BEFORE THE WASHINGTON UTILITIES AND

TRANSPORTATION COMMISSION

WUTC V. AVISTA CORPORATION d/b/a AVISTA UTILITIES

DOCKET NOS. UE-050482 AND UG-050483

DIRECT TESTIMONY OF MERTON R. LOTT (MRL-1T)

ON BEHALF OF

PUBLIC COUNSEL

August 26, 2005

DIRECT TESTIMONY OF MERTON R. LOTT (MRL-1T)

LOTT'S EXHIBIT LIST

Exhibit No. ___ (MRL-2)	Electric Adjustment Summary
Exhibit No. ___ (MRL-3)	Comparison Lott to Avista and Settlement
Exhibit No. ___ (MRL-4)	Electric Power Supply Adjustment PF1, PC Adjustment Part One
Exhibit No. ___ (MRL-5)	Electric Power Supply PF1, PC Adjustment Part Two
Exhibit No. ___ (MRL-6)	Idaho Public Utilities Commission, Case Nos. AVU-E-04-1, AVU-G-04-1, Order No. 29602

I. INTRODUCTION AND SUMMARY

Q. Please state your name and address.

A. My name is Merton R. Lott. My business address is 10809 103rd St. SW, Tacoma, Washington.

Q. By whom are you employed?

A. I am self employed as a consultant concentrating on utility rate work.

Q. On whose behalf are you appearing?

A. I have been retained by the Public Counsel Section of the Office of the Attorney General of the State of Washington ("Public Counsel") to review certain aspects of the recent rate application of Avista Corporation doing business as Avista Utilities ("Avista" or "Company").

Q. What was your assignment in this proceeding?

A. I was hired to review per books costs and adjustments related to power production, and other costs that are related to a proper Power Cost Adjustment mechanism (PCA). In addition, I was asked to review and formulate a position on Avista's Energy Recovery (ERM). My work is being coordinated with that of Mr. James Dittmer who is also appearing on behalf of Public Counsel. Mr. Dittmer's testimony and exhibits include a combined summary of all Public Counsel's revenue requirement and cost of capital recommendations.

Q. Please summarize your testimony.

A. I am proposing several adjustments to Avista's revenue requirement. My adjustments, which are summarized in Exhibit___ (MRL-2), cumulatively reduce Avista's originally filed electric revenue requirement by over $6 million. I am aware that there is a proposed settlement between Avista, the Washington Utilities and Transportation Commission Staff (hereinafter "Staff."), and other parties. Some of my adjustments to Avista's revenue requirement appear to have been reflected within the proposed settlement. However, as I describe below, I post several significant adjustments that are incremental to those reflected within the Avista/Staff settlement and reduce the revenue requirement included in the Settlement by approximately $5 million. I also comment on production adjustments included in Avista's initial filing as well as within the settlement agreement.

While I make some references to the settlement, I will reserve detailed comment on the settlement proposal until after I have reviewed the supporting testimony and had the opportunity to conduct discovery.

The second portion of my testimony presents my recommendations for modifying Avista's presently authorized Energy Recovery Mechanism (ERM). I discuss my concerns with the changes to the ERM proposed by Avista and recommend reforms which will establish a properly structured Power Cost Adjustment (PCA) mechanism for Avista to replace the current ERM.

Q. Please identify the exhibits which support your findings and testimony.

A. Exhibit ___ (MRL-2) contains a summary of the adjustments I propose in this case. Each column (A) through (I) displays either a replacement for an adjustment proposed by Avista in its initial filing, or in two instances, new adjustments being proposed by me. Columns (A), (B) & (I)) present adjustments I propose which are also addressed in the settlement agreement. Each of the columns in Exhibit ___ (MRL-2) are a replacement for the adjustments shown in the Company's columns from Mr. Falkner's Exhibit ___(DMF-2), pages 4-9. For ease of reference, I have reflected the Company's adjustment column letters/numbers just below the adjustment titles in Exhibit.___ (MRL-2).

Exhibit ___ (MRL-3) compares each of the adjustments reflected within Exhibit ___ (MRL-2) to the adjustments included in the Company's initial filing as well as to the adjustments as I understand them in the settlement between Commission staff and the Company. This exhibit will be updated if necessary upon review of more detailed information on the settlement adjustments.

Exhibit ___ (MRL-4) is my analysis of the power supply pro forma adjustment (PF1) included in the settlement agreement. This reflects my current understanding of the contents of the agreed upon adjustments to revenue requirement. I will modify this exhibit in rebuttal, as necessary, when more complete information is available. My testimony will include a description and support of those adjustments which I accept or reject, as well as identify those which are related to the Aurora model and which are beyond the scope of my examination.

Exhibit ___ (MRL-5) is a summary of the additional adjustments I am proposing to the power supply adjustment. Again, after I receive more information about individual adjustments in the settlement this exhibit may change.

Exhibit ___ (MRL-6) is a copy of the relevant pages of the Idaho Public Utilities Commission order in Avista's 2004 general rate case.

Q. Did your review encompass a review of the model used to calculate Avista's proposed Power Supply Adjustment (PF1)?

A. No. The scope of my examination does not include an analysis of the Company's production cost simulation run – commonly referred to as the Aurora model. Consequently, at this time I have no position on whether or not the Aurora model or Avista's use of the model properly measures variable power supply costs.

II. QUALIFICATIONS

Q. Please state your educational background.

A. I graduated from Seattle University with a Bachelor of Arts in Business Administration, with an Accounting Major, in 1973. Subsequent to my graduation I passed the CPA exam and obtained a Certificate of Public Accounting (CPA) in the State of Washington which I maintained for over twenty years. Currently I do not possess a certificate. While employed with the Washington Utilities and Transportation Commission, I attended numerous classes and conferences on regulation, accounting and finance. These classes met the continuing education requirements for my CPA. Further, as one of the Commission's representatives to the National Association of Regulatory Utility Commissioners ("NARUC") subcommittee on accounts from 1991 until my retirement in 2004, I attended and participated in numerous semiannual conferences held by the subcommittee.

Q. Please summarize your professional experience.

A. Subsequent to graduation from Seattle University, I was hired by the Washington Utilities and Transportation Commission as a U&T Accounting Analyst in the Accounting and Finance section of the Utilities and Accounting Division. In 1986, I was promoted to a Revenue Requirement Specialist 5 in the Accounting section, where I was the supervisor of all accountants assigned to the electric industry. During the 1974 -- 1990 period, I performed various phases of accounting and financial analysis of both utility and transportation companies. I served as the lead auditor in rate audits of the major companies in all industries regulated by the Commission, including multiple cases with the three electric firms regulated by the Commission. Included in those proceedings were most of Puget Sound Power & Light's (PSE's predecessor) Energy Cost Adjustment Clause (ECAC) proceedings as well as Washington Water Power's proposed Power Cost Adjustment petitions.

In 1990 I transferred to the Regulatory Affairs Section as the Commission's Accounting Advisor where I was subsequently promoted into a Washington Management Service (WMS) position. During this period, I advised the Commissioners, Administrative Law Judges, and Review Judges on all formal proceedings that had financial and/or accounting issues. Several major rate proceedings, including those of Washington Natural Gas, Puget Sound Power & Light, US West, and Waste Management, were filed while I held this position. Several merger petitions also were processed during this time frame. Also during this period, Puget Sound Power & Light filed for a Periodic Rate Adjustment Mechanism (PRAM) which combined a decoupling and PCA mechanism, during this time period.

In June 1996, I was promoted to Gas Industry Coordinator where I reported to the Director of Regulatory Services. In this position I supervised the Regulatory Service Division's staff assigned to the gas industry and coordinated filings in that industry. During this period the gas section processed several tariff filings, rulemakings, and policy development proceedings including several gas general rate cases. During this period I also assisted the Commission as their accounting advisor in several telephone proceedings. In addition, I participated in several electric filings, and was the lead analyst in the PacifiCorp general rate filing in Docket UE-991832.

In January 2001, when the Regulatory Services Division consolidated the gas and electric departments, I became the Energy Industry Coordinator. During this period I worked with the Assistant Director of Energy. Further, I was the lead staff on a series of Puget Sound Energy (PSE) petitions and tariff filings, including the interim and general rate cases in Dockets UE-011570 and UG-011571. This proceeding was resolved with an omnibus all-party settlement involving over 30 parties. These settlements included: the use of am “equity tracker”—a hypothetical capital structure and a tariff mechanism designed to insure that PSE would obtain the desired capital structure over a reasonable time period (settled in the interim rate case); the development of PSE’s PCA and “power cost only rate case” (PCORC) mechanism; a fundamental change in PSE’s electric line extension policy; consensus agreements on conservation and low income tariffs; a consensus between PSE and the numerous intervening cities regarding line undergrounding tariffs; a service quality index, and settlements on interim and general rate increases for gas and electric. Just prior to my retirement on April 30, 2004, I was the staff lead in PSE’s first PCORC filing.

Subsequent to my retirement, I signed a contract with the Commission as an accounting advisor and assisted them on the PSE general rate case in 2004.

III. REVENUE REQUIRMENT ADJUSTMENTS: NON-POWER SUPPLY ISSUES

A. Colstrip 3 AFUDC Elimination, Column (A); Colstrip Common AFUDC, Column (B)

Q. Would you now discuss the adjustments shown in the two Columns (A) and (B) of Exhibit ___ (MRL-2)?

A. Yes. The Colstrip 3 AFUDC Eliminations, and Colstrip Common AFUDC relate to the regulatory treatment of Avista's (fka Washington Water Power or WWP) investment in Colstrip during the time Colstrip 3 and 4 were being constructed. An accounting problem and a resulting allocation problem stem from divergent treatment of these investments during their construction phase in the three jurisdictions that regulated WWP at that time (Washington, Idaho, and FERC). Specifically, the eliminations adjustment deals with the fact that each of the state jurisdictions included portions of Colstrip 3 in rate base during its construction, and thus, were eligible for differing levels or amounts of an Allowance for Funds Used During Construction ("AFUDC") to be included within Plant in Service.

Q. Please discuss the concept and mechanics of AFUDC construction accounting.

A. Utility construction projects can take months or years to complete. During the construction phase, utilities incur significant amounts of carrying costs on the funds used to construct these projects. These carrying costs include a rate of return on the equity portions of the financing and the interest rate on debt financing. In recognition of this dilemma, utilities that are not allowed to include construction work in progress ("CWIP") in rate base are allowed to "capitalize," or add these carrying costs to the cost of the construction project. Pursuant to the accounting prescribed by this Commission, utilities are instructed to capitalize the carrying cost of funds used to construct the project, adding the capitalized carrying costs to the cost of the construction. In Commission ratemaking these funds are assumed to include portions of each part of the utility's total capitalization. These capitalized carrying costs are known as AFUDC. Thus, the capitalization of AFUDC increases the total cost of constructing a facility that ultimately leads to a higher rate base value and higher depreciation expense when the facility goes into service.

Q. Are utilities sometimes permitted to include CWIP in rate base?

A. Yes. In a few instances and circumstances, utilities have been permitted to include a facility in rate base even during its construction phase. In those instances, utilities are not permitted to capitalize AFUDC to the portion of the construction project included in rate base, inasmuch as they are already earning a "cash" return on the facility. To allow them to also capitalize the financial carrying cost of the facility for later inclusion in rate base would result in an over-recovery - a "double dip." The Colstrip project was allowed to be included in rate base – in varying amounts – by the two state jurisdictions that regulate Avista.

Q. How did Avista account for the differences in the amount of Colstrip CWIP allowed in rate base by the two different state jurisdictions?

A. These rate base inclusions by the two different state jurisdictions were for different amounts and for different periods of time. In order to accommodate the various rate treatments, WWP booked AFUDC following the normal process and then calculated by state the amount of that AFUDC that had been recovered through rates during the time of construction. These AFUDC "eliminations" were then booked as an offset or reduction to the Plant in Service accounts. These rate base inclusions of Construction Work in Progress were done in Washington prior to a court decision which stopped this Commission from including Construction Work in Progress in rate base. The elimination adjustment I am referring to simply reallocates this credit portion of the plant balance between the two state jurisdictions (Washington and Idaho).

Another difference between the various jurisdictions occurred with regard to AFUDC accrued on Colstrip "common" facilities. By "common facilities," I am referring to facilities located at the Colstrip generating station that are built to serve or accommodate the four Colstrip units operating in various combinations. Colstrip Common AFUDC represents accruals WWP made because the two state jurisdictions (Washington and Idaho) decided that only a portion of the Colstrip Common plant (common between units 3 and 4 or between units 1, 2, 3 and 4) could be placed in rate base at the time Colstrip 3 was placed in service. Pursuant to the FERC Uniform System of Accounts (USOA), AFUDC on common facilities is to cease once the first unit at the site goes into service. However, since the Washington jurisdiction only allowed a portion of the Colstrip common facilities in rate base at the time the Colstrip 3 unit went into service, WWP was allowed to continue to capitalize AFUDC on the Colstrip common facilities not allowed in rate base. The AFUDC accrual associated with Colstrip common facilities initially excluded from the Washington jurisdictional rate base were never booked to, or added to, WWP's recorded plant in service account. Thus a "rate case" adjustment is necessary to include the net unamortized balance of Colstrip Common AFUDC accounting that the WUTC allowed – but which Avista never recorded to plant in service in its books.

