 26.

247 We do not fully describe the decoupling program's details here, but instead point out that details as to its composition and operation are contained in the Commission's order approving the multiparty settlement and in the settlement document that is appended to that order.[327] We do however believe it necessary to refer to the basic construct of the program.

248 The pilot program allowed the Company to track therms sold to its Schedule 101 (residential and small business) customers.[328] Any deficiency in therms sold was recorded as "lost margin".[329] The pilot program's design went on to require that the Company's annual lost margin be adjusted by three important factors.

249 First, the effects of adding new customers are deducted from the Company's total or gross lost margin. This adjustment increased the lost margin available for recovery, which we will refer to here as the net lost margin. Second, the net lost margin was adjusted by factoring out the affects of weather through a process referred to as "weather normalizing." As weather has perhaps the greatest effect upon a gas utility's sales, this adjustment also significantly impacted the lost margin deferred. Finally, the utility was only allowed to recover 90 percent of the "weather normalized" lost margin. In other words, the adjusted net lost margin was reduced by an additional 10 percent. According to Staff, this 10 percent reduction was intended as an approximate substitute for discounting the utility's rate of return to reflect its reduced risk of revenue loss.[330]

250 In addition the Settlement imposed two other limitations on the Company. First, there was an earnings test, so that Avista could not earn more than its then-authorized 9.11

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[327] *Id.* The Settlement Agreement is found in Appendix A to Order 04.

[328] In order to "match" program results with customer sales over a given period, new customers' usage was not added to Schedule 101's total of therms sold.

[329] By program design, annual therm sales could exceed the annual sales attributed to this class for ratemaking purposes, which would result in rebates to customers. However, the program's short history indicated that after being weather-normalized, therm sales were invariably lower than the sales target.

[330] *See* Steward, Docket UG-060518, TR. 96:20 – 97:13 (Dec. 21, 2006) (testimony at settlement hearing regarding Staff's position on various constraints placed into decoupling mechanism).

percent rate of return. Second, there was a DSM (demand side management) test, which made recovery of Avista's "lost margin" subject to the Company achieving specific conservation targets.[331]

251 Thus, the program's design did not capture all lost margin, but was more refined, which allowed us to better understand the relationship between conservation and the Company's total therm sales and made an effort, albeit inexact, to account for the reduction in the Company's risk resulting from the pilot's implementation. We recognized then (and now) that the pilot program was (and should be) designed to best measure the Company's conservation efforts as a reflection of its "new" attitude toward conservation. In counterbalance, we also measure the program's impact on ratepayers to ensure that the program's costs are in reasonable balance with its benefits.

252 The approved settlement also called for a third-party evaluation of the pilot program. That evaluation, termed the "Titus Evaluation Report" (Titus Report) was filed with the Commission on March 31, 2009. To ensure a thorough review of the program and its impacts, the Commission determined that the pilot program must be evaluated in a general rate case, and that its permanent adoption must come only after "a convincing demonstration that the mechanism has enhanced Avista's conservation efforts in a cost-effective manner."[332] Consistent with our direction, Avista filed a petition to

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[331] According to the Settlement Agreement, the Company's rate of return (ROR) of 9.11 percent was approved by the Commission in its 2005 Avista Rate Case Order in Docket UG-050483. Further, the Settlement Agreement refers to the Company's 2006 IRP as establishing a natural gas target savings level of 1,062,000 therms (Washington & Idaho combined) for each of calendar years 2006 and 2007. Subsequent target savings levels were to be documented in a later IRP. *See 2007 Avista Pilot Decoupling Plan Order*, Appendix A at 5-6.

[332] *See 2007 Avista Pilot Decoupling Plan Order*, ¶ 33. *See also UTC v. Avista Corporation*, Dockets UE-090134, UG-090135 & UG-060518 (consolidated), Order 07, Supplemental Order Temporarily Extending Decoupling Mechanism, ¶ 15, n.15 (June 30, 2009), in which we state: "We have not undertaken a thorough review of the evaluation report submitted on March 31, 2009. However, it appears that, without further elaboration and analysis, it may not be sufficient to enable the Commission to evaluate the program pursuant to the standard we set for such review in Order 04. We look forward to a more robust and focused presentation as part of Avista's attempt to provide a 'convincing demonstration' that its decoupling mechanism is cost-effective and valuable not only for the Company, but also for its ratepayers."

make its pilot program permanent, and to consolidate its consideration with this general rate case.[333]

5. Issues Raised by the Parties

253 *Avista.* The Company requests continuation of its decoupling mechanism with some minor modifications. According to the Company, the pilot mechanism achieved its intended purpose: to substantially increase Avista's DSM efforts and results and allow the Company to recover a substantial portion of its fixed costs.[334] The Company points to a 61 percent increase in total therm savings across all Washington rate classes and a 205 percent increase in therm savings in Washington's Schedule 101 class over the period of the pilot.[335]

254 The Company states there is a need to improve measurement and verification of DSM savings, stating that it is in the process of developing a revised measurement and verification approach for review by Avista's External Energy Efficiency (Triple E) Board in September 2009 and for incorporation into the 2010 DSM Business Plan.[336]

255 Perhaps the most significant question raised in the proceeding was whether 90 percent represented the appropriate amount of lost margin to recover.[337] The Company states the decoupling mechanism is appropriately designed because it provides recovery of fixed costs related to the decline in customer usage, whether from programmatic DSM measures, education, price signals, or other factors.[338] The Company also stated

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[333] *See* Dockets UG-090135 & UG-060518, Petition of Avista Corporation *and* Avista Corporation's Motion to Consolidate (April 30, 2009).

[334] Hirschkorn, Exh. BJH-1T-A at 4:7-12.

[335] *Id.* at 10:3-9.

[336] Powell, Exh. JP-3T at 1:15-16 and 8:1-2.

[337] In other words, whether the deferred "lost margin" in balance with the amount of actual lost margin related to Company-sponsored conservation efforts. At hearing, this was referred to as the "proportionality" issue.

[338] Hirschkorn, Exh. BJH-1T-A at 11:11-18. According to the Company, "programmatic measures" consist of a series of prescriptive rebates for residential measures, an enhanced incentive program for limited income customers, and a non-residential program applicable to any

that DSM expenditures for limited-income customers increased by 43 percent during the decoupling period.[339]

256 However, in its rebuttal case, the Company recommends reducing the recovery level to 70 percent due to "the variables outside the normal ebb and flow of customer usage over time." At hearing, Avista acknowledged that the decoupling mechanism allows for recovery of lost margin due to all factors but weather, and agreed that the reduction in the percentage of recovery it proposed was a "rough approximation" aimed at taking into account lost margin from causes other than Company DSM efforts.[340]

257 The Company also proposes to modify the mechanism in a minor way. According to the Company, some customers left Schedule 101 for Schedule 111 causing phantom margin losses of about five percent of the total lost margin deferred under the pilot.[341] The Company suggests that the permanent program remove the effect of those customers from the deferral amount.[342]

258 *Commission Staff.* In responsive testimony, Staff opposes the continuation of Avista's decoupling program for three primary reasons: administrative burden, complexity, and the proportion of DSM lost margin to the deferral amount.[343] As an alternative, Staff proposes phasing out the decoupling mechanism beginning January 1, 2010, and terminating it on January 1, 2011. At that time, Staff recommends

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measure that saves electric or natural gas energy. "Non-programmatic" activities are educational and outreach campaigns focused upon efficiency measures that are not included in Avista's programmatic measures, such as "Every Little Bit". *See* Powell, Exh. JP-1T at 4:2-9.

[339] *Id.* at 22:2-4.

[340] Norwood, TR. 1029:8-25 and 1030:1-9.

[341] *Id.* at 12:19-13:1. According to the Titus Report, "Schedule 101 (General Service – Firm – Washington) is available for residential and low usage commercial customers that use less than 200 therms per month. Schedule 111 (Large General Service – Firm – Washington) is generally a commercial rate schedule that consists of a higher minimum charge and is based on usage greater than 200 therms per month. *See* Exh. BJH-2-A (revised Aug. 10, 2009), at 65.

[342] Hirschkorn, Exh. BJH-1T-A at 12:5-12.

