Exhibit No. T-___ (APB-1T)
Docket No. UE-030751
Witness: Alan P. Buckley

BEFORE THE WASHINGTON STATE
UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. AVISTA CORPORATION, d/b/a AVISTA UTILITIES, Respondent.	DOCKET NO. UE-030751

TESTIMONY OF

ALAN P. BUCKLEY

STAFF OF THE
WASHINGTON UTILITIES AND
TRANSPORTATION COMMISSION

RE: AVISTA ENERGY RECOVERY MECHANISM

August 25, 2003

I. INTRODUCTION

Q. Please state your name and business address.

A. Alan P. Buckley, 1300 South Evergreen Park Drive Southwest, P.O. Box 47250, Olympia, Washington 98504. My e-mail address is abuckley@wutc.wa.gov.

Q. By whom are you employed and in what capacity?

A. I am employed by the Washington Utilities and Transportation Commission as a Senior Policy Strategist. Among other duties, I am responsible for analyzing rate and power supply issues as they pertain to the investor-owned utilities under the jurisdiction of this commission.

Q. What are your education and experience qualifications?

A. I received a B.S. degree in Petroleum Engineering with Honors from the University of Texas at Austin in 1981. In 1987, I received a Masters of Business Administration degree in Finance from the University of California at Berkeley. From 1981 through 1986, I was employed by Standard Oil of Ohio (now British Petroleum-America) in San Francisco as a Petroleum Engineer working on Alaskan North Slope exploration drilling and development projects. From 1987 to 1988, I was employed as a Rates Analyst at Pacific Gas and Electric Company in San Francisco. Beginning in late 1988 until late 1992, I was employed by R.W. Beck and Associates, an engineering and consulting firm in Seattle Washington, conducting cost-of-service and other rate studies, carrying out power supply studies, analyzing mergers, and analyzing the rates of Bonneville Power Administration and the Western Area Power Administration. I came to the WUTC in December of 1993, where I have held a number of positions including Utility Analyst, Electric Program Manager, and the position that I presently hold. I have been a witness in numerous proceedings before the WUTC. I have been a witness in proceedings at the Bonneville Power Administration and at the Federal Energy Regulatory Commission.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present Staff's analysis and recommendations regarding Avista's Energy Recovery Mechanism ("ERM") annual filing for the period July 1, 2002 through December 31, 2002.

Q. How is your testimony organized?

A. I have organized my testimony into eight sections as follows:

Q. Are you sponsoring any exhibits with your testimony?

A. Yes. I am sponsoring Exhibit Nos. ___(APB-2), ___(APB-3), and ___(APB-4).

II. SUMMARY OF RECOMMENDATIONS

Q. Please summarize Staff's recommendations in this proceeding.

A. Staff makes the following recommendations:

A. The Commission should provide clarification regarding "ordinary" and "extraordinary" variations in power supply expenses in the context of the ERM annual review. Staff recommends that any item or action affecting power supply expenses other than normal weather variations, normal variations in water conditions, reasonable variations in wholesale prices, and normal day-to-day operations, should be considered an "extraordinary" variation, requiring a specific request for relief under the ERM. There should be no presumption that any such item or variation is recoverable under the ERM.

B. In future annual review filings, Avista should provide complete testimony and full support, including all documents, studies, and analyses, for all of the costs Avista proposes to be recovered under the ERM. In addition, the Company should provide all studies and analyses that support the Company's decisions to enter into alternative arrangements that affect the four power supply accounts tracked in the ERM.

C. Avista should be ordered to defer and amortize the Enron contract termination payment over the three-year life of the original purchase power agreement. The ERM balance as of December 31, 2002 should be reduced by $1,769,243. Staff recommends Avista record the buyout costs as a regulatory asset to be amortized from January 2004 through December 2006. A carrying charge at the same rate as the ERM interest rate may be accumulated for recovery.

D. Staff recommends that costs associated with future extended outages at any of the Company's generation facilities be treated as "extraordinary" variations in power supply expenses for purposes of future annual ERM review filings. As such, the Company should clearly identify and request specific relief of any excess power costs due to the extended outages. A complete description of the event, along with a demonstration of the prudence of Company actions regarding the event should be provided. Any change in power supply resulting from the event should be explicitly identified.

E. Staff recommends the Company be required to adopt a strategy of using only the shorter-term month ahead markets in disposing the gas associated with the fixed-price gas contracts.

F. Staff recommends that ratepayers, through the ERM, not bear the increased costs associated with the extensive delay related to the Coyote Springs II generating facility. The ERM balance, as of December 31, 2002, should be reduced by $1.999 million. This adjustment reflects an estimate of the net cost to ratepayers of having Coyote Springs II in rates for the six-month review period. Ratepayers should not have to bear those costs, and the increased actual power supply expenses of not having the project available due to numerous delays.

G. The total recommended reduction in the ERM balance, as of December 31, 2002, amounts to $3,768,243.

III. THE CURRENT STATE OF AVISTA'S DEFERRAL BALANCES

Q. What amount of power cost deferrals did the Commission approve for recovery under the current surcharge?

A. The effective balance approved by the Commission in Docket No. UE-011595 was $114, 047,143. This balance was termed the "Energy Cost Deferral Balance."

Q. What is the Energy Cost Deferral Balance as of Avista's most recent report?

A. According to Avista's monthly reports, the $114,047,143 deferral balance as of June 2002 has been reduced to $92,464,598 as of July 2003. So Avista has recovered approximately $21.6 million of the $114 million in deferred power costs.

Q. If the current surcharge remains in effect, when will the $114,047,143 be reduced to zero?

A. At the current rate of amortization and surcharge collections, the original balance will approach zero in about September 2007.