In summary, both of these adjustments have to do with plant in service and accumulated depreciation as ordered in the State of Washington, and thus it is appropriate to consider them in the same fashion as plant in service for the Colstrip plants.

Q. How did Avista calculate these adjustments and what are your modifications?

A. Avista calculated these adjustments by looking at the 2006 balances of both the eliminations and the Colstrip Common AFUDC. As the AFUDC that was being eliminated is included in rate base balances on a 2004 average basis, it is only appropriate to recalculate the allocation of these eliminations at the 2004 level also. With respect to the Colstrip Common AFUDC it is also a part of the plant in service on a Washington basis and should be included in rate base on the same basis as all Colstrip common plant in service, i.e., on a 2004 basis. The result of these two modifications is first, to increase the eliminations allocated to Washington by $441,000, and second, to increase the AFUDC on the Common plant by $63,000. As shown in Exhibit ___ (MRL-3) the settlement agreement appears to include the same adjustments I propose.

B. Kettle Falls Disallowance, Column (C), Exhibit ___ (MRL-2)

Q. Refer now to your adjustment in Column (C), Kettle Falls Disallowance, please describe what this adjustment is intended to represent.

A. Kettle Falls is a steam generating plant owned by Avista located near Kettle Falls in northeast Washington State. The Kettle Falls plant is fueled by wood products known as hog fuel. The Kettle Falls generating plant was first placed into service in October 1983. Based on significant concerns regarding whether the continuation of the Kettle Falls project was a least cost option, and concerns related to the fuel supply, the Commission in its Fifth Supplemental Order in Cause No. U-83-26, found that the Company, then WWP, must absorb a portion of the costs of the project. The Commission decision was to limit WWP's recovery of the plant to the original estimate for which the original determination of prudence was made. The Commission found that "[t]he effect of this decision is that $80,555,706 of a total project cost of $89,299,000 will be used to calculate the allocation between jurisdictions." Id, p. 16. Finally, the Commission went on to identify the Washington portion of plant in that proceeding.

Subsequently, in Cause No. U-84-28, the Commission again found that the Company had not carried its burden of proof that all aspects of completing the Kettle Falls project were entirely prudent.

Q. **Did Avista's proposed adjustment for the Kettle Falls disallowance in the instant case do what the Commission ordered in Cause No. U-83-26?**

A. No. Mr. Falkner's adjustment shown in Column (g) of his Exhibit ___(DMF-2) fails to follow the Commission's order in three respects. First, Mr. Falkner calculates the balances of this Kettle Falls disallowance by using balances for the year 2006. This calculation results in the full Kettle Falls Plant being included in rate base on a per-books basis of the average of monthly averages (AMA) for 2004, but then removing the amortized disallowed piece on a 2006 basis -- which includes two extra years of amortization. As a result, based on the Company mismatched calculation, a portion of the disallowed plant is left in rate base.

I could accept the Company calculation of the disallowance if the Company had put the whole Kettle Falls plant into rate base using the projected 2006 levels, as there would be a matching of the rate base and the disallowance values. Of course under this scenario the net plant for Kettle Falls would also be reduced as a result of the two "extra" years of amortization that occur between historic 2004 and projected 2006.

The second problem with Mr. Falkner's calculation is that he does not follow the disallowance calculation contained in the Commission's Order in U-83-26, the Order in Cause No. U-84-28, or the Order and Stipulation in Docket No.UE-900093, Second Supplemental Order Accepting Stipulation, Appendix "A", Stipulation Resolving Contested Issues, Appendix A, Electric Results of Operation page 1, column (f), line 27. Specifically, Mr. Falkner takes the disallowance from the Order in U-83-26, as allocated to the state of Washington in that proceeding, and creates an amortization schedule of that hypothetical Washington jurisdictional balance as the starting point for his calculation. This violates the Order in Cause No. U-83-26, which specifically refers to the disallowance on Kettle Falls as being calculated on a total project basis before being allocated to Washington. U-83-26, Fifth Supplemental Order, p. 16.

Mr. Falkner's calculations would have resulted in an equitable outcome if the Washington jurisdiction's cost allocated cost responsibility for the facility had remained the same since Docket No. U-83-26. What makes this an issue is that Washington's allocated share of the total plant has grown from 60.02% in the 1983 time frame to 65.16% at the present time. If the Commission allows Mr. Falkner's calculation to stand, the Commission will be allowing a portion of the Kettle Falls plant in rates that has previously been determined by this Commission in two separate proceeding to be the responsibility of the Company and not to be borne by the ratepayers. To avoid this inequity, the Kettle Falls disallowance must be calculated as previously ordered by this Commission.

The third problem in Mr. Falkner's calculation is the addition of what the Company calls "accumulated depreciation." This amount is treated as a reduction in the Washington jurisdictional rate base disallowance by approximately $400,000 and an increase in the Washington jurisdictional depreciation expense by approximately $30,000. This $400,000 item derives from a Company bookkeeping entry in 1986 related to the disallowance as described in Avista's responses to PC Data Request Nos. 181 and 159. This journal entry was Avista's attempt to create a reserve for the ratemaking treatments ordered in Washington and Idaho consistent with generally accepted accounting principles as stated in Financial Accounting Standard No. 90. While Avista's bookkeeping may include an inconsistency, this Commission's treatment in the 1982 through 1991 period was consistent. Namely the plant should be limited to a certain level of recovery before allocation, and the Company should bear the remaining costs.

Q. Did you ask Avista to state which Commission Order authorized the treatment proposed by Mr. Falkner in this proceeding?

A. Yes. PC Data Request No. 9 asks for Commission orders that support Mr. Falkners position. The response refers to the U-83-26 Order, the stipulation in Docket No. UE-900093, and to an uncontested adjustment in consolidated Docket Nos. UE-991606 and UE-991607. While I am unfamiliar with the uncontested adjustment in the latter proceeding, his adjustment does not agree with those made in the other two cited, nor with the Commission's order in Cause No. U-84-28 where the issue was contested. In the U-84-28 Order, as in the U-83-26 Order, the Commission found that a portion of the total plant should be excluded from recovery from rate payers. While the issue is not discussed in the UE-900093 stipulation, it can be seen from the schedule attached to the stipulation that the Plant in Service disallowance is greater than the Plant in Service disallowance proposed by Avista in this proceeding. This would imply that the schedule utilized by Mr. Falkner here could not have been used in that proceeding since the plant in service number does not change from year to year in Mr. Falkner's schedule.

C. Adjustments Required by the "Matching Principle:" Coyote Springs, Column (D); Pro forma Transmission Project, Column (F); and Production Property adjustment, Column (G). Exhibit ___ (MRL – 2)

1. The "Matching Principle"

Q. Please describe the need for these three adjustments.

A Each of these adjustments is made in consideration of the "matching principle" consistently adhered to by the WUTC.

Q. Would you please explain the matching principle and why it is important?

A. The matching principle is the principle that requires maintaining the relationship between rate base and net operating income consistent with the period of time chosen. It is important to adhere to the matching principle to insure that a relationship between the net operating income and rate base can produce a rate of return that is meaningful. To adjust rate base to a period which is inconsistent with the calculation of net operating income creates a non-meaningful rate of return.

All cost of service components – revenues, investment, expenses and cost of capital – change over time. The "matching principle" dictates that all cost of service components should be considered and evaluated to a similar point in time. For instance, it would be inequitable to consider forecasted revenues – say, in the 2006 time frame – with 2004 actual expenses.

Q. With regard to production costs in this proceeding, how do the results presented by Avista and included in the settlement fail to meet the matching principle?

A. Avista's case presents a number of adjustments intended to proform the costs associated with Avista's power supply resources in the year 2006. While it is not typical to pro forma rate base items, sometimes significant events such as the addition of the second half of Coyote Springs 2, or the addition of significant transmission projects require the proforming of rate base. Absent these rate base adjustments the revenue, expense and rate base may all be matched historically, but they would not represent the relationship to be incurred in the future when rates are to be in effect.

This being said, one needs to be very careful in attempting to establish the proper relationship. A few facts demonstrate Avista's mismatching of cost of service components in the instant case:

- kWh sales are held at year 2004 level while the rate base for the second half of Coyote Springs 2 is at a 2005 level.
- The proforma rate base level for the transmission project doesn't represent any specific time period as Avista's calculations do not use actual tax or book accumulated depreciation from either 2005 or 2006.
- Pro forma operating costs of the second half of Coyote Springs, as with other Avista owned resources, are based on an estimate of 2006 costs.
- Purchased power contracts that served Avista in 2004 have been removed if the contract expired prior to 2006, and new purchased power contracts have been added.
- Finally, in developing the Aurora model, regional resources and regional loads -- excluding Avista's -- are based on 2006.

It is extremely important to note and emphasize that an analysis of Avista's net production plant, excluding the addition of the first and second halves of Coyote Springs, has shown a steady decline over the last two and a half years ending December 31, 2004. The decline in "net" production plant in service occurs when the growth in the accumulated depreciation, through continuing depreciation expenses, exceeds gross plant in service additions. Further, when one considers the increases in transmission plant in addition to production plant during this two and one-half year period there is no growth in the combined net production and transmission plant, again, other than those caused by additions of Coyote Springs.

Q. Please expand upon the resulting "mismatch" that occurs with the Company's pro forma results of operation presentation.

A. First, the Company's net production rate base (production plant in service less related accumulated depreciation and deferred taxes) is proformed to a higher level than existed in 2004 (due to the pro forma of the second half of Coyote Springs 2).

Second, based on the historical trends observed, the Company's pro forma net production rate base is higher than it is anticipated to be in 2005 due to the continued accumulation of depreciation and the continued growth in the accumulated deferred income taxes.

Finally, and importantly, the difference between the Company's proformed production rate base and anticipated production rate base will be even greater in 2006.

While Avista's production rate base is anticipated to continue to decline, the Company's normalized retail load – and attendant revenues -- is anticipated to grow. Avista's draft 2005 integrated resource plan projects that Avista's load is anticipated to grow by approximately 2.1 percent a year between 2005 and 2025. Technical Advisory Committee Draft, July 27, 2005, Section 1.6, p. 1-6. This anticipated growth is, of course, precisely why Avista is acquiring new resources such as the second half of Coyote Springs 2.

Proforming Coyote Springs to the 2005 level while leaving load at test year level creates two mismatches. First, as noted, the pro forma Coyote Springs net rate base is greater than the level expected to be incurred in the rate year of 2006. Second and more importantly, the total pro forma production rate base is higher than it will be in 2006 while the load it is intended to serve is 4% greater than the pro forma load included in the rate case. In summary, one type of "mismatch" occurs because Avista's actual 2006 production rate base is not expected to ever reach the level that the Company has proformed into its cost of service.   A second type of "mismatch" occurs because the load growth through the 2006 time period, the very growth that facilitated the decision to acquire additional Coyote Spring 2 capacity and energy, has not been proformed or adjusted for in Avista's adjusted results of operations calculation.

Q Has the Commission ever dealt with this mismatch in other electric proceedings?

A. Yes. Since at least 1980, in PSE's and its predecessor Puget Sound Power & Light's general rate cases, an adjustment to production rate base has always been made to match net pro forma production rate base to the load the pro forma production rate base is intended to serve. In this way, the pro forma rate base, which still tends to be higher than actual rate year net production plant, is matched to the load to be incurred during the rate year. The proformed projected rate year production rate base costs are then "brought back" (i.e., matched) to the test year load. This is accomplished through employment of a pro forma production rate base adjustment calculated by determining pro forma rate year production rate base on a per kWh basis utilizing the expected rate year load. This production rate base per kWh is then matched with the test year actual load to develop the same matched relationship between load and pro forma production rate base as determined for the rate year. Failure to make this traditional PSE adjustment while at the same time allowing a utility to proform the total cost of a new resource such as Coyote Springs 2 into rate base fails to meet the matching principle, and further, fails to comply with the Commission rule on pro forma adjustments, WAC 480-07-510(3)(b)(ii), which states: "'Pro forma adjustments' give effect for the test period to all known and measurable changes that are not offset by other factors. The filing must identify dollar values and underlying reasons for each proposed pro forma adjustment."

Q. Why does the Company adjustment fail to meet the Commission's definition of a pro forma adjustment?

A As I indicated above, Avista's one-sided approach to presenting pro forma adjustments results in a mismatch between load (and thus revenue) and the pro forma net production rate base. The Company's one-sided (i.e., considering costs only) pro forma method creates a mismatch by failing to identify and quantify other factors which offset the mechanical pro forma cost-side-only adjustment calculation proposed. This is particularly inequitable inasmuch as the new "proformed" resource is intended to serve the very growth in load that Avista fails to measure.

2. The Coyote Springs adjustment, Column (D)

Q. Please provide some background on the Coyote Springs plant.

Coyote Springs is a two-unit natural gas fueled 500+ megaWatt combined-cycle combustion turbine power plant located near Hermiston, Oregon. Portland General

Electric Company owns the first unit, and is the site manager and operator for both units. The second unit, Coyote Springs 2, was previously co-owned by Avista Utilities and Mirant (an independent power producer), but Avista purchased Mirant's interest (the "second half" of the second unit) in early 2005 and is now the sole owner of the second unit. Avista's initial share (the "first half") of Coyote Springs 2 was placed in rates in the last general rate case.