[343] Reynolds, Exh. DJR-1T at 19:5 and 25:22 – 26:2.

increasing the Schedule 101 basic charge to $10 per month,[344] and asserts this would stabilize Company revenue expectations without creating complicated accounting requirements and rates for Schedule 101 customers.[345]

259 As an alternative, should the Commission continue the decoupling mechanism, Staff recommends two modifications: the removal of the new customer adjustment and the addition of the Schedule 111 migration adjustments as described by the Company.[346]

260 Regardless of the Commission's decision on the continuation of decoupling mechanism, Staff recommends the Commission direct the Company to convene meetings with Staff and interested parties to design conservation reporting and stakeholder involvement protocols, including expansion of the Company's evaluation standards.[347] Staff suggests the results of these meetings be filed with the Commission within 12 months of the final order.[348]

261 Staff concludes that the decoupling evaluation was partially incomplete because the Company's third-party evaluator (Titus) was not allowed to draw conclusions, make recommendations, or otherwise determine whether conservation increased as a result of implementing decoupling.[349] Staff conditionally concludes that spending on conservation and therm savings increased during the term of the mechanism, but notes that during the last four years therm savings fluctuated wildly, decreasing at times almost as much as they increased. Staff indicates this is a concern because it is unclear how much, if at all, the mechanism contributed to the therm savings.[350]

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[344] *Id.* at 2:10-16.

[345] *Id.* at 26:15-17.

[346] *Id.* at 2:17-21.

[347] *Id.* at 3:3-7 and 8:10-14.

[348] *Id.* at 2:5-7.

[349] *Id.* at 7:1-13 (according to Staff, "other parties on the Stakeholder Advisory Group resisted" Staff's urging of the Company that Titus be allowed "to draw conclusions and make recommendations about the design of the mechanism").

[350] *Id.* at 8:1-5 and 9:21.

According to Staff, this reflects a problem with the Company's evaluation program. In the end, Staff still concludes that Avista's conservation efforts have been enhanced.[351]

262 In considering the proportionality of deferrals to DSM lost margin, Staff notes that, even accounting for multi-year losses, the deferral was three times the lost margin attributable to the Company's programmatic conservation efforts.[352] It concludes however, that the purpose of the decoupling mechanism is to remove the Company's disincentive to invest in conservation by stabilizing the amount of revenue the Company could count on collecting.[353] Therefore, the deferral under the decoupling mechanism should not be tied to programmatic DSM lost margins only.

263 *Public Counsel.* Public Counsel testified in opposition to Avista's decoupling mechanism and recommends that it be discontinued. In support, it asserts multiple areas of concern: the DSM savings trend does not correspond to adoption of decoupling; the deferrals are not proportional to the lost margin; the customer outreach programs are not as effective as claimed; the new customer adjustment is unreasonable and violates the matching principle; the mechanism is complex and presents administrative burden; the risk of loss is shifted to the ratepayers; and Avista's calculation of DSM' savings is flawed.[354] We turn now to the details of Public Counsel's arguments.

264 Public Counsel argues that Avista's DSM savings did not correspond to the adoption of decoupling in Washington, noting that the greatest increase in therm savings occurred in Idaho where there is no decoupling mechanism.[355]

265 Public Counsel characterizes the decoupling mechanism as overly broad in scope; it collects lost margins from a number of causes unrelated to Avista's conservation

[351] *Id.* at 9:21-22.

[352] *Id.* at 19:8-9; *see also* Staff Brief, ¶ 83 (on brief, however, Staff asserts the deferral was *four* times the lost margin attributable to the Company's programmatic conservation efforts).

[353] *Id.* at 19:18-20.

[354] Brosch, Exh. MLB-1T at 6:6-7:3.

[355] *Id.* at 12:4-9.

efforts.[356] Citing the Titus Report, Public Counsel states that the ratio of deferred lost margin to the lost margin due to Company-sponsored conservation is 10:1 in 2007 and 8:1 in 2008.[357] Public Counsel dismisses the Company's claim that non-programmatic DSM from Company educational programs such as "Every Little Bit" is a significant part of the deferral, although it fails to quantify a precise number.[358]

266 As to the mechanism's new customer adjustment, Public Counsel argues that it violates the matching principle by excluding new loads when calculating the deferral. It notes that if the adjustment were eliminated, the deferral would actually be negative, resulting in a refund to customers.[359] If the Commission chooses to continue the decoupling mechanism, Public Counsel recommends removing the new customer adjustment.[360]

267 In its brief, and at the hearing, Public Counsel spent considerable effort discussing the administrative complexity of the program. Public Counsel argues that the mechanism can lead to formal reviews under compressed schedules. It also claims that other elements of the mechanism add complexity, such as the weather adjustment, DSM test, the customer migration adjustment, and the earnings test; nevertheless, Public Counsel does not suggest eliminating any of these elements if the Commission approves continuation of the mechanism.

268 Finally, Public Counsel attacks Avista's calculation of DSM savings. It argues that the Company relies only on "engineering estimates" of DSM savings and does not measure and verify such savings on a facilities basis.[361] The result, Public Counsel

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[356] *Id.* at 13:6-10.

[357] *Id.* at 16:8-10.

[358] *Id.* at 19:7 – 20:5. Staff points out that "Every Little Bit" has a very small budget, only raises customer consciousness on conservation and directs customers to programmatic measures that are counted in the therm savings.

[359] *Id.* at 15:18-26.

[360] *Id.* at 25:15-19.

[361] Kimball, Exh. MMK-1T at 2:10-18.

argues, is that the Commission and stakeholders are left with insufficient evidence or information to accurately evaluate Avista's stated DSM savings.[362]

269 If the Commission should conclude that there is a need for financial incentives to encourage Avista's investment in energy efficiency, Public Counsel recommends an incentive mechanism with payments that are proportional to the margins lost due to Company sponsored DSM performance.[363] As part of an incentive mechanism, Public Counsel recommends clearly defined DSM performance targets, with meaningful measurement, verification and reporting of results achieved by the utility relative to such targets.[364]

270 Finally, Public Counsel argues that if the Commission approves a decoupling program, it should reduce the return on equity figure agreed to in the Settlement by 25 basis points to account for reduced investor risk. Public Counsel compares the Company's return on equity to a return that reflects the greater probability of cost recovery provided by the Decoupling Mechanism.[365]

271 *The Energy Project.* The Energy Project recommends that the Commission terminate the mechanism. It contends that limited income customers and many more payment-troubled customers pay higher prices for essential natural gas service but do not receive any of the potential direct benefits from the more expensive DSM programs that Avista has implemented.[366]

272 Citing the Titus Report, the Energy Project testifies that Avista's DSM expenditures on Washington residential customers increased 25 percent in 2007 and another 50 percent in 2008. On the other hand, such expenditures for limited income customers increased 17 percent in 2007 and only 12 percent in 2008.[367] The ratio of DSM

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[362] *Id.*

[363] Brosch, Exh. MLB, at 41:21-22.

[364] *Id.* at 41:1-18.

[365] Gorman, Exh. MPG-1T at 5:15-17 and 7:20-22.

[366] Anderson, Exh. BRA-1T at 4:6-10.

[367] *Id.* at 12:8-11.

dollars spent on limited income customers dropped from 1-in-6 in 2007 and 1-in-8 in 2008.[368]

273 *The NW Energy Coalition.* In responsive testimony, the NW Energy Coalition (Coalition) recommends the Commission continue Avista's decoupling mechanism. It argues that the program is necessary because there is a well established asymmetrical trend of declining use per customer and that breaking the link between sales and revenue is the best way to focus the utility on making the lowest reasonable cost investments to deliver reliable energy services to customers.[369] However, the Coalition suggests three modifications.

274 First, the Coalition suggests that Avista's maximum deferral should be reduced from 90 percent to a maximum of 70 percent of the "fixed cost margin difference" for both refunds and collections.[370] The Coalition supports lowering the percentage maximum deferral to 70 percent, stating that it is important in the current economic climate for a more equitable sharing of financial risk between Avista and its customers.[371]

275 Second, the Coalition proposes an incentive within the decoupling mechanism to encourage and reward performance in excess of Commission-approved targets.[372] Under its incentive feature, the Company would have to achieve savings greater than 120 percent of its DSM target to earn the 70 percent deferral. If the Company met its DSM target, then it would only recover 50 percent of its deferral.[373]

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[368] Titus Report at 29.

[369] Glaser, Exh. NLG-1T at 12:20-31and 8:10-26.

[370] *Id.* at 5:7-8.

[371] *Id.* at 10:20-21.

[372] *Id.* at 6:19-31.

[373] *Id.* at 12:13-18.