Q. Would you please describe the purpose of the adjustment for Coyote Springs in your Column (D)?

A. Yes. Subsequent to the test period, Avista completed its purchase of the second half of the Coyote Springs 2 generating facility from Mirant. I do not raise a prudence issue with regard to this purchase. Rather, I focus on the question of whether to proform this significant plant addition into Avista's results of operations for the purpose of this case, and if so, how. The first question is easy to answer. Because of the size of this investment, and the changes it will bring to Avista's results of operations, it would be impossible to set fair rates for the future without considering this investment.

This brings us to the second question, namely, how should the Commission proform the cost of the new plant into the pro forma results of operation? As discussed above a pro forma adjustment should be known and measurable and include all offsetting factors. Therefore, a two step process is appropriate.

First, the Commission should measure the costs of this new resource as it is going to be incurred during the rate year. Avista did not do this. Instead, Avista's adjustment to rate base pro formed Coyote Springs to the net balance expected to be incurred during 2005. In doing this, in addition to overstating the cost of this plant during the 2006 rate year, the Company may also have violated specific Internal Revenue Code rules governing the projection of net plant and attendant accumulated deferred income taxes (ADIT) balances included in rate base in rate proceedings. Specifically, IRC sections essentially mandate that ADIT must be matched, or measured consistently, with respect to projected plant in service balances. To alleviate potential violation of IRC rules and regulations, my adjustment measures the average accumulated deferred taxes during the 2006 rate year associated with the second half of Coyote Springs 2 rate base, (Note that 2006 is the rate year chosen by Avista in its filing. I have not opposed this selection).

The second step is to remove the mismatch between the production rate base which is pro formed to the rate year level and the pro forma level of retail load (and associated revenue) which has been pro formed to the 2004 normalized test year level. I will expand upon this step of adjustment below when I discuss the Production Property adjustment, Column (G), later in this section.

Q. What is the result of your proposed adjustment for Coyote Springs?

A. The impact of the first step described above is shown in my Column (D) in Exhibit ___ (MRL-2) as a reduction in rate base in the amount of $1,882,000 compared to Avista's adjustment.

3. Pro Forma Transmission Project, Column (F)

Q. Turning to your Pro forma Transmission Project, Column (F), adjustment, please explain why your adjustment differs from that proposed by Avista.

A. Similar to the adjustment for Coyote Springs 2, the Company's pro forma transmission plant adjustment results in total transmission rate base that is higher than per books net transmission plant during the 2004 test year. Further, for the specific transmission plant projects included within Avista's adjustment, the balance is higher than the expected net plant for each proformed facility included in rate base during either 2005 or 2006. Again, this occurs as a result of growth in the accumulated depreciation reserve as well as growth in the accumulated deferred income tax reserve for the specific additions. The Company's calculation of deferred taxes inappropriately and inconsistently compares one year of book depreciation to the second year of tax depreciation with no consideration given for the first year deferred taxes accumulated in 2005. Accordingly, I am proposing an adjustment that consistently and equitably measures the rate year level of these plant costs based on a 2006 average of monthly average balances for both accumulated depreciation and accumulated deferred taxes. I note that the accumulated deferred income tax reserve balances are done on an average basis to be in specific compliance with tax rules and laws.

Q. What is the result of your Pro forma Transmission Project adjustment?

A. As shown in Exhibit ___ (MRL-3) Column (F), I have reduced the pro forma rate base by $215,000 compared to Avista's initial filing.

4. Production Property adjustment, Column (G)

Q. Would you now discuss your adjustment shown in Column (G) of Exhibit ___ (MRL-2) and Exhibit ___(MRL-3), Production Property adjustment.

A. I introduced this subject above in the Coyote Springs, Column (D) section. This calculation is the second step I referred to there as being necessary to match the pro forma production rate base with the pro forma net operating income included in this case. Further, I have described how this adjustment is made in my discussion of the matching principle. As discussed above, I have matched the 2004 load to a proper 2004 proforma production rate base by looking at the relationship between the 2006 expected load and the 2006 pro forma rate base. The calculation takes the ratio of the expected 2006 load to the normalized 2004 load which results in a ratio of 1.042441. This ratio represents a 4.24% increase.

The next step is to divide the 2006 pro forma production rate base by this ratio to determine the proper pro forma production rate base that matches the normalized 2004 test year load This adjustment is consistent with standard Commission ratemaking practice over at least the last 25 years. *See, e.g.,* UE-011570, Settlement Stipulation, Exhibit A to the Settlement Stipulation, Exhibit A-4; U-89-2688-T, Third Supplemental Order, p. 41; Cause No. U-81-41, Second Supplemental Order, p. 5 (listed in uncontested adjustments to rate-base).

This treatment is also consistent with the concept that it is appropriate and necessary to pro forma production rate base for major additions of new plant such as Coyote Springs 2. As described previously, this second step of proforming production plant is made to “match” the relationship between sales/revenues and net operating income to production rate base, as the additions of new plants are specifically related to increases in load. To simply make a one-sided adjustment as Avista is doing in this proceeding by pro forming new plant such as Coyote Springs without analyzing all “offsetting” factors, is inconsistent with the Commission rules as identified above. By including the adjustment I propose, the Commission can properly match revenues to rate base for the test year.

It is most important to note that this adjustment does not penalize Avista as the per unit-cost of these net plant rate base costs is declining between new plant purchases (due to declining fixed costs being recovered over a growing level of sale units) .

Absent the various “matching” adjustments I propose, I recommend the Commission reconsider its practice of fully proforming production plant for new investments that are intended to serve new load. If my adjustment is not adopted, the Commission will overstate on a unit basis the fixed costs associated with production plant.

Q. Please describe how you calculated this adjustment.

A. I started with the total production rate base and depreciation expense included in Ms. Knox’s supporting workpapers. (Workpaper TLK-123) From that total I added or subtracted the various adjustments I made to the Company’s initial case in this proceeding, including those agreed to by the Company and reflected within the settlement. The resultant fixed production rate base total is then factored based on the 2 year cumulative growth rate of 4.244% (based on the predicted 2.1% annual grow in the draft IRP) expected to occur between the 2004 historic test year and the 2006 projected rate year. As shown in my Exhibit ___ (MRL-3) this adjustment decreases rate base by $15.2 million.

D. Cancelled Small Projects, Column (I), Exhibit ___ (MRL-2)

Q. Please describe your Cancelled Small Projects adjustment shown in Column (I) of Exhibit ___ (MRL-2) and Exhibit ___ (MRL-3). Why does it vary from the adjustment made by Avista in its initial filing?

A. This adjustment, as described by the Company, reflects the amortization of the estimated net abandoned costs associated with the cancelled small generation project at the Spokane Industrial Park. I note that the project at the Spokane Industrial Park is a breakout of the original project at Boulder Park. The original project at Boulder Park was planned for eight small generating units. Due to unanticipated emissions restrictions, Avista was allowed to install only six of the originally-ordered eight generators. Since Avista had already ordered eight generators Avista quickly planned to utilize another available project site at the Spokane Industrial Park. However, the project was ultimately cancelled after energy prices receded from their historic highs experienced in the 2000/2001 time frame. As a result, Avista is left with the two “uneconomic” and unused generators. As of the date of Avista’s filing in this case Avista had not yet disposed of the generators, and thus, the actual loss (if any) is currently unknown. I do not know whether Avista has disposed of these generators since the filing.

The adjustment proposed by Avista was to amortize the net loss anticipated to be incurred upon sale of the generators over a five year period, and to exclude the unamortized balance from rate base.

Q. Is Avista’s treatment consistent with prior Commission orders concerning abandoned projects?

A. No. In numerous orders from this Commission since 1982 the Commission decided that only the prudent portion of abandoned major project costs should be recovered, and further, that recovery of prudently incurred costs should be over a 10 year period without rate base inclusion. This type of treatment started with PacifiCorp's abandonment of Pebble Springs Nuclear project in its 1982 rate proceeding. Prior to that proceeding, cost's associated with small abandonments -- such as the one in this proceeding in many cases had simply been written off with no recovery.

Q. What is your position regarding the recovery of these small generation units?

A. I propose amortization over the standard 10 year period previously established by this commission. To my knowledge, the net loss or gain on this project is only an estimate, as the generators were unsold as of Avista's filing in this proceeding. To resolve this concern, it is my proposal that the difference between the estimated recovery level and actual sales price when the generators are sold be deferred, and then in the next general rate proceeding that this difference be amortized over the remaining portion of the ten year amortization. As a result, my proposal for rates in this proceeding is the same as included in the settlement, with an additional proposal to handle the actual salvage value recovered.

E. Boulder Park Disallowance, Column (E)

Q. Please summarize your understanding of the Boulder Park project.

A. Boulder Park is a project initiated by Avista in 2002 to install additional power capacity by locating multiple generators at the Boulder Park facility.

Q. Please explain your Boulder Park Disallowance adjustment shown in Column (E).

A. In this column I propose a disallowance for the Company's investment in the Boulder Park project. The adjustment in Column (E) is based on the disallowance calculation made by the Idaho Commission on this issue in October 2004 in Avista's general rate case in that state. *In the Matter of the Application of Avista Corporation For the Authority to Increase Its Rates and Charges for Electric and Natural Gas Service To Electric and Natural Gas Customers In the State of Idaho*, Case No. AVU-E-04-1; AVU-G—04-1, Order No. 29602, October 8, 2004, pp. 17-18. A copy of the relevant portion of the decision is attached as my Exhibit ___ (MRL-6).

The issue in this case is not whether Avista made the right choice in deciding to construct the Boulder Park facility, but rather, it is a question of whether Avista properly planned the construction of the facility and then properly managed that construction plan. After reviewing the evidence before it of delays and cost overruns, the Idaho Commission stated**:**

> We expect a utility such as Avista to have the expertise and experience to plan, construct and manage any project it undertakes at a reasonable cost. This project was planned as a "fast track" response to poor water and a volatile energy market. It was not completed on time and was 53% over budget. The Company must assume some responsibility for the excessive cost. Staff recommends a 10 % disallowance and identifies specific cost category overruns. We believe the Company should be held to a higher standard. Ratepayers will not be asked to pay for what we find to be a Company learning experience. Id., p. 18

My adjustment applies the same reasoning to the Boulder Park costs included in Avista's rate request in Washington.

Q. Please explain your adjustment calculation.

A. My calculation starts in the same place as the Idaho adjustment. On a system basis, I have removed all costs that were greater than 15% above the initial estimate. This results in a system plant in service disallowance of $7.62 million. After subtracting accumulated deferred income taxes and accumulated depreciation, my Washington allocated adjustment is a reduction to rate base of $4.4 million. My proposed adjustment is limited to the rate base as I do not propose to reduce the operating expense or depreciation expense. In this way the Company is allowed a return of the costs incurred but not a return on those costs.

F. Other Adjustments

Q. Are these adjustments identified in Exhibit ___ (MRL-2) the only adjustments you reviewed in this proceeding.

A. No, I spent some time reviewing several other adjustments related to the production costs or the ERM. In this proceeding I take no exception, at this time, to the following adjustments as proposed by Avista and included in the Settlement revenue requirement: Column (i) Settlement Exchange Power, Column (j) Hydro Relicensing Adjustment, Column (q) Eliminate Wa ERM Surcharge and Deferrals, Column (r) Nez Pierce Settlement Adjustment, Column (u) PGE Monetization, and Column (PF8) Sale of Skookumchuck.

IV. POWER SUPPLY ADJUSTMENTS:
ISSUES RELATED TO AVISTA'S PRO FORMA PF 1 AJDUSTMENT

A. Sources of Power Supply Adjustments

Q. Please explain the complexities of the Company's adjustment for Power Supply in Column (PF1).

A. Avista's adjustment for Power Supply displayed in Column PF1 contains numerous individual elements contained in four separate sources: (1) the Aurora model; (2) Mr. Johnson's testimony; (3) a $5.7 million adjustment in Mr. Falkner's workpapers; and (4) the "Mark to Market" adjustment.

Q Does your testimony cover all four sources of the Avista adjustment?

A. No. As noted, I have not directly analyzed the validity of the Aurora model itself, but have focused my investigation on reviewing the inputs and outputs of the model and upon Mr. Johnson's and other witnesses calculations. Therefore, I take no position on whether the model properly measures Avista's power costs. Other than a few minor exceptions, none of my adjustments to power supply are based upon a critique of the workings of the model. Therefore, any adjustment proposed by another party based on the workings of the model would not be expected to overlap with my adjustments. I will review other parties' testimony to verify this point in the next round of testimony.

Q. Please explain the first source for the Avista Power Supply Adjustment PF 1.

A. First, the Company ran the Aurora model utilizing 60 years of hydro information. The model contains, as I understand it, substantial information from the region concerning resource availability and loads for 2006. Each of the 60 years of hydro information is then run through the Aurora model so that Avista can normalize these costs over a range of possible outcomes. Other major inputs into the model are fuel costs, most notably projected gas costs. The Company runs the model based on regional incremental costs. From each of the runs the model determines the level and net power supply costs including secondary sales, secondary purchases, and fuel costs to be incurred. These results are then averaged over the 60 water years. Several of the inputs into the model represent the information specific to Avista's system. This information includes owned resources and contracts that are assumed to be run at variable levels or on a must-take basis. In Avista's case, most long term contracts are on a must-take basis.

Q. Please explain the second source.

A. The second source of the Avista pro forma adjustment is found in the testimony of Avista's witness Mr. Johnson, *see* Exhibit No. ___ (WGJ-3). The testimony presents several individual pro forma adjustments where the Company takes the output from the model and prices various portions of the net production costs at some pro forma price. Many contracts are added or subtracted and prices changed.

A summary of these first two sources is shown on a system basis in Mr. Johnson's Exhibit No. ___ (WGJ-2). A few of the adjustments shown in this exhibit stem directly from the first source, namely, Mr. Kalich's results of the model run shown in his Exhibit No. ___(CGK-3). The Kalich adjustments included in Mr. Johnsons Exhibit No. ___ (WGJ-2) are the amount for short term market purchases on line 1, the fuel costs shown on lines 32, 34, and 37-42, and the short term market sales on line 59. The remainders of the adjustments included in his exhibit are, for the most part, the result of Mr. Johnson utilizing Mr. Kalich's results from the model and combining that with information obtained from other sources. Most of these adjustments are briefly discussed in Mr. Johnson's Exhibit No. ___ (WGJ-3) where he identifies approximately 50 separate pro forma adjustments.

Q Please explain the third source of the Avista Power Supply Adjustment.

A. The third source of this adjustment is found only in the workpapers of Mr. Falkner for adjustment PF1. The workpapers include a column titled "Transmission Adjustment" which is the summary of adjustments from the third source. This summary shows an adjustment to pre-tax system net operating income of $5.7 million, which is over half of the total pro forma system power supply adjustment.

This transmission adjustment is unsupported by the testimony of Mr. Falkner or either of the two power supply witnesses Messrs Johnson and Kalich. While Mr. Falkner's testimony indicates that the power supply adjustment comes from Mr. Johnson, Mr. Johnson provides no testimony, exhibits or workpapers concerning this third source. There are no detailed workpapers supporting these calculations or explaining any of the 14 sub-component adjustments included in this Company-proposed adjustment -- other than page PF1-5 of Falkner's workpapers which simply listed each item with a couple of footnotes at the bottom of the page. Some additional information was provided by Avista regarding the adjustment within the last month, but the material was merely descriptive in nature and did not provide calculations supporting the original adjustment.

Q. Please explain the fourth source of the Avista power supply adjustment.

A. The fourth source of the adjustment is also shown on Mr. Falkner's workpapers, at worksheet PF1-2, as shown in the sixth column entitled "remove Washington Mark to Market," an adjustment that increases expenses by $349,000 as shown. Again no witness refers to this adjustment; however Mr. Falkner's workpapers do contain a sheet showing the annual balance of a sub account of FERC account 557 titled "Washington Mark to Market." If this account does contain the net Mark to Market for 2004 it would be appropriate to remove such costs.

Q. Would you now go through your Exhibit ___ (MRL-4) and explain what it presents.

A. Yes. Exhibit ___ (MRL-4) lays out the original power supply adjustment PF1 included in Avista's initial filing, and further sets forth my adjustments that are consistent with the proposed settlement. The first four columns represent the calculation of the system adjustment prior to allocation to Washington. The $10.007 million decrease to net operating income before federal income taxes agrees with the system adjustment included in Mr. Falkner's workpaper PF1-2. The next twelve columns represent my understanding as to the content of adjustments shown in Attachment A of the proposed settlement. When testimony and supporting information as to these settlement adjustments is available I will modify this exhibit, if necessary.

The fifth, sixth, and seventh columns, entitled "Oasis Revenues," "Borderline Revenues" and "Production Factor adjustment," when combined, are consistent with the Pro Forma Power Supply adjustment shown on the second line of adjustments in settlement Attachment A. I do not take a position on the Borderline wheeling number, pending a review of any supporting information which may be filed. With respect to the Oasis Revenues it would appear that the revenue for this item included in the settlement appears low. I discuss this item later. Finally, I have no information on the Production Factor adjustment and therefore take no position on it. Accordingly in my next exhibit I have removed this adjustment in calculating my pro forma power supply adjustment.

The eighth column is consistent with the adjustment shown in settlement Attachment A for Coyote Springs 2 fuel that increases revenue requirement by $3.651 million. I did not review the natural gas cost of $7.25 /dth proposed in this adjustment. I understand this settlement adjustment also modifies the hydro years from Avista's proposed 60 years to a 50 year study. I take no position on this issue.

The ninth column, "Transportation Double Cost Removal," reflects the apparent removal of transportation costs for CS2 that were included in both Mr. Kalich's model run and on line 38 of Mr. Johnson's Exhibit ___ (WGJ-2). The proposed adjustment appears to remove the amount included within the model. This adjustment appears entirely proper as the same cost should be represented only once in the operating statement.

The tenth column, Kettle Falls Fuel Conversion Factor, is consistent with the settlement Attachment A adjustment of that title. I do not have the specifics on how this settlement adjustment is calculated, but note that my own calculations of Kettle Falls fuel costs do not agree with this total. I will discuss this discrepancy later in my testimony

The next adjustment in my Exhibit ___ (MRL-4) entitled "Power Supply - Colstrip Maintenance" is consistent with the system energy costs associated with the settlement adjustment entitled "Power Supply-Colstrip Maintenance." The adjustment appears to come from a modification to how scheduled maintenance for

Colstrip is run through the Aurora model. This adjustment is beyond the scope of my examination and I take no position at this time on its accuracy.

The next five columns are my additional adjustments associated with the items identified in footnote 3 to Attachments A of the settlement. While I have no workpapers or descriptions of the settlement adjustment entitled "Power Supply-Additional Misc. Adjustments," these five adjustments which I sponsor herein produce exactly the same revenue requirement impact as the settlement Attachment A adjustment.

B. Colstrip Fuel

Q. Would you please describe your adjustment for Colstrip Fuel?

A. Yes. In response to a data request related to Mr. Johnson's workpapers, Avista supplied an inventory analysis of Colstrip coal for an extended period ending in May of 2005. Public Counsel Data Request No. 188. When I reviewed this information and compared it to Avista's calculation of fuel expense I found that Avista's initial filing understated the cost of coal relative to that currently being experienced. Thus, using the MWhs from Mr. Kalich's Exhibit ___(CGK-3) and the information from the data request response regarding the current cost of coal and the generation per ton of coal, I determined that the fuel cost for Colstrip was understated by $199,000.

C. Miscellaneous Purchased Power Contracts

Q Would you please explain your adjustments represented in the column entitled "Miscellaneous purchased power contracts?"

A. Yes. The purchased power adjustments are presented in the first 23 lines of Mr. Johnson's Exhibit ___(WGJ-2) The scope of my investigation did not include the amount for short term market purchases shown on line 1.

To explain the various adjustments that I propose, it is crucial to understand how Avista arrived at its pro forma adjustments. In some instances Avista has proformed an item to known quantities and rates. Examples of these are contracts listed in Exhibit No. ___(WGJ-2), lines 9-12 which are for specific quantities at specific prices. This is also the case for the WNP-3 contract, as the quantities and prices are known. Some of the other items are based on normalized quantities multiplied times a specific price. Many of the small power contracts fit into this category. Still other contracts have variable quantities that are normalized by Mr. Kalich, for which the pricing is not done on a per-kWh basis but the on the basis of actual costs. These include contracts for the Mid Columbia hydroelectric resources such as Rocky Reach.

Q. Please explain what adjustments you made to these contracts and why.

A. To start with, I made adjustments to the pro forma level of costs to Rocky Reach and Wells. (I make a similar adjustment for Wanapum which I address in a later section). In each of these pro forma calculations, Mr. Johnson utilized budgeted information from the relevant Public Utility District (PUD) to determine the pro forma level of expense. In my past audits of PSE and Avista I have discovered that these budgets are estimates used for billing the subsequent year's costs. But as the year progresses the actual costs tend to vary from the budgeted levels, and in a majority of cases, result in excess amounts being billed. These excess billed amounts are then refunded to the customers after the year is completed. Some of the PUDs may have better records of projecting costs than others, but in all cases, the budgeted amounts simply do not meet the pro forma definition included in Commission rules of being known and measurable. My calculations of the pro forma level removes the budgeted amounts, corrects the test year amount where appropriate to include the refunds applicable to the test year, and further removes the prior period true ups.

Q. What are the other adjustments included in the Miscellaneous Purchased Power adjustment?

A. I made adjustments for the Black Creek contract and for the two parts of the Grant County contracts (the Displacement and Grant Revenue Credit).

Q. Please explain the Black Creek adjustment.

A. This new contract calls for kWhs delivered to be priced at a specified index price for a certain month less a specific credit for services rendered by Avista. A review of the workpapers revealed that the Company's initial filing had not been updated to the index rates input into the model. My modification simply updates these costs to reflect the rates being used in the model.

Q. Please explain the Grant Displacement adjustment.

A. This adjustment results from my discovery that when Avista modeled the Grant Displacement contract it used an earlier estimate of the kWhs to be received through this contract than was included in the final contract. Avista's response to PC Data Request No. 182 verifies this inadvertent error. The earlier estimate included some 3000 fewer MWhs annually than what had been included in the earlier estimate. In order to determine the value of these additional MWhs, as the Company did in its response to PC Data Request No. 182, I compared the fixed price of the contract to the average power price included in the model during the three months affected. The resulting adjustment decreases system cost by $43,000.

Q. Please explain the Grant Revenue Credit adjustment.

A. Avista is assigned a portion the value of a specific level of secondary sales from the Priest Rapids project. The benefit of these sales is the difference between the secondary market rate and Grant County PUD's actual cost of producing this power. As with the Black Creek adjustment, Avista failed to update the sales rate included in this revenue credit to those included in the Aurora model. Updating for current sales prices and using the actual cost of producing power resulted in an adjustment increasing the benefits derived from this contract on a system basis by $20,000 above the level included in the initial filing.

Q. Does this conclude your discussion of miscellaneous power purchase contracts?

A. Yes, except that I address a similar issue below regarding the Wanapum contract.

D. Transmission Coyote Adjustment

Q. Please explain the Transmission Coyote adjustment you propose.

A. The Company estimated costs associated with the fixed costs of gas transportation in Mr. Johnson's Exhibit ___(WGJ-2), line 38. As mentioned earlier, this "fixed cost" portion of the adjustment was redundant to the gas costs included with the Aurora model. However, as also previously stated, Avista has now removed the portion of costs within the model. *See*, Settlement Attachment A, CS 2 Transportation adjustment. With respect to Mr. Johnson's gas transportation cost adjustment, the

Company originally estimated the tariff rates to be applied to these transportation services over the three pipelines used to move gas to Coyote Springs. My proposed modification to Avista's adjustment is to pro forma these purchases at the known and measurable prices available using the current Canadian exchange rate. Some of the rates I used were higher than proposed by Avista while some were lower. My resulting adjustment is $240,000 lower than originally proposed by Avista.

E. Rathdrum Storage Adjustment

Q. Explain the Rathdrum Storage adjustment.

A. During 2004 Avista had a contract for gas storage at a cost of $40,000 a month. That contract expired in early 2005. This adjustment removes the non-recurring test year level of expense for this item.

F. BPA Garrison Wheeling Adjustment

Q. Please explain your adjustment for BPA Garrison Wheeling.

A. In Avista's initial filing the Company made an adjustment for these transmission wheeling costs based on an assumption that these cost-based wheeling rates would escalate at a rate of 2% a year for three years (Avista Response to PC Data Request No. 113). The Company provided no evidence that BPA is intending to increase these cost-based wheeling rates. Accordingly, absent BPA actually requesting a transmission rate increase, it is improper to pro forma a 6% increase for this item.

V. POWER SUPPLY ADJUSTMENTS: INCREMENTAL

Q. Please now refer to your Exhibit ___ (MRL-5). Would you explain what this Exhibit shows?

A. Yes. This exhibit represents my additional adjustments to power supply costs that are incremental to those that I have just explained in Section IV above. The first column represents what I believe to be the revised PF1 included within the settlement agreement on a Washington basis. The next nine columns represent eight additional adjustments I am sponsoring with respect to the Power supply adjustment (PF 1), as well as the removal of the Production factor adjustment which at this point in time I cannot support. Each of the adjustments discussed in the nine columns are "total system" adjustments. These nine adjustments are totaled in the column entitled "System Total Additional PC Pro forma." The next column shows the Washington intrastate share of these adjustments utilizing the 65.16% Washington jurisdictional energy allocation factor. The second to last column entitled "Total PC PF1 Adjustment Pre ICNU Model adjustments" includes the total of my pro forma power supply adjustments. I note that my recommendations do not include any Aurora model adjustments expected to be proposed by ICNU in this proceeding. Until I have an opportunity to review ICNU's testimony I do not take a position on any ICNU power supply adjustments that would be incremental to those I am sponsoring.

A. Normalization Issues

Q. Does the Company use a consistent method when they normalize costs based upon an average of several years' historical data?

A. No. The Company appears to vary the normalizing period based on the information available. In many cases Avista tries to explain why different averages are used. I would note that unless I propose an adjustment that challenges Avista's normalization process, I have accepted Avista's rationale to use the varying normalization periods. However, I have concerns about Avista's normalization approach that affect a number of my adjustments.

Q Please demonstrate what you mean by varying normalization periods used by Avista.

A. The major power supply variable is the running of the hydro normalization. In the case of hydro availability, the Company argues that all historical data available should be considered, and thus proposes that the entire 60 years of available data should be included in the hydro normalization process. In many other cases, however, Avista rejects the concept of using all available data including the examples of the varying techniques listed below.