276 Third, the Coalition recommends that the Company be required to meet two DSM targets: an overall DSM target, as is currently the case, and a specific DSM sub-target for Washington limited income customers.[374]

277 *Responses of Staff, The Energy Project, Public Counsel, and Coalition.* Staff's cross-answering testimony opposes The Energy Project's characterization of the decoupling mechanism's purpose as recovering lost revenues due to the implementation of efficiency programs.[375] Staff stresses that the design of the mechanism was to recover all lost margins associated with reductions in usage other than weather.[376]

278 Staff generally supports the Coalition's incentive proposal but argues it will encourage the Company to establish low DSM targets.[377] Staff agrees with The Energy Project that the Titus Report was "unable to actually confirm that the claimed energy savings have occurred."[378] However, Staff disagrees with Public Counsel's claim that the DSM verification adjustments are insufficient to allow for proper adjustment of the Company's total savings claims.[379]

279 In its cross-answering testimony, The Energy Project does not agree that the modifications to the decoupling mechanism and the limited income DSM spending target suggested by the Coalition can be relied on to support the program's continuation.[380]

280 The Energy Project criticizes Staff's rate design proposal because it does not address the Company's disincentive to promote conservation. Furthermore, the feature to

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[374] *Id.* at 12:5-21.

[375] Reynolds, Exh. DJR-3T at 2:21 – 3:2.

[376] *Id.*

[377] *Id.* at 4:1-23.

[378] *Id.* at 5:9-10 (quoting Alexander, Exh. BRA-1T at 5:1-2).

[379] *Id.* at 5:18-23.

[380] Alexander, Exh. BRA-2T at 4:9-11.

reduce low-income customers' basic charge is not well developed.[381] It provides its own Bill Analysis Model results and claims Staff's rate design proposal would have a discriminatory impact on limited income customers.[382]

281 Public Counsel and The Energy Project object to Staff's proposed increase in the customer fixed charge, which would be a step toward what is termed "straight-fixed variable" (SFV) rate design.[383] They cite data that show local distribution companies with volumetric charges are able to achieve reasonable rates of return.[384] These parties jointly disagree with Staff's characterization of the effect of price elasticity, asserting that it may be hard to measure but, as several studies show, it does have a real effect on consumption.[385] The joint rebuttal parties conclude by reiterating their support of a $6.00 customer basic charge (twenty-five cent increase over the existing customer charge) whether decoupling is continued or not.[386]

282 In cross-answering, the Coalition reasserts its support for the decoupling mechanism, arguing its recommended modifications and other recommendations address concerns raised about the mechanism. The Coalition asserts that its modification to reduce the maximum recovery amount to 70 percent addresses the concerns raised by Public Counsel about the proportionality of the mechanism.[387] The Coalition disagrees with Public Counsel that the mechanism should be limited just to cost recovery for programmatic DSM savings.[388] The Coalition asserts that such a limitation will discourage the Company's efforts to promote non-programmatic DSM and discourage

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[381] *Id.* at 6:5-8.

[382] *Id.* at 9:9-17.

[383] Straight-fixed variable (SFV) refers to a rate design that collects all or a substantial portion of fixed costs through a fixed monthly charge on each customer, rather than through a volumetric rate.

[384] Watkins, Exh. GAW-3T at 3:8-10.

[385] *Id.* at 11:21-12:9.

[386] *Id.* at 12:12-18.

[387] Glaser, Exh. NLG-3T at 5:18-22.

[388] *Id.* at 6:4-5.

support for public policies such as building codes and efficiency standards that cause a decline in therm use.[389]

283 The Coalition also disagrees with Staff's recommendation to replace the decoupling mechanism with higher fixed charges and asserts that higher fixed charges discourage customer investment in conservation. It also contends that Staff did not establish a relationship between its proposed $10 customer charge and Avista's cost to serve a customer.[390]

284 The Coalition agrees with Public Counsel and Staff that Avista's future DSM performance should be more effectively evaluated.[391] Persuaded by Public Counsel and The Energy Project's evidence provided in responsive testimony, the Coalition specifically supports the recommendation to require independent bill verification analysis that examines changes in customer usage as a result of DSM programs.[392] The Coalition considers this particularly important as energy conservation becomes a larger resource within the utility's resource portfolio.

285 *The Company's Revised Proposal.* On rebuttal and at the hearing, the Company offers three modifications to its initial proposal, assuming that the new customer adjustment is retained.[393] First, the Company supports lowering the deferral recovery from 90 to 70 percent of its lost margin, so long as 100 percent of its projected DSM savings are achieved. However, the Company offered a different rationale for the 70 percent figure than the Coalition.[394] Avista's witness, Mr. Norwood agreed that

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[389] *Id.* at 6:5-8.

[390] *Id.* at 7:6-8.

[391] *Id.* at 1:10-15.

[392] *Id.* at 1:13-15.

[393] Norwood, Exh. KON-1T at 31:19-32:3 and 50:10-21.

[394] The allowed recovery would not be the lower of the two DSM tests (the IRP DSM savings targets and the DSM savings of limited income customers), but a product of the percentage allowed by each test. For example, if one test allowed 70 percent and the other 90 percent then the allowed percentage would be 0.7 times 0.9, or 63 percent. *See* Norwood, Exh. KON-1T at 49:10-19.

the 70 percent figure was intended as a "rough approximation" of lost margin attributable to Avista's programmatic and non-programmatic conservation efforts.[395] Second, it suggested a limited income test, whereby five percent of programmatic DSM savings must come from the limited income sector.[396] Third, the Company would work with the parties to address the Company's measurement and verification of DSM savings, with the results filed with the Commission by September 30, 2010.[397]

286 The Company recommends rejecting Staff's and Public Counsel's proposals to eliminate the new customer adjustment (if the decoupling mechanism is continued) and states that it would not even consider continuation of the mechanism if the new customer adjustment were to be removed.[398]

287 The Company also recommends rejection of Staff's rate design alternative, stating it would prefer to collect all fixed charges through a fixed charge but claims the basic charge would need to be $22.45 per month.[399] It testifies that Staff's proposal to subsidize the fixed charge for LIHEAP and LIRAP customers is administratively burdensome.[400]

288 In response to the Energy Project, Avista asserts that limited income customers do obtain a proportionate benefit from its low-cost and no-cost energy education

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[395] Norwood, TR. 1030:4-9.

[396] Norwood, Exh. KON-1T at 49:12-19.

[397] Norwood, Exh. KON-1T at 32:1-3.

[398] Hirschkorn, Exh. BJH-8T at 5:21-23; *see also* Hirschkorn, TR. 1130:15-19.

[399] Norwood, Exh. KON-1T at 45:13-17. However, in response to questions from the bench, Mr. Norwood recognized that such a rate structure could provide less of an incentive to customers to conserve. TR. 1032:20 – 1033:7.

[400] *Id.* at 46:12-21.

messages delivered through Avista's outreach programs.[401] Avista admits, however, that it does not collect income information from its customers.[402]

6. Commission Decision

289 Conservation is one of our cornerstone missions. Consequently, we encourage and support efficiency programs as one of the key objectives in our ratemaking. We have long recognized that conservation is, under almost all circumstances, the least cost energy resource available to a utility and its ratepayers.[403] To further its development, we enable company spending on conservation resources by allowing our utilities to collect all costs associated with their respective conservation programs from ratepayers, subject to an annual reconciliation or "true-up." In addition, we have provided financial incentives for meeting and exceeding conservation targets[404] and have approved pilot programs for the purpose of determining whether mechanisms, such as the one we have before us, would support a "conservation" culture within our regulated utilities.[405] With this in mind, we judge Avista's decoupling mechanism and whether it has effectively increased the utility's efforts to support cost-effective conservation programs for its customers.

290 After careful evaluation, we conclude that Avista's decoupling mechanism has enhanced the Company's conservation efforts and that, with some further modifications, it can continue to do so in a manner that balances the interests of ratepayers and the Company. As further explained below, we grant Avista's petition to continue the decoupling mechanism with several modifications and require the parties to study certain elements of the mechanism for future review. We believe that the modifications we require refine the mechanism to better align the Company's

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[401] Powell, Exh. JP-3T at 10:16 – 11:7.

[402] *Id.* at 10:4-5 and 11:1-2.

[403] Cost-effective conservation potentials have been clearly identified for decades. The difficulty is achieving them. Hence, the Commission's consideration of decoupling in this docket.

[404] *2007 PSE Decoupling Order*, ¶¶ 145-158.

[405] *2007 Cascade Rate Case Order*, ¶¶ 67-85; *2007 Avista Pilot Decoupling Plan Order*.

recovery of its lost margins with the impacts of its own programmatic and non-programmatic conservation efforts.

a. Recovery of Lost Margin

291 *The "Lost Margin" Issue.* The Company argues that its decoupling mechanism is necessary to allow the recovery of fixed costs approved in the most recent general rate case.[406] We disagree that decoupling's purpose is so broad. The regulatory construct for decoupling in Washington has centered on the utility's performance relative to conservation. Our approval of decoupling in our two pilot programs[407] was founded on the premise that lost margins affected the utility's appetite for offering additional conservation programs. Thus, both pilots required the companies to account for lost margin due to conservation, and to discriminate between the various causes of lost margin. In that more limited context, we conclude that the recovery of lost margin attributable to Avista's programmatic and non-programmatic conservation endeavors is sufficient to encourage Avista's DSM efforts.[408] We seek to avoid guaranteed recovery of lost margin that would occur should lost margin from other causes be included in the mechanism.