On the small hydro projects one contract is normalized based on the most recent three years. The resulting average is lower than all but one of the other 14 years available. Another small hydro contract project is averaged over five years when an additional ten years are available, with eight of those ten years yielding greater output than the average used by Avista. A third hydro projects output is developed by considering a five year average, but with six of the additional ten years of available data showing outputs that are above the five-year average; A fourth hydro contract is normalized over four years with five of the eight additional years showing higher output. The Hydro tech contract is also averaged over five years, but in this case, the additional five years of additional data appear to be similar to the five-year average employed by Avista. In each of these noted cases the Company states that the old information is not consistent with how the contract is currently performing. Noting that Avista has no control over the maintenance of these contracts I do not reject the reason proposed by Avista at this time.

Another example is the conversion factor for tons of Colstrip coal per MWh generated. Here Avista utilizes a five year average, but employs data from the period 1997-2001 instead of the most recent five years available. In another area, for wheeling costs related to market sales and purchases, Avista also used a five year average even though the secondary sales and purchases were based on the 60 year model. I will expand upon this issue later in my testimony.

For transmission revenues Avista uses different averages for each subcomponent. Specifically, Borderline Wheeling revenues are based on a five year average, revenues from PP&L Dry Gulch are based on a three year average, while Oasis transmission revenues appear to be based on some extrapolation of the first half of 2005 and are set at a level below any of the last five years. I am uncertain as to what period of years was used to normalize broker fees, but in a data request response Avista indicated it utilized a five-year average. Broker fees, like transmission costs, are related to market sales and purchases and will be discussed later in my testimony.

Q. Is it inappropriate to exclude certain years from the normalization process?

A. An argument can be made either way. To look at the data and attempt to use only those years that appear to be normal, results in an adjustment that removes abnormal events. Removal of the abnormal event that may not reoccur for several years -- or ever -- assures that the costs are not over or understated. Further, the next "abnormal" event may go in the opposite direction than the previous "abnormal" event, thus suggesting that the best way to "normalize" an item is to remove all "abnormal" events.

On the other hand, it can be argued that while individual abnormal events are non-recurring, over a period of time it is reasonable to expect some type or level of abnormal events to occur. For example, this year a BPA line may go down, and five years from now another line goes down or a power plant may go offline for an extended period of time. It can be argued that some historical abnormalities should be considered and measured in developing an "average" or "normalized" base line – realizing that it is reasonable to consider some level of individually-determined "abnormal" event to, in fact, be ongoing or "normal." In my view it is reasonable to eliminate events determined to be abnormal, but it is important that such removals should be done consistently. In this proceeding I do not believe Avista is being consistent in its removal of abnormal events or conditions.

B. Kettle Falls Fuel Adjustment

Q. Your first adjustment column in Exhibit ___ (MRL-5) is entitled "Kettle Falls Fuel." Would you please explain this adjustment and describe how it relates to the Kettle Falls Fuel adjustment in your Exhibit ___ (MRL-4)?

A. Yes. The initial workpapers of Mr. Johnson indicated that he was proposing to proform Kettle Falls wood fuel supply at $17.67 per ton. Utilizing a conversion factor of 1.4 tons/MWh resulted in a Company-proposed price of $24.74 per MWh. Item 32 in Mr. Johnson's Exhibit ___(WGJ-3) p.3, indicates that this fuel cost was calculated using the Aurora model's kWh projection and the projected price of fuel. In fact, a review of the fuel cost at Kettle Falls used in Mr. Johnson's Exhibit __

(WGJ-2) reveals that he did not reprice the fuel cost included in Mr. Kalich's model run. Reviewing these documents and dividing the pro forma level of costs by the MWh reveals that the pro forma price used was approximately $22.78. I issued data requests asking for actual purchases and inventory reconciliations. I also requested the contracts under which Avista was making these fuel purchases.

A review of the contract pricing that currently exists does not give a clear picture of the average price Avista pays for its wood supply. Each of the contracts vary quite substantially from the other contracts. In some case the only cost is transportation. The total prices under these contracts appear to consistently range over $20 a ton. As a result, review of the actual purchases, which includes the actual mix incurred, provides the best information concerning this fuel cost. A review of the inventory over the last couple of years does not appear to display the same type of cyclical movements as observed in the inventory values for the Colstrip coal inventory which I also reviewed. As a result, I think that the most reasonable price to use for establishing rates in this proceeding is the current value of Avista's inventory -- assuming there are no extraordinary adjustments made in the last month that might temporarily affect the inventory price.

Q. What is the Kettle Falls fuel price you used?

A. Based on Avista's response to PC Data Request No. 216, I have used a price of $17.085 per ton. This may be the same price used in the settlement between Staff and Avista but I cannot verify that at this time. The next step is to convert the noted price per ton of wood to a price per MWh. In PC Data Request No. 186, I asked for the tons burned and the kWh produced from those burns for the period 2002-2004.

The response revealed that during the test year the ratio was 1.434 tons per MWh– which was the basis of Mr. Johnson's originally proposed rate of 1.4 tons/MWh. However, I noted that in 2003 the ratio was 4.472 tons/MWh while the rate in 2002 was a little higher at 1.633 tons/MWh. However, my review of MWhs generated in 2002 revealed that only 70% of the normal level was produced in that year. As the efficiency of the wood burn appears to be dependent upon the wetness as well as the quality of the wood product, such a year could not be considered normal for calculating this ratio. Thus, for my calculation I used an average of the 2003 and 2004 ratios. My proposed two-year average ratio, which is higher than the actual test period of 1.434 and also higher than the ratio proposed by Mr. Johnson of 1.4 tons/MWh, produces a higher cost per MWh than that proposed by the Company. As a result, my pro forma level of expense for Kettle Falls Fuel is $727,000 higher than that originally proposed by the Company.

Q. How does this compare to the adjustment for Kettle Falls fuel contained in the Settlement?

A. The adjustment proposed in the Settlement includes an increase of $1,163,000 in Kettle Falls fuel costs over that proposed by Avista within its original filing, as well as, an adjustment that is $437,000 higher than that which I am proposing herein. I may address this settlement adjustment in further detail once the specifics of how the adjustment was developed have been provided.

Q How does the normalization issue impact the adjustment you are proposing here for Kettle Falls Fuel?

A. In this case it appears Avista has moved to an average that is inconsistent with what happens in a normal year. They appear to be proposing to use a year that did not have normal burns at the Kettle Falls plant.

C. Oasis Revenues

Q. Your next adjustment relates to Oasis revenues. Please describe the problem with Avista's original pro forma adjustment for this item.

A. As indicated previously, Avista did not supply testimony or work papers supporting this adjustment. In response to my inquiries to the Company and the Staff, Staff requested Avista to supply support for Oasis Revenue. In a fax sent to Staff on July 25, and then relayed to Public Counsel, Avista supplied a description of why many of the transmission adjustments were made, but provided no work papers supporting the calculation. The Oasis Revenues adjustment was one such item for which calculations supporting the adjustment have never been provided. The description provided simply states that "[r]evenue for Oasis has been revised down from $5,475,000 to $1,500,000 based on a projected lower level of third party transmission usage and revenues anticipated in the rate period primarily due to BPA transmission additions." Again, no work paper supporting Avista's original calculation was submitted.

Subsequently, Avista supplied additional information concerning the Oasis Revenue. The test year Oasis Revenue was $5.4 million, while the five year average (2000-2004) is $4.4 million. The three year average (2002-2004) is $4.2 million, with calendar year 2000 experiencing the lowest Oasis revenues with $2.4 million.

Q. How do you propose to pro forma the Oasis Revenue?

A. I have excluded the two highest historical years from the average as being abnormal. I propose to include $3.2 million of Oasis Revenues by considering a three-year average of remaining "normal" years. My adjustment combines the settlement Oasis Revenue of $860,000 from Exhibit ___ (MRL-4) and the additional PC adjustment of $831,000 in Exhibit ___ (MRL-5). When I receive supporting work papers for the Oasis Revenue settlement adjustments I will correct these two amounts if necessary but the total of the two is my adjustment to the initial filing.

D. Broker's Fees and Wheeling Expense

Q. Could you now explain the adjustments for Broker's Fees and Wheeling Expense for system sales and purchases?

A. Yes. Avista's cost of service is normalized based upon 60 years of hydro. As a result of this normalization process, secondary purchases and sales were reduced substantially. However, for these two items (brokers fees and wheeling for market sales and purchases) Avista apparently decided that test year levels were too low. Accordingly, for wheeling cost Avista used a five year average. With respect to brokers' fees the Company simply indicated that its adjustment represented an the estimated amount.

Q. What review did you do of these two expense items?

A. With respect to brokerage fees, I reviewed the invoices expensed by Avista during the test year. Other than a $12,000 fixed charge, brokerage fees vary based upon the amounts in the larger transactions, or on the number of transactions for smaller transactions.

With respect to the wheeling charges, I did a comparison of wheeling charges to the combination of secondary sales and secondary purchases. My analysis revealed that there is a direct relationship between these two items.

The adjustments proposed by Avista not only appeared to be in error, but more importantly, were going in the wrong direction. Accordingly, I have proposed adjustments which tie wheeling charges to the level of market purchases and sales. In discussions with Company personnel, Avista argued that the model fails to individually measure all secondary market transactions, but instead only measures net transactions. Company personnel referred to transactions that were Avista's attempt to reduce anticipated costs, essentially attempting to lock in lower costs. However, Avista's argument fails to recognize that if there are additional sales or purchase transactions, each of those transactions is intended to reduce the cost being incurred by Avista. Thus, when an additional sale is above the level included within Avista's pro forma case is made, such sale is made with the intent of increasing the net benefit from such secondary sales. When the Company makes those additional sales, it is Avista's responsibility to make sure that the transactions result in a reduction in net expense -- not an increase.

Further, it is imperative that all variable costs – including the wheeling charges and brokerage fees -- need to be included in such determination. On a secondary sales transaction, net expense includes the incremental power costs incurred by Avista at the time of the sale plus other direct avoidable costs associated with the sale. Those direct costs include broker fees and Avista's share of the transmission expenses. With respect to off-system market purchases, the same can be said. Specifically, the evaluation of these purchase transactions should include both brokerage fees and transmission expenses.

Q. Are you trying to say that every additional sale or purchase transaction will produce a net benefit greater than the brokerage fee and transmission costs?

A. No. Avista makes numerous secondary power transactions. Some result in a "win" while some will result in a loss as the Company is trying, in many cases, to protect itself from anticipated movements in the market. Sometimes the Company undertakes transactions that offset each other, or in some instances, transactions are undertaken for short term hedging purposes. Not every one of these transactions can be expected to be a benefit, but if in the long run these transactions do not cover the direct variable cost of engaging in such transactions, the Commission should have a serious concern about Avista's sales and purchases activities.

To summarize, the extra transactions that Avista is concerned about should produce a net benefit to the Company beyond what is included within its pro forma power supply adjustment in this case. If it is appropriate to include these additional costs, then it is also appropriate and equitable to include the net benefit from undertaking the transaction that the extra costs are intended to generate. In this case Avista only wants to add the "expense" of engaging in secondary sales and purchases, but wants to keep the benefits derived from such activities.

Q. Please describe your calculations of each of these two adjustments.

A. First, my adjustment for transmission expense related to market sales and purchases uses a five year weighted average cost of transporting the sold and purchased kWh. After calculating this level of expense I increased this cost by approximately 18% for the Bonneville rate case. My adjustment to test year actual recorded costs was a reduction of $214,000. Comparing my adjustment to test year recorded actual operating results to Avista's $80,000 increase results in a reduction to the Company's filed or proformed case of $294,000 on a system basis.

Second, for my adjustment for Brokerage Fees I subtracted the portion of test year brokerage fee costs that were fixed costs to determine amount of variable test year brokerage fee costs. I then calculated that total sales and purchases dollars were decreased by 57% in the Company's power supply adjustment, and thus calculated a 57% decrease in the variable brokerage fee costs, resulting in a $30,000 reduction to test year recorded brokerage fees. Comparing this to the Company's adjustment of $13,000, my total adjustment to the Company's initial case is a reduction in cost of $43,000.

Q. Do you have any other concerns about using a five year average for these items?

A. Yes. Review of the sales and purchases over the last five years reveals that the years 2002-2004 all had similar experience in sales and purchases, but that the year 2001 had more than double the test year level of sales and purchases, and further, the year 2000 had nearly 5 times as many sales and purchases as did the test period. As previously noted, these periods during the energy crisis have been removed for purposes of normalizing many other portions of the case. Accordingly, to be consistent, it would be totally inappropriate to include these direct costs associated with those two abnormal sales and purchase years when developing pro forma brokers' fee levels.

E. Wanapum Contract

Q. The next adjustment in your Exhibit ___ (MRL-5) deals with the Wanapum contract. Please explain this adjustment.

A. I introduced this issue earlier when talking about the other purchased power adjustments included in my Exhibit ___ (MRL-4). The problem here is that the Company, while purporting to rely upon the budget of a third party PUD, in fact relies on an unsupported one-page projection of multi-year costs. I would note and emphasize that the supporting sheet offered is entitled “Unofficial Wanapum Power Cast Forecast” and does not appear to be a part of the 2005 budget proper. It is a forecast of costs for the project through the year 2013. Nowhere in the 100 page budget document, however, is there a single page which supports the “unofficial” forecasts for 2006 and beyond. It is simply not a proper known and measurable proforma adjustment to rely on Grant County PUD’s “unofficial” and thus far totally unsupported forecast.

On the basis of this, Avista increased its overall O & M costs by over 40% for this project in this two year period. A substantial portion of that cost increase is related to the increasing debt costs associated with capital projects carried on by Grant County PUD last year. However, the increase also includes a heretofore unexplained estimated 24.6% increase in Grant County’s O & M expenditures.

My proposal is to remove those portions of the Grant County PUD budget that appear to be speculative, and thus are not known and measurable. Thus, while I believe the new debt costs represent a legitimate and understandable change at Grant County associated with new financings, the escalation of the PUD’s unexplained O & M expenditures should not be included in the pro forma. Thus, rather than the

$1,012,000 (40%) adjustment proposed by Avista, I propose an increase for Wanapum on a system basis of $643,000. This still represents a 25.5% increase in fixed test year costs.

It would be reasonable to assume that the O & M expenditures at these various hydro projects would increase over time, even though the year-to-year comparisons do not always result in evenly-spread increases. The combination of the current low rate of inflation combined with some level of productivity may explain why year-to-year comparisons do not always show an increase each and every year. However, even if these increases do exist, they represent only trends in costs over time, and are not known and measurable events. Further, as I discussed with respect to my Production Property adjustment, these fixed costs in the 2006 period are for resources that will serve greater loads than existed in the test year. Thus, if they are looked at on a cost-per-kWh unit basis, increases in total fixed costs can be expected to be offset in whole or in part by such fixed cost being spread over a greater number of kWh sales units.

F. Garrison-Burke Transmission

Q. The next adjustment refers to Garrison Burke transmission. Please explain this adjustment.

A. The Garrison-Burke transmission expense, otherwise known as the Montana transfer, consists of payments made on an irregular basis to Northwestern Energy, previously known as Montana Power. According to the Company, this payment is for the transmission of excess power generated at the Colstrip plant in Montana. The Company proposed a normalization adjustment for this item based on a five-year average of payments made (See Avista WP 95). As I discussed earlier, Avista uses multiple time periods to normalize certain costs or revenues.

This item again highlights the dangers in utilizing the varying normalization period for each account. On the revenue side Avista argued that 2001 was abnormal because of these problems and did not believe that including this "high year" experience in the normalization process was fair. But with regard to the expense side Avista wants to use all five years of available data in the average. In the instant case, 2004 was the lowest of the last five years by over 26% from the 2000 level (for which the Company has not supplied the invoices requested by Public Counsel), and 31% less than calendar year 2002, the next lowest year.

Q. What is your proposal for the normalization for Garrison-Burke sub account?

A To be consistent with the approach to the Oasis Revenues adjustment, I excluded the abnormal number from 2001. I also excluded the 2000 numbers as I was unable to obtain the invoices to verify these amounts. I note that the schedule of the 2000 amounts supplied to me as a substitute revealed that in October of 2000 there may have been some other abnormal firm amounts included. As a result, my proposal increases these costs by $43,000 on a system basis as compared to the Company adjustment of $82,000, or a reduction of $39,000 from the Company's initially filed case.

G. Rathdrum Lease

Q. Please explain the Rathdrum lease adjustment.

A. During the last 10 years Avista has incurred a lease expense for the Rathdrum facility, a combustion turbine power plant in Rathdrum, Idaho. While this lease meets the requirements for capitalization under generally accepted accounting principles, the lease was held by an unconsolidated subsidiary. For ratemaking purposes the lease payments have been treated as an operating expense. Interestingly, those payments to date have only covered the interest cost of the lease, while the total cost of the plant (i.e., the "principal" portion) remains to be amortized for ratemaking purposes.

In this case the Company initially pointed out that the lease was entering a new stage in 2005, and at the expiration of the current lease agreement Avista would have to make lease payments which included both the interest and the principal portion of the financial lease. Based on this fact the Company prepared an amortization schedule for the remaining balance of $56,260,000 using 173 monthly payments and an annual interest rate of 8.3629%. Avista's pro forma monthly lease payment, based on this schedule, was $560,721, resulting in an annual increase in costs of over $2 Million.

Q. Do you agree with this calculation?

A. No. When I reviewed the responses to my data requests concerning this adjustment, it was revealed that the anticipated interest for this lease, including administrative charges and equity markups, was only 6.85%. Using this interest rate, results in a monthly lease payment of only $512,646, a reduction in annual cost of $577,000 on a system basis from that proposed by Avista. This is the adjustment I propose in this proceeding.

Q. Do you have other concerns about the Rathdrum lease?

A Yes, it appears that the Rathdrum lease agreement may not presently exist, and based on a response to my data request, it apparently never will. At Avista's May 2005 Board of Directors meeting, the board decided to terminate the Rathdrum lease and finance the plant with debt financing. The data submitted to the board made a comparison of the cost of a synthetic lease to cost to Avista for outright ownership. Basically the presentation showed that the Company would be able to reduce long term costs through ownership because the administrative charges and equity markups included in the imbedded lease rates will no longer apply.

Q. Is the termination of the lease in the rate payers' best interest?

A. That is difficult to tell. If the benefits of reducing this debt costs are in fact passed through to the rate payers it would appear that this would benefit the rate payers in the long run. But, there is the problem, as testified to by Mr. Hill, in that the capital structure being proposed by Public Counsel, and by the capital structure of the settling parties, is hypothetical. The hypothetical capital structure is the one that applies to Avista Utilities. If this lower cost debt is added to Avista Utilities it will lower the overall cost of capital for the utility even further. There is no proposal in this case to reflect the anticipated but as yet unissued debt financing. It would be imprudent for Avista Utilities to change its method of financing Rathdrum if, as a result, there is a long term negative impact to the ratepayers.

Q. What are the short term impacts on revenue requirement of changes from an operating lease to a rate based and depreciable asset?

A. In general this would have the impact of increasing rates in the short run but not in the long term. Operating leases levelize the combination of interest expense and principle repayment cost of a facility over its entire useful life. Conversely, when a facility is rate based and depreciated, the return plus depreciation on the facility in the early years of service will be much higher than that experienced through levelization of costs vis-à-vis an operating lease. This occurs basically because depreciation expense in the early years of commercial operation under the rate base scenario exceed the "principal" payment buried within the early years of the levelized lease payment.

Q. **What occurs if, in between rate cases, Avista changes the form of financing for a leased piece of property?**

A. Avista would normally have to absorb the additional amortization of the property not included in rate base.

Q. Do you have a proposal regarding the Rathdrum lease in the instant case?

With respect to the termination of the Rathdrum lease it is uncertain that ratepayers will actually benefit from this action. But assuming in a future proceeding Avista can demonstrate that it is in the ratepayers' best interest to traditionally finance and rate base a facility previously leased, I believe it would be appropriate to undertake steps at this time that would protect Avista from being harmed by the move to capitalize the currently leased plant. In order to protect Avista, the Commission could simply provide them an accounting order allowing them to amortize the plant using a present value schedule consistent with the principle portion of my lease payment schedule. Under this scenario, if the change in financing results in a true and quantifiable reduction in debt cost as claimed by Avista, then the Company would be able to reap the benefits between now and the next case of these reduced debt costs.

H. Transmission Expenses

Q. Your next Power Supply adjustment addresses transmission expenses. Would you please explain this adjustment?

A. Yes. These transmission items are part of the Pro Forma Transmission adjustment PF 1 discussed earlier (the "third source"). Avista initially supplied no testimony or work papers in support of either the eight expense adjustments or six revenue adjustments that it proposes. In response to a request for backup, Avista supplied a multi-page document. However, with respect to all of the expense adjustments and five of the six revenue adjustments, Avista supplied only one paragraph in total describing why each adjustment was made. Apparently many of the expenses come from two actions taken by Avista -- namely, to join wesTTrans, and to rejoin the Western Electric Coordinating Counsel. Avista's actions to join these two organizations should theoretically yield benefits, or there would be no reason to join. At this point I have not taken exception to the $150,000 of additional costs for these memberships proposed by Avista. My concern, however, derives from one line descriptions of two adjustments – namely, a $48,000 amount for Colstrip O&M 500KV line, and a second amount of $116,000 to Electric Scheduling and Accounting services.

With respect to the Colstrip increase, Avista has increased costs by over 18% based on an unsubstantiated budget from Northwestern. This is an improper pro forma calculation as the cost changes are not known and measurable, and accordingly, should be rejected.

With respect to the other item, the description refers to transfers of accounting responsibility. Changes in how an item is accounted should not change the total cost.

In summary, without complete workpapers and supporting documentation, neither of these two adjustments should be adopted. Accordingly, my adjustment removes system costs of $164,000. I will revise this adjustment, if necessary, after I receive and review data responses asking for support for these two Company adjustments.

I. Production Factor Adustment

Q. Your Exhibit ___ (MRL-5) also has a column entitled "Remove Production Factor adjustment." What is this column for?

A Included in my Exhibit ___ (MRL-4) is a Production Factor adjustment. As I am not familiar with the Company's calculation or the purpose of this adjustment, I do not want to include it in Public Counsel's total cost of service recommendation at this time, and therefore I have reversed it on Exhibit ___ (MRL-5).

VI. AVISTA'S ENERGY RECOVERY MECHANISM

A. Summary and History

Q. Please summarize your testimony with regard to the Avista Energy Recovery Mechanism (ERM).

A. My testimony will cover the following topics:

- the history of the ERM;
- a description of how the ERM currently operates ;

- a review of the Commission's prior guidance concerning power cost adjustment (PCA) mechanisms and recommendations on what a PCA should provide;
- the changes proposed by Avista to the ERM and my recommendations regarding those changes;
- a comparison of the Avista ERM to a properly structured PCA ;
- a proposal to restructure the Avista ERM into a properly designed PCA.

Q. Please briefly review the history of the ERM.

Avista has had a power cost adjustment mechanism in the state of Idaho since approximately 1990, and has periodically sought a similar mechanism in Washington without success. The Company requested a PCA in its 1999 general rate case, Docket UE-991606. The Commission denied the request, finding that the Company proposal was inappropriate in that docket.

In the period from 1999 to 2002, Avista's excess power cost were the subject of inquiry in several docketed proceedings. The Commission approved establishment of a deferral account. After initial projections that the deferral account would be reduced to zero by 2003 with no change in rates, the account balance increased substantially and in October 2001 a temporary 25% surcharge was established for recovery of the deferred costs pending resolution of Avista's 2001 general rate case. *See WUTC v. Avista Corporation*, Docket No. UE-011595, Fifth Supplemental Order¶¶ 9-20 (reciting history of Avista deferred power cost issues). In June 2002, the Commission approved a settlement of the 2001 rate case which included the establishment of a new Energy Recovery Mechanism (ERM). Id., ¶¶

34-40. The ERM was not designed as a traditional PCA but was a simpler mechanism.

B. A Description of the Avista ERM

Q. Please provide a description of Avista's ERM as it currently operates.

A. Essentially, the ERM is a device that allows Avista to recover for fluctuations of power costs outside of a certain range. The ERM compares actual to what are termed "authorized" power costs, costs which are reflected in a specified group of accounts. The ERM adjusts this comparison for over-recovery or under-recovery of power costs due to load changes from the so-called authorized load. This is accomplished by means of the "retail revenue credit adjustment." Under- or over-recovered costs are accounted for in the ERM deferral account. Avista collects a surcharge from its customers to pay down the deferral account.

Although not stated as such, the ERM is in fact a unit cost mechanism. That is, it determines the deferral level by comparing costs on a KWh basis rather than on a nominal amount level. The ERM starts by separating power costs into two separate buckets: (1) net power supply expense; and (2) other production costs.

The first bucket, net power supply expense, includes FERC Accounts 555 Purchased Power, 501 Thermal Fuel, 547 Combined-cyle Turbine (CT) fuel, and 447 Sale for Resale. The net fuel expense from the sale of gas not included in Account 547 is added to this total. Potlatch purchased power is not included. The second bucket includes all other costs, including return and taxes on rate base, that were allocated as production costs in the cost of service study in the last proceeding.

Q. Where is the first bucket or group of accounts directly identified?

A. In the original ERM order and the reports filed with the Commission.

Q. Please identify what costs are included in the second bucket.

A. As stated above, the second bucket includes all costs which were allocated in the cost of service model in the prior rate case using a production allocator. Those items include:

1) All 500 account amounts that were not included in the power supply costs. This includes all the production related operations and maintenance (O&M) excluding fuel.
2) All production related taxes.
3) Production related insurance.
4) Return on net production plant including federal income tax, this includes plant in service, accumulated depreciation, deferred taxes, and numerous regulatory assets.
5) Portions of all costs that were allocated on an overhead allocation factor including returns and taxes on net rate base. This item made up over 7% of the total costs.
6) Provision for uncollectibles and Commission fees.

Q. Please explain where this second bucket of costs is included within the ERM.

A. Unlike PSE's PCA where the fixed costs are specifically identified in the PCA documents, in the ERM this second bucket of costs (the fixed costs) is included within the Washington retail revenue credit adjustment.