292 For this same reason, as well as for other reasons, we decline to adopt staff's proposed alternative of a higher fixed charge that is designed to provide for similar recovery as would have occurred under the decoupling pilot's design.[409] We also note that with such rate designs, the variable charge for gas purchased would be smaller, thereby decreasing the incentive for each customer to conserve on his or her usage. However, we do approve increasing the customer charge slightly by twenty-five cents per month to $6.00 per month. This was proposed by the Company and supported by Public Counsel and the Energy Project.

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[406] Norwood, Exh. KON-1T at 44:14-15 and 45:3-4. The Company states that the purpose of the mechanism is, "to provide recovery of fixed costs previously approved by this Commission,…" [emphasis in original].

[407] *2007 Cascade Rate Case Order*, ¶¶ 67-85; *2007 Avista Pilot Decoupling Plan Order*.

[408] Norwood, Exh. KON-1T at 36:18-21.

[409] Reynolds, Exh. DJR-1T at 26:15-17.

293 *Amount of Deferral Allowed for Later Recovery.* In its initial filing, Avista requested that the pilot program's 90 percent deferral feature be extended on a permanent basis.[410] However, in its rebuttal case, the Company recommends reducing the recovery level to 70 percent due to "the variables outside the normal ebb and flow of customer usage over time." At hearing, Avista acknowledged that the decoupling mechanism allows for recovery of lost margin due to all factors but weather, and agreed that the reduction in the percentage of recovery it proposed was a "rough approximation" aimed at taking into account lost margin from causes other than Company DSM efforts.[411]

294 We do not agree with what appears to be the Company's arbitrary 70 percent figure for recoverable lost margin.[412] We find no real record support for the Company's linking that percentage to the lost margin attributable to its programmatic and non-programmatic conservation programs. In our approval of the pilot program, we assigned to Avista the burden of justifying the continuation of the program. In our view, basing a 70 percent deferral on a "rough approximation" is not adequate to meet that burden. In effect, that is a "top-down" approach: determine the total lost margin and then subtract some estimated percentage that may be attributable to other causes of lost margin.

295 We recognize that determining how much of the Company's lost margins are attributable to its conservation efforts is a difficult task. However, it is not impossible. We have a record before us that shows the parties' estimates of recoverable lost margin to range from 10 percent to the Company's 70 percent.[413] It appears that Staff and Public Counsel have determined their estimates of the

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[410] Staff, asserts that the programs purpose was to include lost margin due to all reasons, not just conservation programs. Reynolds, Exh. DJR-3T at 2:19 – 3:3. The pilot decoupling program approved was a *partial* decoupling mechanism that excluded weather before it calculated all other effects.

[411] *Id.*

[412] Reynolds, Exh. DJR-1T at 19:11-13.

[413] In the future, we expect the Company (and indeed the parties, too) to do better at making such an empirical assessment.

Company's percentage of lost margin by using a "bottom up" approach, which we believe best to arrive at a fair and equitable result. Using this approach, we start with evidence as to Avista's programmatic conservation efforts, add the ascertainable impacts of its non-programmatic (including educational) efforts, and fix this amount for deferral and later recovery. We turn now to the record before us.

296 As noted above, nearly every party submitted evidence from which we can gauge the lost margin attributable to the Company' programmatic conservation efforts:

- *Avista.* Avista concludes that the *total* deferral and recovery should be 70 percent. It does not effectively distinguish between its programmatic and non-programmatic efforts and all other causes.[414]

- *Public Counsel.* Citing the Titus Report to support its conclusion, Public Counsel states that the ratio of the lost margin due to Company's programmatic conservation to the deferred lost margin was 10 percent in 2007 and 12.5 percent in 2008.[415] It notes, however, that these ratios do not take into account the effect of interceding rate cases.[416]

- *Staff.* Commission Staff portrays a more favorable view of the proportionality of the Company's deferrals to its programmatic lost margin and concludes that, even accounting for multi-year losses, Avista's deferred lost margin was three times the lost margin caused by its DSM program, or 33 percent of the total deferral.[417] We note that Staff's ratio includes the effect of the interceding rate case. (However, in its brief, Staff estimates the percentage as 25 percent.)[418]

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[414] In fact, Avista's own third-party evaluator did not attribute 70 percent of the Company's lost margin to its conservation program. *See* Exh. BJH-2-A (Titus Report) at 9.

[415] Brosch, Exh. MLB-1T at 16:8-10.

[416] We recognize that the amount of money deferred over a twelve month period grows with the amount of time between rate cases, resulting in different percentages depending on how long the gap between rate cases. We expect an increase in the incremental DSM achieved over time and, therefore, incremental increases in the lost margin from Company sponsored programmatic and non-programmatic efforts. Though the Company, in recent years, has filed rate cases annually, this fact should encourage, at least somewhat, the Company to refrain from filing general rates so frequently.

[417] Reynolds, Exh. DJR-1T at 19:8-9.

[418] Staff Brief, ¶ 83.

- *Coalition.* The NW Energy Coalition proposes that if the Company should meet its DSM target, then it should be allowed to recover 50 percent of its deferral.[419] However, the Coalition also recommends the Company be provided an incentive for achieving DSM levels above its current target. It also supports allowing the Company to recover lost margins due to other causes in addition to those related to programmatic and non-programmatic conservation.

297 We now turn to the impacts of the Company's non-programmatic DSM efforts which are even more difficult to determine. The Company asserts its educational DSM efforts, such as its "Every Little Bit" program, produce DSM savings that contribute to lost margins.[420] These claims rest on descriptions of the Company's various non-programmatic efforts[421] and the testimony of Mr. Kelly Norwood, who opined that the Every Little Bit program works as intended. However, the Company does not make an effort to quantify the *actual* impact of its efforts.[422] In rebuttal, Public Counsel offers its own assessment and in brief argues the Company presented no *quantifiable* evidence of DSM savings from its non-programmatic efforts.[423] Basing its conclusions on the education program's budget, Public Counsel states that the non-programmatic savings are not significant.[424] Commission Staff testifies that the non-programmatic efforts have made a significant contribution to conservation, but does not quantify the effect.[425] The Coalition states it believes that conservation from the non-programmatic efforts are significant, but also does not quantify it.[426]

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[419] Glaser, Exh. NLG-1T at 12:13-18.

[420] Powell, Exh. JP-1T at 4:1-17.

[421] *Id.* The "Every Little Bit" education and outreach program is part of the Company's non-programmatic DSM efforts. *See* Exh. JP-2.

[422] Exh. KON-2-X.

[423] Brosch, MLB-1T at 19:19 – 20:5; Public Counsel Brief, ¶46.

[424] Brosch, MLB-1T at 19:19 – 20:5.

[425] Reynolds, DJR-1T at 9:21 – 10:3.

[426] Glaser, NLG-1T at 12:27-29.

298 We recognize that the Company's non-programmatic efforts are an important part of its overall conservation efforts and encourage the Company to continue to educate its ratepayers as to the benefits of energy efficiency. Unlike the testimony offered in response to the Company's programmatic efforts, the record here presents only opinions of the amount of savings attributable to the Company's non-programmatic efforts or, in the case of Public Counsel, an indirect method of assessing the program's effect. Given this record, we conclude that the Company's non-programmatic efforts produce real savings. However, it appears that such savings do not compare with savings due to the Company's programmatic expenditures.

299 Combining our judgment on the level of the Company's non-programmatic and programmatic efforts, and based on the record before us, we conclude that 45 percent of Schedule 101's lost margins are attributable to these efforts and set the maximum recovery at that amount. This level provides for the recovery of all lost margins from Company sponsored conservation, allocates a generous percentage to its non-programmatic efforts, and balances the Company's recovery under the program with ratepayers' interests. In choosing a percentage level for the target to achieve this goal we recognize the complexity and uncertainty of the task revealed in the record and that this maximum deferral percentage may change in future cases as the parties develop further evidence. We leave the percentage point reductions in the percentages of lost margin recoverable for falling below the DSM target unchanged.