Q. Please provide an example of how the ERM works.

A. As noted, the ERM starts off by comparing actual costs to what it terms “authorized” power supply costs (the “first bucket”). This is the group of specific accounts stated in the original ERM order. Then, using the retail revenue credit adjustment, the ERM adjusts this comparison for over-or under-recovery of its power costs due to load changes from the so-called authorized load. A hypothetical example would be as follows:

Results that establish the base for the ERM

Authorized or rate case test year load (kWh)	10,000,000
Authorized power supply expense (Variable costs 1st Bucket)	$200,000
Other production cost from test year (Fixed costs 2nd bucket)	$200,000
Total unit cost aka the retail revenue credit factor ($400,000 divided by 10,000,000 kWh)	4 cents per kWh

ERM year 1

Actual Load (kWh)	11,000,000
Actual power supply costs (variable cost)	$220,000
Actual less authorized power costs ($220,000-$200,000)	$20,000
Retail revenue adjustment -(1,000,000* 4 cents)	- $40,000
Net Power Cost Increase or decrease (-)	- $20,000

In this case, total pass through costs equal other production of $200,000 plus $220,000 of actual variable costs for a total of $420,000 or (~3.82 cents per kWh) compared to the authorized 4 cents per kWh times actual load of 11,000,000 kWh or $440,000. Therefore despite the variable power cost being $20,000 higher than authorized, the adjusted actual totals are a credit of $20,000 available to go through the sharing formula.

ERM year 2

Actual Load (kWh)	8,000,000
Actual power supply costs (variable cost)	$140,000
Actual less authorized power costs ($140,000-$200,000)	- $60,000
Retail revenue adjustment -(-2,000,000* 4 cents)	$80,000
Net Power Cost Increase or decrease (-)	$20,000

In this case total pass through costs equal other production of $200,000 plus $140,000 of variable costs for a total of $340,000 or (4.25 cents per kWh) compared to the authorized 4 cents per kWh times actual load of 8,000,000 kWh or $320,000. Therefore despite the variable power cost being $60,000 lower than authorized, the adjusted actual totals are a debit of $20,000 available to go through the sharing formula.

Thus, through the ERM mechanism the variable costs are adjusted to actual but the remaining production costs from the second bucket are left at the test year level. In Avista's current ERM, as a baseline, the total production costs were measured at $.03208 per kWh.

Q. After measuring the net power increase or decrease and after applying the retail revenue credit, what is the next step in the ERM process?

A. The next step is to take the net power difference and apply the various sharing bands. Under the ERM, the first band is $9 million annually which is 100% the responsibility of the Company and its shareholders. This is referred to as the "dead band." After this dead band, costs are shared 90/10, i.e., Avista is responsible for only 10% of the remaining difference. Any portion of the costs or credits that are the responsibility of ratepayers are tracked in the ERM deferral account and recovered or refunded through the ERM surcharge (Schedule 93).

C. Prior Commission Guidance Regarding Power Cost Adjustment Mechanisms.

Q. What three broad policy goals has the Commission stated with respect to PCA mechanisms?

A. The Commission has stated that (1) a power cost adjustment clause should be linked to factors that are weather related; (2) "a power cost adjustment should be a short-run accounting procedure that reflects the short-run cost changes affected by unusual weather," whereas the prudency of long run resources is the proper subject for a general rate case; and (3) where a PCA is established, ratepayers should receive the benefit of a cost of capital reduction. *See, e.g.,WUTC v. Puget Sound Power & Light*, Docket Nos. U-89-2688-T, U-89-2955-P, Third Supplemental Order pp. 13-15; *WUTC v. Washington Water Power*, Docket No. U - 89-2363-P, First Supplemental Order, p. 8.

Q. What other guidance has this Commission previously provided regarding the structure of a PCA?

A. In several decisions over the years, the Commission has enunciated guidelines for designing an acceptable PCA. A PCA should be an improvement over the status quo. Surcharges should be understandable to the rate payers. The Commission has expressed concern that a PCA should not mechanically measure cost changes in certain accounts without considering offsetting expense reductions, for example, where increased purchased power expenses related to major plant shutdowns resulted in cost reductions not measured by the mechanism. A PCA should not provide incentives to do the wrong things, such as discouraging the Company from conservation when it is the cheapest resource.

Q. Please describe what these statements imply about a proper PCA.

A. These statements establish six important criteria for PCAs.

First, the impact of a PCA needs to be logical and understandable to the ratepayer in its application. In other words, ratepayers need to be able to understand why a surcharge or credit is being applied to their bills. Customers need to be able to see the drought or other uncontrollable event as connected with the increased rates that result from the PCA. Long deferral cycles that leave ratepayers without a natural understanding of why the surcharge is necessary fail to meet this standard. Rate increases and decreases associated with the PCA should coincide to a reasonable degree with the events that cause the deferrals.

Second, a PCA mechanism should allow deferrals only in situations where total costs of providing service have increased. Thus, if the mechanism fails to measure some portion of the cost of power to the system, the mechanism may unfairly defer costs when costs are not actually increasing in aggregate.

Third, the cost increases should be for items related to weather (stream flow) or other items that are truly out of the control of the Company. It is worth noting that, in a certain sense, nothing is fully out of control of the Company. While it cannot control weather or other external events, a Company has the ability to anticipate and respond to situations and limit the impact of various supposedly uncontrollable events. Some of these controls include the shape of the utility's portfolio, the fuel procurement plans and risk management. By responding properly in many situations a utility can reduce the impacts identified by Avista witness Mr. Peterson. *See, e.g.*, Exhibit. ___ (RRP-1T), p. 33-35. Many utilities have successfully managed their businesses for decades without relying on PCAs or other risk shifting mechanisms. Ratemaking has always taken into account the fact that weather related factors experience variability. Of the three major investor-owned electric utilities in Washington, only PSE at this time has a comprehensive PCA mechanism.

Fourth, ratepayers need to be specifically compensated for the transfer of risk from the stockholder to the ratepayer. This is best accomplished by a reduction in the cost of capital. Absent a reduction in the cost of capital, a substantial portion of the risk should be left with the utility rather than transferring it to the rate payers.

Fifth, the mechanism needs to keep the utility "in the game." That is the utility needs to be at risk at all times so that deferrals to ratepayers are accompanied at all times with some level of impact on the stockholders. In this way, the utility's incentive to minimize costs remains at all cost levels.

Sixth, the mechanism should not be designed so as to defer costs that are long range in nature. Increases related to general inflation for single items and new resources are more appropriately dealt with in a general rate case. For this reason, the Commission has stated that cost increases associated with new power contracts should be excluded from PCA mechanisms. Docket No. U-89-2688-T, Third Supplemental Order, p. 14. As noted above, the Commission has stated that a PCA should be a short run accounting procedure to measure short run cost changes. Long range costs such as new contracts need to be reviewed in the context of changes in the complete cost of providing service. For example, as noted earlier, Avista's production rate base has shown a steady decline over the last 3 years if the impacts of the major plant purchase of the two halves of Coyote Springs 2 are removed.

D. Avista's ERM and the Commission Standards

Q. Does Avista's ERM as it is currently constructed satisfy the criteria described above?

A. In a few respects yes, but generally it fails. It was designed more as a short-term relief mechanism during the power crisis, not as a permanent element of rates. Below I examine the ERM in light of each of the six criteria just discussed.

Q. Please discuss the first criterion, whether the ERM is logical and understandable to the ratepayer.

A. As it is currently operated the ERM is not logical and understandable to the ratepayer. It is not the details of the calculations that need to be simple. Avista, the Commission, Public Counsel and other parties can deal with a mechanism that is complex so long as it is fair. What the ratepayer needs to see, however, are rate changes occurring when it is evident that there is an uncontrollable event causing a need to change rates. In Avista's case, the ERM has had a surcharge for several years but the deferral balance remains high. Payment of the surcharge continues but no longer coincides directly with the events that caused the deferrals.

Q. Regarding the second criterion, does the ERM measure the full cost of providing power, thereby insuring that short term cost increases represent real cost changes for Avista in the total cost of delivering power to the system?

A. The ERM does not fully meet the need to look at total costs of providing power. While the retail revenue credit gets close to this goal, it currently does not include all costs associated with delivering power to the system. Most notably absent are costs related to transmission associated with generation and transmission revenue. By contrast, PSE's current PCA mechanism includes portions of transmission costs, as have prior PSE mechanisms such as the Energy Cost Adjustment Clause (ECAC) employed in the 1980s. Nor are all variable costs included in the variable portion of Avista's ERM. This can be corrected fairly simply. The mechanisms are in place. Avista maintains accounts that track these missing expenses which can simply be added to the ERM.

A further problem is that, if a major resource is terminated (e.g. sold) or out of service for a long period, there will be increases in net power costs that flow into the mechanism. The problem is that terminated or out of service plant also creates cost decreases that are not presently included within the measurements of the ERM.

Q. With respect to the third criterion, do the ERM deferrals reflect only power cost changes that are not under control of the Company?

While the ERM does include cost changes that are out of control of the Company, it also includes items that are very much under the control of the Company, such as new power contracts. As noted above, new contracts are not properly included because they are not unanticipated by the Company and like newly owned resources they have the potential to change the relationships between revenue, expenses and rate base. The Company has significant ability to control the timing and terms of these contracts, which are typically of a longer term duration, the type of resource properly addressed in a general rate case.

Q. What about the fourth criterion? Are the ratepayers compensated for the transfer of risk to them from shareholders?

A. As currently designed the ERM does not represent a major transfer of risk. The large dead-band leaves Avista responsible for a substantial amount of risk. Absent the ERM mechanism, Avista might well have sought emergency rate increases to deal with extraordinary and persistent conditions that resulted in increased costs. Avista in fact did so during the energy crisis. Thus the risk transfer for ratepayers is minimal. Avista's proposal in this case changes this relationship.

Q. **Does the ERM meet your fifth criterion? Does it keep the utility exposed to some risk, i.e., "in the game", so as to maintain an incentive to minimize costs?**

A. Generally yes. Once power costs exceed the $9 million deadband, all remaining costs are shared on a 90/10 basis. This 10% outside sharing band has a sufficient impact to maintain the Company's incentive to manage costs. This criterion is a separate consideration from the size of the dead-band, or the design of other sharing bands used to moderate the transfer of risk discussed above.

Q. Applying the sixth criterion, are increased costs that belong in a general rate case proceeding excluded from the ERM?

A. No. The mechanism as currently designed allows all changes in the purchased power and fuel accounts to flow through the mechanism. For example, new contracts, changes in contract pricing, and fuel costs that are independent of a fluctuating market (such as coal) are all cost elements that are included within the mechanism but that should properly be reviewed in a general rate case. The problem is that these cost increases are included in the ERM calculation, while at the same time the mechanism holds production rate base at the previous rate case level despite its steady trend downward, thus passing on unfairly inflated cost increases to ratepayers. In order to be consistent with the Commission's guidance that a PCA should be a short run accounting procedure for short run cost changes, no long term cost increase items should be passed through the ERM.

E. Avista's Proposed Changes to the ERM

Q. What changes has Avista proposed in this proceeding?

A. There are at least two proposed changes. As stated in the testimony of Mr. Peterson, Avista is proposing to eliminate the $9 million dead band. The second change is not expressly discussed in Avista's direct testimony and can only be discovered by reviewing the workpapers of Ms. Knox. To identify this change requires referring to to the testimony of Mr. Johnson. Mr. Johnson testifies that there will be no change in how the retail revenue adjustment is calculated, and indicates that the retail credit factor will be $33.99 per MWh.[1] Exhibit ___ (WGJ-1T), p. 12, line 7. Mr. Johnson points to Ms. Knox's cost of service study as the source of this number. This number can be found in Ms. Knox' Exhibit. ___(TLK-3), page 2, line 27, Column (f) expressed in cents per kWh. This number is calculated by taking the total production cost on this exhibit, page 2, line 22, column (f), and dividing it by the total retail load in her model of 5,154,025,000 kWh. Finally, one need to go to her work papers supporting the $175,176,296 total production cost shown on line 22. Her work paper TLK 121 has a breakdown of these costs as follows:

267	Operating and Maintenance Expenses	139	139,893,000
268	Direct Admin and General Expenses	140	1,847,877
269	Depreciation and Amortization Expense	141	17,314,000
270	Other Income Related Items	142	674,000
271	Taxes Other Than Income	143	3,446,000
272	Income Taxes	1275+1276	10,279,076
273	Uncollectibles and Commission Fees	1315 x sum 267~272,274~275	6,922,381
274	Return on Rate Base	1232 x 1304	35,855,961
275	Operating Revenue Other Than Rates	147	(41,056,000)
276	Net Production Cost		175,176,296

[1] This is the retail revenue credit adjustment that is applied to all changes in retail load. In my introductory example above describing how the ERM operates it is the 4 cents per kWh ($40 per MWh).

Q. Are these the same costs as included in establishing the current retail revenue credit factor of $0.03208 in the last general rate case proceeding?

A. No. In response to PC Data Request No. 2, I received the printout of the cost of service calculations that supported that number. The total Net Production costs in that proceeding were $160,680,259, and the calculation of that total included all of the items listed above plus two additional amounts, allocated common expenses and allocated common return on rate base. Further, the income tax, and uncollectibles and Commission fees line amounts are dependent on other items in the calculation. Based on that last study Avista has proposed a reduction of just over 7% in this factor. There is no mention of the change in any testimony, nor support for why the change is appropriate.