Current Mechanism

Actual vs. Target DSM Savings	Amount Deferred
<70%	60%
>80% and <90%	70%
>90% and <100%	80%
100%	90%

Commission Decision

Actual vs. Target DSM Savings	Amount Deferred
<70%	15%
>80% and <90%	25%
>90% and <100%	35%
100%	45%

300 *Other Modifications.* There are two other modifications to the program that we find necessary and appropriate. First, we agree that DSM savings attributable to Idaho should be excluded from the target. At its initiation, the pilot program's target included DSM savings for Idaho. Since that time, the Company has been able to allocate program impacts between the jurisdictions. Consequently, both the Titus Report and Company testimony present DSM savings on a Washington jurisdictional basis. Therefore, to better match benefits to those paying the cost, we modify the decoupling mechanism to set the program's targets and measure its achievement using only Washington DSM savings. This new requirement will be effective with the target set as a result of the Company's 2009 natural gas Integrated Resource Plan.

301 Second, we require that the lost margin calculation be adjusted to remove the effect of customer migration between Schedule 101 and Schedule 111. The Company has testified that customer migration may account for five percent of the total lost margin deferred.[427] We accept the method the Company proposes for removing the effect of customer migration.

302 *New Customer Adjustment.* We reject Staff and Public Counsel's proposal to eliminate the new customer adjustment. In approving the pilot mechanism, we agreed to include this adjustment in order to better understand the actual impacts of Avista's conservation program. In this order, we reiterate our support for basing recovery under the program upon the conservation efforts of the Company. Were we to remove this adjustment, recovery of lost margins due to conservation would decrease due to the addition of therms sold to new customers, undercutting the central reason we allow this program to go forward.

303 *Future Inclusion of All Customer Classes.* By reducing the Company's natural gas load, including its peak requirements, Avista's conservation program benefits all customers. In fact, the decoupling program includes conservation from all rate schedules in setting its targets and determining its success. Even so, as now put in place, the program's lost margin is only collected from Schedule 101 customers. Following the principle of costs following benefits discussed above, we expect the

[427] Hirschkorn, Exh. BJH-1T-A at 12:7 – 13:12.

parties to address whether the program should recover DSM-related lost margin from all rate schedules in Avista's next general rate case.

b. Measurement of DSM Achievement

304 It is obvious from the record that the parties have struggled to determine the actual impact of the Company's conservation program.[428] Testimony relates this problem in part to the lack of evaluation, measurement and verification (EM&V) techniques for conservation programs. Public Counsel's analysis, while a sampling, indicates significant shortcomings in the Company's EM&V methods.[429] Staff recommends the Company work with interested parties in a collaborative process to design a consistent and accurate measurement method. The Coalition supports this idea.[430] On rebuttal, the Company agrees there is a need to improve measurement and verification of DSM savings, stating that it is in the process of developing a revised measurement and verification approach for review by its Triple-E board. After review the Company will incorporate the revised approach into its 2010 DSM Business Plan.[431]

305 We recognize that the cost-effectiveness and therefore prudence of programmatic DSM expenses and lost margin recovery under any decoupling or incentive mechanism rests on the evaluation, measurement and verification of energy savings achieved. Furthermore, we agree with the parties that Company's EM&V efforts need to be improved. We require the parties to join in the collaborative planned for this subject, and expect them to participate in the development of consistent and accurate methods to judge the effectiveness of all energy efficiency programs and measures. We also require the Company to file an EM&V plan for its DSM programs

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[428] Various intervenors question the accuracy of the therm savings claimed by the Company during the decoupling pilot program. *See* Reynolds, Exh. DJR-1T at 8:7-14; Kimball, Exh. MMK-1T at 2:9 – 3:11; Glaser, Exh. NLG-5T at 1:9-15.

[429] Kimball, Exh. MMK-1T at 2:9-3:11.

[430] Glaser, Exh. NLG-5T at 1:9-13.

[431] Powell, Exh. JP-1T at 8:1-2.

by September 1, 2010. The plan should include a bill verification analysis that examines changes in customer usage as a result of DSM programs.

c. Low-Income Conservation Achievement

306 The Company's low-income conservation achievement during the decoupling pilot is particularly disappointing. As the program's impact on low-income customers remains a key issue, we direct the Company, working in collaboration with the parties, to explore new approaches to promote low-income conservation, to identify barriers to its development, and to address the issues raised by The Energy Project. The Company shall report its conclusions to the Commission at the same time it submits the EM&V report.

d. Deferrals Made from July 1, 2009, to the Effective Date of This Order

307 In our order granting the Company an interim extension of its pilot program, we deferred consideration of the issue of how the decoupling program would operate from the end of the pilot until the effective date of this Order.[432] The Company agreed in its extension request to adjust deferral accounts to reflect modifications to the mechanism that the Commission required. Therefore, we now order the application of the conditions of this order to deferrals calculated on or after July 1, 2009.

e. Risk Reduction and Modified Return on Equity (ROE)

308 We decline here to adopt a modification to the Company's return on equity. We acknowledge that reducing a Company's risk can result in a reduction of its return on equity. However, the testimony supporting such a reduction does not address the modifications we have made to the mechanism. The only evidence presented was an adjustment sponsored by Public Counsel and ICNU based on the Company's recovery of 90 percent of the deferred margin.[433] As reflected herein, we have reduced the recovery amount to 45 percent. We believe this reduction to be a substantive change

[432] Dockets UE-090134, UG-090135 & UG-060518, Order 07, ¶¶ 13, 16, 17.

[433] Gorman, MPG-1T at 5:15-17 and 7:20-22.

not addressed by the Public Counsel and ICNU joint testimony. For this reason, we withhold judgment on this issue, but remain open to the parties developing this concept further in future proceedings.

f. Summary

309 Despite some shortcomings, the Company's pilot decoupling mechanism achieved the goal of incrementally increasing Avista's company-sponsored conservation efforts. However, its initial design should be modified to better align the Company's interests with that of its customers. We believe this is accomplished by allowing the Company the opportunity to recover lost margins related to its programmatic and non-programmatic conservation efforts. While lower than the amount requested by Avista, we believe this amount is sufficient to encourage and support its ongoing and developing conservation program. We note that decoupling is but one method of supporting conservation, and we encourage the Company and parties to consider alternatives that avoid the mechanism's inherent complications, while accomplishing the objectives we set forth herein.[434]

FINDINGS OF FACT

310 Having discussed above in detail the evidence received in this proceeding concerning all material matters, and having stated findings and conclusions upon issues in dispute among the parties and the reasons therefore, the Commission now makes and enters the following summary of those facts, incorporating by reference pertinent portions of the preceding detailed findings:

311 (1) The Washington Utilities and Transportation Commission is an agency of the State of Washington, vested by statute with authority to regulate the rates, rules, regulations, practices, and accounts of public service companies, including electrical and gas companies.

312 (2) Avista is a "public service company," an "electrical company," and a "gas company" as those terms are defined in RCW 80.04.010 and used in Title 80

[434] *See, e.g., 2007 PSE Decoupling Order.*

RCW. Avista is engaged in Washington in the business of supplying utility services and commodities to the public for compensation.

313 (3) Avista filed on January 23, 2009, certain revisions to its currently effective tariffs, including rate increases for customers of its electric service and gas services in Washington. The revised tariff sheets bore an effective date of February 23, 2009.

314 (4) The Commission suspended the operation of the proposed tariff revisions on February 3, 2009, pending an investigation and hearing in Docket UE-090134 and UG-090135.

315 (5) On September 4, 2009, the parties filed a Settlement Stipulation that, if approved, would resolve some, but not all, issues concerning cost of capital, power costs, rate spread and rate design, and other matters.

316 (6) Considering the proposed Settlement Stipulation and the full evidentiary record following hearing, the Commission determined that Avista's existing rates for electric service and natural gas service provided in Washington are insufficient to yield reasonable compensation for the services rendered. Avista accordingly requires prospective relief with respect to the rates it charges for electric and natural gas services provided in Washington.

317 (7) Avista requires additional revenue as reflected in the Settlement Stipulation as conditioned by this Order, the uncontested adjustments summarized in Table 2A for electric service and Table 2B for natural gas service, and the Commission's resolution of contested adjustments as detailed in the body of this Order and summarized in Table 4 for electric service and Table 5 for natural gas service.

318 (8) It is in the public interest to increase the Low Income Rate Assistance Program portion of Schedules 91 and 191 as specified in the Settlement Stipulation.

319 (9) Avista failed to file the necessary documentation in this proceeding to allow the Commission to adequately review the Lancaster contracts as an affiliated transaction or for compliance with greenhouse gas emissions standards.

320 (10) On April 30, 2009, Avista filed a petition to consolidate Docket UG-060518, concerning its pilot natural gas decoupling mechanism, with the rate case proceedings in Dockets UE-090134 and UG-090135. The Company asked the Commission, among other things, to extend the pilot program beyond its scheduled termination date of June 30, 2009. The Commission consolidated the decoupling issues into the general rate case proceedings and granted an interim extension of the pilot decoupling mechanism pending the outcome of these proceedings.

321 (11) Avista's decoupling mechanism has enhanced the Company's conservation efforts and, with modifications discussed in the body of this Order that better align the Company's recovery of its lost margins with the impacts of its own programmatic and non-programmatic conservation efforts, it can continue to do so in a manner that balances the interests of ratepayers and the Company.

322 (12) Forty-five percent (45%) of Schedule 101's lost margins are attributable to Avista's programmatic and non-programmatic conservation efforts.

323 (13) The rates, terms, and conditions of service that result from adoption of the Settlement Stipulation attached to and incorporated into the body of this Order as if set forth in full, coupled with the Commission's determinations of contested issues as discussed in the body of this order, result in rates for Avista's electric service and natural gas service that are fair, just, reasonable, and sufficient.

324 (14) The rates, terms, and conditions of service that result from the Commission's determinations in this Order are neither unduly preferential nor discriminatory.

CONCLUSIONS OF LAW

325 Having discussed above all matters material to this decision, and having stated detailed findings, conclusions, and the reasons therefore, the Commission now makes the following summary conclusions of law, incorporating by reference pertinent portions of the preceding detailed conclusions:

326 (1) The Washington Utilities and Transportation Commission has jurisdiction over the subject matter of, and parties to, these proceedings.

327 (2) The rates proposed by tariff revisions filed by Avista on January 23, 2009, and suspended by prior Commission order, were not shown to be fair, just or reasonable and should be rejected.

328 (3) The existing rates for electric service and gas service that Avista provides in Washington are insufficient to yield reasonable compensation for the services rendered.

329 (4) Avista requires relief with respect to the rates it charges for electric service and gas service provided in Washington.

330 (5) The Settlement Stipulation filed by the Parties to this proceeding on September 4, 2009, if approved subject to the conditions stated in this Order requiring adjustment to power costs to reflect the Commission's disallowance of recovery of costs associated with the Lancaster Power Purchase Agreement (PPA), would result in rates for Avista that are fair, just, reasonable and sufficient, and are neither unduly preferential nor discriminatory. The Settlement Stipulation is attached to this Order as Appendix A, and incorporated by reference as if set forth in full in the body of this Order.

331 (6) The Partial Settlement Stipulation should be approved by the Commission, subject to the conditions stated in this Order requiring adjustment to power costs to reflect the Commission's disallowance of recovery of costs associated with the Lancaster PPA, as a reasonable resolution of the issues presented. Approval and adoption of the Partial Settlement Stipulation, as conditioned, is in the public interest.

332 (7) The Low Income Rate Assistance Program portion of Schedules 91 and 191 should be increased in the Company's electric and gas tariffs to levels specified in the Settlement Stipulation: 9.0 percent for electricity and 1.75 percent for gas.

333 (8) Avista should be allowed to recover in rates additional revenue as reflected in the Settlement Stipulation, the uncontested adjustments summarized in Table 2A for electric service and Table 2B for natural gas service, and the Commission's resolution of contested adjustments as detailed in the body of this Order and summarized in Table 4 for electric service and Table 5 for natural gas service.

334 (9) Avista's maximum recovery of lost margin via the decoupling mechanism should be limited to forty-five percent (45%) of Schedule 101's lost margins, which the Commission finds are attributable to Avista's programmatic and non-programmatic conservation efforts.

335 (10) To better match benefits to those paying the costs, the Commission should modify the decoupling mechanism effective with the target set as a result of the Company's 2009 natural gas Integrated Resource Plan, by setting and measuring achievement under the DSM target with DSM savings for Idaho removed so that only DSM savings for Washington are considered.

336 (11) The lost margin calculation under Avista's decoupling mechanism should be adjusted to remove the effect of customer migration between Schedule 101 and Schedule 111 because there is no recovery of DSM lost margin from Schedule 111 customers.

337 (12) Avista should be required to make such compliance and subsequent filings as are necessary to effectuate the terms of this Order.

338 (13) The Commission should retain jurisdiction to effectuate the terms of this Order.

ORDER

THE COMMISSION ORDERS:

339 (1) The tariff revisions Avista Corporation, d/b/a Avista Utilities, filed on January 23, 2009, and suspended by prior Commission order, are rejected.

340 (2) The Settlement Stipulation filed by the parties on September 4, 2009, is approved and adopted as being in the public interest, subject to the Commission's determination that the costs associated with the Lancaster PPA must be removed, necessitating a rerun of the AURORA power cost model during the compliance phase of this proceeding and an adjustment to the power cost set forth in the Settlement Stipulation for recovery in rates.

341 (3) Avista Utilities is authorized and required to file tariff sheets that are necessary and sufficient to effectuate the terms of this Order. The required tariff sheets must be filed no later than 5:00 p.m. on Monday, December 28, 2009, to give the Commission an opportunity to review the Company's compliance filing, and shall bear an effective date of January 1, 2010.

342 (4) Avista Utilities is authorized to defer the costs associated with the Lancaster PPA for a period not to exceed twenty-four (24) months from the beginning of the Lancaster contract. If the Company files a general rate case seeking to recover Lancaster contract costs during the twenty-four (24) month period, the deferral ends on the effective date of the Commission's Final Order in such proceeding. This authorization for deferral is conditioned on the Company filing a petition for accounting treatment consistent with the terms and requirements of this Order.

343 (5) Increases to levels specified in the Settlement Stipulation are approved for the Low Income Rate Assistance Program portion of Schedules 91 and 191.

344 (6) Avista Utilities is authorized to continue its decoupling mechanism, as modified by the terms of this Order. Deferrals recorded since June 30, 2009, are required to be adjusted as if deferred under the modified mechanism and are subject to recovery on that basis.

345 (7) Avista Utilities must convene a collaborative to discuss evaluation, measurement and verification (EM&V) methodology for its DSM programs and file a plan in accordance with this Order by September 1, 2010.

346 (8) Avista Utilities must also file by September 1, 2010, a separate report investigating the impact of its decoupling mechanism on low-income customers.

347 (9) The Commission Secretary is authorized to accept by letter, with copies to all parties to this proceeding, such filings as Avista Utilities makes to comply with the terms of this Order.

348 (10) The Commission retains jurisdiction to effectuate the terms of this Order.

Dated at Olympia, Washington, and effective December 22, 2009.

WASHINGTON STATE UTILITIES AND TRANSPORTATION COMMISSION

JEFFREY D. GOLTZ, Chairman

PATRICK J. OSHIE, Commissioner

PHILIP B. JONES, Commissioner

NOTICE TO PARTIES: This is a Commission Final Order. In addition to judicial review, administrative relief may be available through a petition for reconsideration, filed within 10 days of the service of this order pursuant to RCW 34.05.470 and WAC 480-07-850, or a petition for rehearing pursuant to RCW 80.04.200 and WAC 480-07-870.

APPENDIX A

MULTI-PARTY PARTIAL SETTLEMENT STIPULATION
DOCKETS UE-090134, UG-090135 & UG-060518

**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)* PARTIAL SETTLEMENT STIPULATION

I. PARTIES

This Partial Settlement Stipulation is entered into pursuant to WAC 480-07-730(2) by Avista Corporation ("Avista" or the "Company"), the Staff of the Washington Utilities and Transportation Commission ("Staff"), the Public Counsel Section of the Washington Office of Attorney General ("Public Counsel"), the Industrial Customers of Northwest Utilities ("ICNU"), the Northwest Industrial Gas Users ("NWIGU"), and The Energy Project (jointly referred to herein as the "Parties"). Together with the NW Energy Coalition ("NWEC"),[1] the foregoing represent all parties in these consolidated dockets. The Parties agree that this Partial Settlement

[1] The NW Energy Coalition ("NWEC") is not a party to this Stipulation but does not oppose the Settlement among the Parties. NWEC did not take a position in prefiled testimony with respect to any of the issues that are the subject of this Stipulation.

Stipulation is in the public interest and should be adopted by the Commission as a resolution of those issues identified below, which relate to cost of capital, power supply, rate spread and rate design, and low-income ratepayer assistance. This Partial Settlement Stipulation is limited to its terms and leaves other matters for further litigation or resolution, including revenue requirement, power supply (Lancaster issues), Schedule 101 gas rate design (including customer charges), and decoupling issues.