Q. What is the impact of reducing the retail revenue credit factor?

A. Assuming the load escalates as projected by Avista, reducing the factor decreases the retail revenue credit thus increasing an under-recovery and lessening an over-recovery. In other words, it gives more dollars to the Avista shareholders.

Q. What do you think about the two changes Avista has proposed to the ERM?

A. With respect to the modification of the retail revenue credit factor, I believe the adjustment is wholly unwarranted. Further, as no Company witness addressed this issue the Commission should reject it and order Avista to recalculate the retail revenue credit factor to include, at a minimum, all costs included in the original calculation. My full recommendation concerning the establishment of the retail revenue credit factor is that all net costs related to the delivery of Avista's resources into Avista system should be included in this number. I will discuss this later in my testimony. Specifically, the removal of some of the costs related to production from the retail revenue credit calculation violates the second criteria I discussed above, namely that the mechanism needs to measure all costs related to production. To do otherwise cam result in deferrals when total costs are not increasing.

Q. What is your opinion regarding Avista's proposal to eliminate the dead band?

A. The dead band elimination is a substantial shift in risks between the ratepayer and the Company and its shareholders. When such a shift occurs the Commission has asked for specific benefits to be identified for this risk shift. PSE currently has a comprehensive PCA with significant risk left with the shareholder and at this point in time PacifiCorp does not have any deferral mechanism. I do think it can be said that investors anticipate that electric utilities in Washington will bear a significant level of risk. Further, modification of Avista's risk without remedying the other shortcomings of the ERM mechanism would be premature. While I would agree that the level of the deadband may need to be modified, that should only occur in conjunction with a comprehensive revision of the mechanism. I present my proposal on this issue later in my testimony.

Q. You referred to the PSE mechanism. What items in the PSE mechanism keep PSE more at risk than the proposals Avista makes?

A. The major one is PSE's sharing bands. PSE has a dead band of $20 million and a second band of $20 million with 50/50 sharing. The dead band alone leaves PSE's stockholders at risk for a change in return on equity of approximately 1.2%. When the exposure in the second band is added, the return on equity would be affected by approximately 1.8%.

I did a comparison of these PSE impacts with Avista's proposal to eliminate the dead band and to set all shareholder sharing at 10 %. I first determined, based on comparable total rate base, that a similar sized dead band for Avista would be $6.25 million. Using this $6.25 million range and 90/10 sharing, the impact on equity return if Avista incurred power costs in the range of $6.25 million would be 0.13%, as compared with the 1.2 % impact to PSE cited above. In a two band comparison the impact on Avista's equity return would be only 0.26%. Even using the settlement dead band of $3 million, the risk to the shareholders is still only 0.7% return on equity in the first band and 0.83% over the two bands. By comparison the $9 million dead-band results in an approximate 1.84 % impact on equity rate of return.

In addition to the size of the bands, PSE is not allowed to include rate increases in its numerous contracts into the actual power costs in the PCA. Instead, these contracts are recalculated at the pro forma rate case level as a maximum. In the calculation of purchased power costs, normal and general rate case items such as increased contract rates are subtracted. In PSE's case this can represent a sizable reduction in allowed costs, for which PSE is responsible.

PSE is also not allowed to include new long term purchased power contracts in the actual costs for deferral at their total cost, unless by including the required new transmission, the contract is below the existing embedded costs.

The PSE mechanism also has an adjustment to provide for the circumstance when one or more of the Colstrip plants experiences a major outage. In this way the Company is at risk for costs related to these major outages. PSE is still permitted to ask for recovery of the costs associated with such an outage in a separate proceeding, but this does remove the automatic calculation within the PCA which may over-compensate the Company and unfairly shift costs to ratepayers.

Finally, the PSE mechanism includes all transmission costs related to bringing power into PSE's system. These types of transmission costs, if included in Avista's mechanism, would increase the retail revenue credit factor. An increase in this factor in a growing utility would reduce the level of positive deferrals, a benefit to ratepayers. This is not a penalty but is rather an attempt to make sure that the increased costs are truly increased costs in total.

Q. Based on these items above do you see any need to change the sharing band mechanism of Avista's ERM at this time?

A. I believe that changes in the band sharing should be addressed only as part of a comprehensive reform of the whole ERM mechanism, which would include changes to remove the inclusion of general rate case items such as new contracts and existing contract increases. My recommendations are set out in the next section.

Q. Do you recommend that the Commission consider piecemeal changes to the ERM sharing bands or other components?

A. In my recommendations below I propose changes to the ERM that could easily be adopted by the end of the year, including changes to the sharing bands. If the Commission decides not to direct that these changes be made to establish a new PCA for Avista, the ERM mechanism is up for review in 2006. Until such time as a comprehensive reform is adopted to be in compliance with the guidance of this Commission and the criteria I have identified above, the existing ERM should remain in place. Changing the dead band or the sharing bands now in isolation, absent a comprehensive change of the mechanism simply shifts an unwarranted level of risk to ratepayers with no compensating benefit.

F. Recommendations: Transforming Avista's ERM to a PCA

Q. Would you now present your recommendations to make the ERM into a proper PCA?

A. Yes. In order to make the ERM a proper PCA there are several adjustments that can be made. In summary, they are:

- the inclusion of all appropriate power costs;
- modification of the variable cost category (bucket) to remove "general rate case" type items and add other items that vary directly with short term events;
- revise the sharing bands, including the dead band.

Q. Please discuss the power cost issue.

The first concern is that the mechanism needs to include all costs of power. To determine what costs these are one has to look at the decision process in determining what resource should be purchased. In this process the cost of generation is coupled with the cost of moving that generation into the service territory, together with the cost of connecting the resource to the regional transmission system so as to accommodate sales of excess power when the market warrants. It is this total cost that should be included. It should be noted that I am not attempting here to measure transmission costs that are incurred to move power around Avista's distribution system.

In Avista's case this means including (1) wheeling expenses from BPA and other utilities, (2)wheeling revenues, and (3) transmission rate base and associated expenses including depreciation, O&M, insurance and property taxes.

For this last item, transmission rate base, the numbers may be a little harder to define, but not as difficult as it may seem at first. The transmission rate base I refer to is part of Avista total transmission rate base. I considered three options to derive these numbers. The first option would be to identify the transmission used to set transmission rates at FERC. A second option is to use transmission plant that Avista identified in the efforts to establish an RTO or other transmission entity. The third option, and the most straightforward, is to include all 230 kV and above transmission lines. These amounts are directly identified in Avista's annual report to the Commission including the O and M expense. At this time, I recommend this third approach to calculate transmission rate base. In addition, the pro forma adjustment for the transmission project included in the case would need to be added to the test year level.

Q. What would be the second change regarding variable costs?

A. The two buckets of costs need to be redefined. The variable costs as currently included in the mechanism need to be modified as described below to remove general rate case items. Further, wheeling expense and transmission revenue should be included in the variable costs. Another item that should be considered variable is brokerage fees.

Q. What are your proposed changes to the variable costs currently included in the ERM?

A. As described above with respect to PSE's PCA, general rate case items need to be removed from the calculation of actual costs. My recommendation at this time is that contracts be limited depending on the type. Contracts such as Black Creek that are market priced, and small PURPA contracts that are priced at tariff should be allowed to flow through at the actual cost. Contracts that had cost rates like the Grant County Displacement contracts should be capped at the rates per kWh pro formed into general rates. The old Mid Columbia contracts that are priced based on costs, these contracts should be capped at the level of total pro forma costs included in the pro forma results.

In addition, a restriction on the inclusion of new contracts into the deferral calculation needs to be made. When a new longer term contract is entered into, the cost of that new contract including additional transmission should be capped as it is represented in the deferral calculation at the lower of the embedded cost found in this rate proceeding or the average market rate during the time of its operation.

Q. Do you have any recommendations with respect to major plant outages?

A. Yes. Avista has three base load fuel fired plants. They are Kettle Falls, Colstrip 3 and 4, and Coyote Springs 2. It is my recommendation that if any of these plants fails to meet an availability factor of 70% during a deferral year, that a credit adjustment be made to the actual power costs to remove a portion of the fixed costs associated with the plant included in this rate proceeding. That percentage would be determined by taking the actual availability of the plant during the test year and dividing it by the availability factor used in this proceeding. This resulting percentage would be subtracted from 100%.

For example, assume Kettle Falls operated at a 45% availability factor in 2006. And further assume that in this case it had been proformed at an 80% availability factor. Finally, assume that the fixed costs included in the retail revenue credit calculation were $30,000,000. The credit to operating expense would be calculated as follows:

Actual availability	45%
Proformed availability	80%
Ratio of actual to proformed (45/80)	56.25%
Credit percentage (100-56.25)	33.75%
Pro formed fixed costs	$30,000,000
Credit to variable cost (30,000,000 times 33.75%)	10,125,000

Q. Is it your proposal that Avista would have to absorb this entire cost?

A. Not entirely. I propose that, in order to have the credit or a portion of it reversed, Avista would have to file a petition to demonstrate two things. First, the Company would have to demonstrate that the outage was not something under the control of Avista. Second, the Company would have to demonstrate the actual level of fixed costs during the year. To the extent the fixed costs are higher than what was left in the deferral up to the level from the last rate proceeding, they should be allowed to reverse the credit calculated. Basically the point of this clause is not to disallow prudently incurred costs but to limit the deferrals to the actual costs incurred. A simple example shows the logic of this: if the Colstrip plants operate less, there is less need for the scrubbers to operate, and considerable savings are possible in scrubber operation and maintenance expense. This savings should partially offset the replacement power costs, and the method I have proposed achieves this.

Q. Would you now move to a discussion on how the sharing bands should be established?

A. Yes. As discussed above the sharing bands should accomplish two goals. The first goal is to avoid a substantial risk transfer from the shareholder to the ratepayer. This goal needs to be considered in combination with consideration of hardship on the utility, specifically with its ability to continue to pay its dividend and grow equity value. The second goal is to keep Avista at risk to some degree through all levels of deferrals.

It is my recommendation, when coupled with the other restrictions, that a sharing mechanism should attempt to hold Avista earnings above its dividend payout ratio if that ratio is reasonable. I believe Avista's dividend policy is reasonable. Thus I believe that a mechanism that over a reasonable range of divergence limited Avista impact on equity return below 2% to be reasonable. This would result in a return above 7% and allow for a small amount of other portions of sharing to be absorbed by Avista and still achieve this goal.

My proposal would be to establish a three tier band. The first would be dead band of $6 million. A second band with 50/50 sharing would also be set at $6 million. The third band, above $12 million, should be set to keep Avista at some degree of risk in an attempt to give Avista the incentive to minimize cost. A 10 percent Company share would definitely achieve this goal.

As a result of this three band structure, the impact on Avista's rate of return on equity through these first two bands would be less than the 2% I identified as reasonable.

Q. Do you have any specific recommendations regarding the deferral account and the surcharge?

A. Yes. First, however, let me provide some background. There are problems with the deferral account and the surcharge as they currently operate. The deferral account is currently $105 million. The amount collected by the Schedule 93 surcharge is approximately $27 million per year. While a detailed history is beyond the scope of this testimony, the salient point is that surcharge recoveries are not making significant progress in retiring the deferral. The situation is akin to ratepayers making minimum credit card payments on a revolving account that keeps growing. One undesirable aspect of this is that the principle of generational equity is not served. As more time passes, ratepayers are increasingly paying for power costs incurred to serve an earlier generation of customers. A second and related issue is the disconnect between the surcharges experienced by today's customer and the events causing the surcharge.

One solution to this problem is to accelerate the pay down rate of the deferral account by increasing the current surcharge level. Care must be taken with this approach, however, to avoid causing rate shock to customers. I would not support increasing the surcharge in conjunction with a significant increase in the customer's basic rates. However, the Commission could consider this solution in an environment where any base rate increase is modest and the overall impact of base rate and surcharge increases to small consumers avoids creating rate shock. In this case, I believe the revenue levels recommended by Public Counsel, with incremental changes proposed by ICNU, if adopted, provide a good opportunity to address the deferral account problem.

In that context, I would propose that the deferral balance at the end of 2005 be set aside and amortized by an increase to the current surcharge. If adopted as part of Public Counsel's overall rate recommendation, an increase to the surcharge of 10% would be reasonable. The amortization period would be approximately 4 years. I will address this issue further once I have had an opportunity to review the August 26 testimony of other parties.

Q. What would you recommend with respect to new deferral amounts which would occur prospectively?

A. If the Commission adopts the Public Counsel proposal for a new Avista PCA in this case, that PCA would operate separately, and could potentially create its own surcharge or refund if sharing bands are exceeded. Newly created deferral balances should run their own course. Thus, at the end of 2006 if there is deferral that exceeds as a reasonable trigger mechanism, then Avista should file for an additional surcharge or credit to retire the new balance. $10 million would represent a reasonable trigger level. I do not support having a new surcharge or credit passed through in a rate change each year no matter the size of the deferral. Such a surcharge (or credit) should coincide to the extent possible with an unusual event that the ratepayers can understand and when the deferrals are sizable enough to have meaning. This is comparable to the trigger mechanism contained in the PSE PCA mechanism. There may be other reasonable approaches to setting a trigger mechanism. The key point is that some type of trigger be established as opposed to automatic annual rate changes.

Q. Does this conclude your testimony?

A. Yes.