II. INTRODUCTION

On January 23, 2009, Avista filed with the Washington Utilities and Transportation Commission ("Commission") revisions to its currently effective Tariff WN U-28, Electric Service in Docket UE-090134, and revisions to its currently effective Tariff WN U-29, Gas Service in Docket UG-090135. The proposed revisions would have implemented a general rate increase of $69.8 million, or 16.0 percent, for electric service and $4.9 million, or 2.4 percent, for gas service. The Commission suspended the filings on February 3, 2009, consolidated the two dockets, and, following a pre-hearing conference held on February 24, 2009, set the dockets for hearing in October 2009.

On April 30, 2009, Avista filed a petition to consolidate Docket UG-060518, a matter regarding the Company's pilot decoupling mechanism, with the rate case proceeding. The Company's petition also sought to extend the pilot beyond its scheduled termination date of June 30, 2009. On May 15, 2009, the Commission issued Order No. 06, granting the petition to consolidate. Subsequently, on June 30, 2009, the Commission, in Order 07, granted Avista's request for approval of an interim extension of the existing decoupling mechanism.

All parties conducted settlement discussions in this docket on July 24, 2009, and during the week of August 24-28, 2009. These discussions resulted in the resolution of issues, as among themselves, in the areas of cost of capital, power supply, rate spread and rate design, as well as funding under the low-income ratepayer assistance program (LIRAP), as set forth herein.

III. AGREEMENT

A. Revised Revenue Requirement

The Parties agree to the revenue requirement adjustments to both the filed electric and natural gas cases, as described in Attachment A, which consists of a summary of revenue requirement adjustments for electric and natural gas. The summaries also identify, for reference purposes only, the remaining contested adjustments to revenue requirement. After giving effect to this Stipulation, Avista recommends a revenue requirement of $38.61 million for electric and $3.14 million for gas, revised downward from $69.76 million (electric) and $4.92 million (gas), respectively. Non-company parties to this Stipulation continue to recommend a lower revenue requirement, based on the remaining contested issues, and all Parties may continue to litigate these disputed items.

1. Cost of Capital

The Parties agree to a 10.2% return on equity, with a 46.5% common equity ratio, and adopt the capital structure and resulting rate of return as set forth below.

Agreed-upon			
Cost of Capital	Percent of Total capital	Cost	Component
Total Debt	53.50%	6.57%	3.51%
Common Equity	46.50%	10.20%	4.74%
TOTAL	100.00%		8.25%

2. <u>Power Supply-Related Adjustments</u>

The Parties agree to the following adjustments related to power supply:

(a) Adjust (Natural Gas) Fuel Costs. This adjustment reflects a pro forma period natural gas price of $5.61/Dth (at Stanfield) for natural gas-fired generation for the unhedged portion of the 2010 generation. This adjustment also includes the actual 2010 calendar-year wholesale electric and natural gas transactions entered into through July 3, 2009. For purposes of calculating power costs for the rate year, the Parties agree that there shall be no further changes to the price of natural gas or to the electric or natural gas transactions in this case.

(b) Hydro Filtering. This adjustment removes the power supply expense from the 50-year average for months when the hydro generation was either higher or lower by more than one standard deviation from the average generation for that month.

(c) Retail Load Adjustment. This adjustment reduces, by three percent (3%) (from 5.1% to 2.1%), the increase in pro forma system loads (January 2010 through December 2010), used for purposes of adjusting test period loads in order to determine pro forma year power supply expense levels.

(d) Colstrip Availability. The Parties agree to use the five (5)-year average equivalent availability factor for Colstrip, for the period ending December 31, 2007, as reflected in the Company's filing.

(e) WNP-3 Contract Adjustment. The Parties agree to use the level of WNP-3 O&M costs approved by the Commission in Cause No. U-86-99, and as reflected in the Company's filing.

(f) Kettle Falls Fuel Adjustment. This adjustment reduces available Kettle Falls generation to reflect a lower level of fuel availability for the plant in 2010.

3. **Pro Forma O&M Generation.**

The Parties agree to the adjustment recommended by Staff and Public Counsel to remove $2,372,000 of 2010 pro forma period costs included in the Company's filing for generation O&M.

4. **Remaining Contested Revenue Requirement Adjustments.**

Attachment A provides a summary listing of remaining contested adjustments. This summary is provided for reference purposes only and no party to this Stipulation waives its rights to raise issues not included in the list which have not expressly been resolved in the Stipulation.

B. Rate Spread/Rate Design

The Parties agree to the following settlement of issues related to rate spread and rate design:

1. Electric Services:

(a) Rate Spread – The Parties agree to apply an equal percentage increase to all electric service schedules for purposes of recovering the Company's revenue requirement ultimately determined by the Commission.

(b) Rate Design –

(i) The residential basic charge will be increased from $5.75 to $6.00 per month.

(ii) Except for Extra Large General Service Schedule 25, the increases to other customer and demand charges will be as proposed in the Company's original filing.

(iii) For Extra Large General Service Schedule 25,

- The minimum charge will be increased from $10,000 to $11,000 per month.
- The excess demand charge will be increased from $3.00 to $3.50 per kVa.
- The voltage discount for over 60kV will be increased to $1.00/kVa and for over 115kV to $1.20/kVa.
- A uniform percentage increase will be applied to the first two energy block rates, and the increase to the third energy block rate will be equal to 0.5 times the percentage increase applied to the first two blocks.

2. <u>Gas Service</u>:

(a) <u>Rate Spread</u> –

(i) The Parties agree to apply an equal percentage of margin increase to all gas service schedules, except Schedule 146 (Transportation).

(ii) Schedule 146 (Transportation) will receive two-thirds of an equal margin increase, with the residual one-third allocated proportionately (based on margin) to the other schedules.

(b) <u>Rate Design</u> –

(i) The rates within Schedules 111 and 112 will be increased to maintain the present break-even usage level between Schedules 101 and 111, in order to minimize future customer schedule shifting, as proposed in the Company's filing (Page 23 of Hirschkorn Direct Testimony). The design of the rates under

Schedule 101 in this proceeding will not be conditioned or dependent upon the rates under Schedules 111 and 112.

(ii) The rates under Schedule 146 (including the customer charge) will be increased on an equal percentage basis.

(iii) This Partial Settlement Stipulation does not resolve Schedule 101 gas rate design issues (including customer charges).

C. Low Income Bill Assistance Funding

The Parties agree to increase rates for the LIRAP (Low Income Ratepayer Assistance Program) portion of the Tariff riders (Schedules 91 and 191), expressed as a percentage, by the greater of:

1. For Electric – the overall percentage increase in base revenue approved for electric or 9.0%.

2. For Gas – the overall percentage increase in base revenue approved for gas or 1.75%.

IV. EFFECT OF THE PARTIAL SETTLEMENT STIPULATION

A. Binding on Parties.

The Parties agree to support the terms of the Partial Settlement Stipulation throughout this proceeding, including any appeal, and recommend that the Commission issue an order adopting the Partial Settlement Stipulation contained herein. The Parties understand that this Partial Settlement Stipulation is subject to Commission approval. The Parties agree that the Partial Settlement Stipulation represents a compromise in the position of the Parties. As such, conduct, statements and documents disclosed in the negotiation of this Partial Settlement Stipulation shall not be admissible evidence in this or any other proceeding.

B. Integrated Terms of Partial Settlement.

The Parties have negotiated this Partial Settlement Stipulation as an integrated document. Accordingly, the Parties recommend that the Commission adopt this Partial Settlement Stipulation in its entirety. Each Party has participated in the drafting of this Partial Settlement Stipulation, so it should not be construed in favor of, or against, any particular Party.

C. Procedure.

The Parties shall cooperate in submitting this Partial Settlement Stipulation promptly to the Commission for acceptance. The Parties shall make available a witness or representative in support of this Partial Settlement Stipulation. The Parties agree to cooperate, in good faith, in the development of such other information as may be necessary to support and explain the basis of this Partial Settlement Stipulation and to supplement the record accordingly.

At time of hearing, the Parties agree to stipulate into evidence the pre-filed direct testimony and exhibits of the Parties as they relate to the stipulated issues, together with such evidence in support of the Stipulation as may be offered at the time of the hearing on the Partial Settlement.

If the Commission rejects all or any material portion of this Partial Settlement Stipulation, or adds additional material conditions, each Party reserves the right, upon written notice to the Commission and all parties to this proceeding within seven (7) days of the date of the Commission's Order, to withdraw from the Partial Settlement Stipulation. If any Party exercises its right of withdrawal, this Partial Settlement Stipulation shall be void and of no effect, and the Parties will support a joint motion for an expedited procedural schedule to address the issues that would otherwise have been settled herein.

D. Advance Review of News Releases.

All Parties Agree:

(i) to provide all other Parties the right to review in advance of publication any and all announcements or news releases that any other Party intends to make about the Partial Settlement Stipulation. This right of advance review includes a reasonable opportunity for a Party to request changes to the text of such announcements. However, no Party is required to make any change requested by another Party; and

(ii) to include in any news release or announcement a statement that the recommendation to approve the settlement is not binding on the Commission itself.

E. <u>No Precedent</u>.

The Parties enter into this Partial Settlement Stipulation to avoid further expense, uncertainty, and delay. By executing this Partial Settlement Stipulation, no Party shall be deemed to have accepted or consented to the facts, principles, methods or theories employed in arriving at the Partial Settlement Stipulation, and, except to the extent expressly set forth in the Partial Settlement Stipulation, no Party shall be deemed to have agreed that such a Partial Settlement Stipulation is appropriate for resolving any issues in any other proceeding.

F. <u>Public Interest</u>.

The Parties agree that this Partial Settlement Stipulation is in the public interest and should be adopted by the Commission.

G. <u>Execution</u>.

This Partial Settlement Stipulation may be executed by the Parties in several counterparts and as executed shall constitute one Partial Settlement Stipulation.

Entered into this 4th day of September, 2009.

Company: By: ____________________

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

Staff: By: ____________________

Gregory J. Trautman
Assistant Attorney General

Public Counsel: By: ____________________

Simon ffitch
Senior Assistant Attorney General
Public Counsel Section
Washington Attorney General

ICNU: By: ____________________

S. Bradley Van Cleve
Davison Van Cleve, P.C.

NWIGU: By: ____________________

Chad M. Stokes
Cable Huston Benedict
Haagensen & Lloyd LLP

The Energy Project: By: ____________________

Ronald Roseman
Attorney at Law

Entered into this 4th day of September, 2009.

Company: By: ______________________

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

Staff: By: Gregory J. Trautman

Gregory J. Trautman
Assistant Attorney General

Public Counsel: By: ______________________

Simon ffitch
Senior Assistant Attorney General
Public Counsel Section
Washington Attorney General

ICNU: By: ______________________

S. Bradley Van Cleve
Davison Van Cleve, P.C.

NWIGU: By: ______________________

Chad M. Stokes
Cable Huston Benedict
Haagensen & Lloyd LLP

The Energy Project: By: ______________________

Ronald Roseman
Attorney at Law

Entered into this 2nd day of September, 2009.

Company: By: ______________________________

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

Staff: By: ______________________________

Gregory J. Trautman
Assistant Attorney General

Public Counsel: By: ______________________________

Simon ffitch
Senior Assistant Attorney General
Public Counsel Section
Washington Attorney General

ICNU: By: ______________________________

S. Bradley Van Cleve
Davison Van Cleve, P.C.

NWIGU: By: ______________________________

Chad M. Stokes
Cable Huston Benedict
Haagensen & Lloyd LLP

The Energy Project: By: ______________________________

Ronald Roseman
Attorney at Law

Entered into this ____ day of September, 2009.

Company:	By: ______________________________ David J. Meyer VP, Chief Counsel for Regulatory and Governmental Affairs
Staff:	By: ______________________________ Gregory J. Trautman Assistant Attorney General
Public Counsel:	By: ______________________________ Simon ffitch Senior Assistant Attorney General Public Counsel Section Washington Attorney General
ICNU:	By: S Bradley Van Cleve S. Bradley Van Cleve Davison Van Cleve, P.C.
NWIGU:	By: ______________________________ Chad M. Stokes Cable Huston Benedict Haagensen & Lloyd LLP
The Energy Project:	By: ______________________________ Ronald Roseman Attorney at Law

Entered into this ____ day of September, 2009.

Company: By: ______________________________

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

Staff: By: ______________________________

Gregory J. Trautman
Assistant Attorney General

Public Counsel: By: ______________________________

Simon ffitch
Senior Assistant Attorney General
Public Counsel Section
Washington Attorney General

ICNU: By: ______________________________

S. Bradley Van Cleve
Davison Van Cleve, P.C.

NWIGU: By: ______________________________

Chad M. Stokes
Cable Huston Benedict
Haagensen & Lloyd LLP

The Energy Project: By: ______________________________

Ronald Roseman
Attorney at Law

Entered into this 3rd day of September, 2009.

Company: By: ____________

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

Staff: By: ____________

Gregory J. Trautman
Assistant Attorney General

Public Counsel: By: ____________

Simon ffitch
Senior Assistant Attorney General
Public Counsel Section
Washington Attorney General

ICNU: By: ____________

S. Bradley Van Cleve
Davison Van Cleve, P.C.

NWIGU: By: ____________

Chad M. Stokes
Cable Huston Benedict
Haagensen & Lloyd LLP

The Energy Project: By: ____________

Ronald Roseman
Attorney at Law

Avista Utilities
Docket Nos. UE-090134, UG-090135, and UG-060518
Electric

			$000s
Revenue Requirement As Filed by Avista			$ 69,762
Agreed Upon Adjustments:			
	Cost of Capital		
(1)	Return On Equity = 10.2% Cost of Debt = 6.57%		(6,152)
(2)	Common Equity = 46.5%		(815)
	Power Supply		
(3)	Power Supply Adj - Updated Gas Prices & Contracts	(18,100)	
(4)	Power Supply Adj - Filtering Adjustment	(729)	
(5)	Power Supply Adj - Retail Load Adjustment	(9,091)	
(6)	Power Supply Adj - Colstrip Availability (No Adjustment to Original Filing)	0	
(7)	Power Supply Adj - WNP-3 (No Adjustment to Original Filing)	0	
(8)	Adjust Kettle Falls Fuel Volume	383	
	Total Power Supply Adjustments		(27,537)
(9)	Pro Forma O&M Generation		(2,372)

Contested Adjustments:

Lancaster Prudence
Labor
Capital Additions
CDA Tribe Settlement
Asset Management
Information Services
Colstrip - Mercury Emission
Incentives
Pension Expense
Insurance
Director & Officers Insurance
Board of Directors Fees
Board Meeting Expenses
Property Taxes
Customer Deposits
Injuries & Damages
Spokane River Relicensing
Dues (Edison Electric Institute)
Restate Debt Interest
Production Property Adjustment

Avista Utilities
Docket Nos. UE-090134, UG-090135, and UG-060518
Natural Gas

		$000s
Revenue Requirement As Filed by Avista		$ 4,918
Agreed Upon Adjustments:		
Cost of Capital		
(1)	Return On Equity = 10.2% Cost of Debt = 6.57%	(1,088)
(2)	Common Equity = 46.5%	(145)

Contested Adjustments:

Labor
Capital Additions
Asset Management
Information Services
Incentives
Pension Expense
Insurance
Director & Officers Insurance
Board of Directors Fees
Board Meeting Expenses
Property Taxes
Customer Deposits
Injuries & Damages
Restate Debt Interest
Dues (American Gas Association)

Other Issues:
The continuation of the decoupling mechanism remains contested.

APPENDIX B
SUMMARY OF REQUIRED ACTIONS[435]
DOCKETS UE-090134, UG-090135 & UG-060518

REQUIREMENT	DEADLINE	ORDER PARAGRAPH(S)
Compliance Filing – New Tariffs[436]	December 28, 2009	337, 340 & 341
Decoupling – Convene Collaborative on Evaluation, Measurement and Verification (EM&V) Issues	1st Qtr 2010	305 & 345
Decoupling – File Plan Evaluation, Measurement and Verification (EM&V) Plan for DSM Programs	September 1, 2010	305 & 345
Decoupling – File Low Income Report	September 1, 2010	306 & 346
Lancaster – Petition for Accounting Treatment (Deferral of Costs)	Prior to Next General Rate Case	226-230 & 342
Lancaster – Affiliated Interest Filing	Prior to Next General Rate Case	207-214, 226 & 231
Lancaster – RCW 80.80 Compliance Filing (Greenhouse Gas Emissions)	Prior to Next General Rate Case	207, 215-221, 223, 226 & 232

[435] This Appendix provides a summary of actions the Company must take under Order 10 in Dockets UE-090134, UG-090135, and UG-060518. This summary is provided for the convenience of the parties and is not intended to replace or modify the requirements of Order 10 or the parties' Partial Settlement Stipulation. If this summary inadvertently does not include requirements contained in the order, the parties are not excused from complying with all requirements of the order.

[436] Filing of new tariffs requires Avista to re-run the AURORA power cost model (*see* Table 4, note 1) and recalculation of production property adjustment (*see* Table 4, note 2).