Q. With respect to new power costs Avista has incurred since June 2002, has Avista been able to manage those power costs within the band approved in Docket No. UE-011595?

A. No. From July 2002 through December 2002, Avista recorded additional deferrals of $18,418,548. As of July 2003, the additional deferrals from July 2002 have increased to $29,938,073.37.

Q. If Avista keeps adding deferred power costs at the same levels as the period July 2002 to July 2003, what will the deferral balance be in September 2007?

A. If current trends of additions and collections continue, the ERM could show a balance of over $173 million by the time the original balance reaches zero.

IV. OVERVIEW OF THE ENERGY RECOVERY MECHANISM AND THE SCOPE OF THIS PROCEEDING

Q. What is the scope of this proceeding?

A. This proceeding is called for under the Settlement Stipulation approved by the Commission in its Fifth Supplemental Order in Docket No. UE-011595, dated June 18, 2002. Under Paragraph 4(b) of that Settlement Stipulation:

> The Company agrees to make an annual filing on or before April 1st of each year to provide opportunity for the Commission and interested parties to review the prudence of and audit the ERM deferral entries for the prior calendar year.

Since the deferrals described in that paragraph did not begin until July 1, 2002, this proceeding is to review the deferrals from July 1, 2002 to December 31, 2002 under the ERM.

Q. Will rates change because of this review?

A. No. Under Section II, Paragraph 1 of the Settlement Stipulation, the surcharge will remain in place until the Energy Cost Deferral Balance reaches zero. The Energy Cost Deferral Balance (as defined in Section II, Paragraph 2) includes the authorized recovery of power costs through June of 2002 ($114,047,143), plus any additions from the Energy Recovery Mechanism (ERM). This would include the approximately $18.4 million that is the subject of this proceeding. When the Energy Cost Deferral Balance reaches zero, the existing surcharge tariff, Schedule 93, will terminate. Once that occurs, Section II, Paragraph 4(f) of the Settlement Stipulation allows Avista to change rates to recover deferrals, but only after the deferrals exceed 10% of base retail revenues. That level was $27.8 million, based on the rates approved by the Commission in Docket No. UE-011595.

Q. Please retrace the events that led to the Settlement Stipulation in Docket No. UE-011595.

A. The Settlement Stipulation followed a series of dockets related to problems Avista experienced because it was short on resources during a time in which power markets were quite volatile, and energy prices were high.

In Docket No. UE-010395, the Commission granted Avista a 25% surcharge over existing rates, effective October 1, 2001, to be used to offset power costs deferred pursuant to prior Commission orders in Docket Nos. UE-000972 and UE-011597. This 25% surcharge was allowed to remain in effect subject to a prudence review of the deferred power costs.

The prudence review of those deferred power costs occurred in Docket No. UE-011514, in which the Company asked the Commission for an order finding that some $196 million in deferred power costs were prudent and recoverable. That docket was consolidated with Docket No. UE-011595, a general rate increase filing, in which the Company sought to raise its rates 22.5%, over and above the 25% surcharge.

The Commission approved settlements in those dockets, resulting in a 6.2% increase in general rates and a 25% surcharge to pay down some $114 million in deferred power costs as of June 2002. These rate increases remain in effect today. The Settlement Stipulation also resulted in the Energy Cost Recovery Mechanism (ERM), which called for the proceeding at hand. Under Section II, Paragraph 1 of the Settlement Stipulation, of the 31.2% in rate increases that were granted (25% surcharge plus 6.2% general rate increase), 11.9% is used to offset recoverable deferred power costs.

Q. Please describe the context of the Settlement Stipulation in Docket No. UE-011595.

A. I have already described the very large power cost deferrals that were already on the Company's books, and the very large rate increases that had been granted, or were pending.

In addition, as the Commission described on pages 12-14 of its Fourth Supplemental Order in Docket Nos. UE-011595, Avista's bond rating had been downgraded to below investment grade, yet the Company had a substantial need to refinance and obtain new capital for its pending projects. The most significant of these projects was the Coyote Springs II Project, which the Company originally said would be on line in June 2002.

When the Commission approved it, the Settlement Stipulation resolved the Company's rate case request and its request for a power cost recovery mechanism.

Q. What were Staff's main concerns about the deferred power costs and the level of the Company's rates?

A. Commission Staff was very concerned about the rapid increases in the Company's rates caused by very large power cost deferrals, and their impact on customers, as well as the deterioration of the Company's financial condition.

Staff was also very concerned about the Company's strategy of fixing the price of 40,000 decatherms of natural gas. This gas had been acquired through long-term contracts to meet the needs of the entire Coyote Springs II project. Avista did not transfer any of those gas contracts when it later sold one-half of its interest in the project. From Staff's perspective, this was the reason for the "band" feature of the ERM, which prevents Avista from seeking recovery of the first $9 million in deferred power costs each year. This was explained on pages 13-14 of the "Memorandum of Commission Staff" dated June 3, 2002, Exhibit No. 14 in Docket No. UE-011595.

In addition, Staff believed that the completion of new projects such as Coyote Springs II would also "provide benefits in the form of firm energy supply and a reduction in exposure to the more volatile wholesale markets." "Memorandum of Commission Staff" (June 3, 2002) at page 15, Exhibit No. 14 in Docket No. UE-011595.

Accordingly, Staff was willing to support the ERM, the existing 25% surcharge, and the 6.2% increase, because hopefully, if the Company prudently managed its power costs, including timely completion of the Coyote Springs II Project, the deferral balance could be reduced over time.

Q. Has the 25% surcharge been effective in reducing the $114 million in deferred power costs the Commission found to be recoverable before the ERM was implemented?

A. The surcharge has provided on average about $2.1 million per month to work off the June 2002 balance. As I described earlier, at this rate, the original $114 million approved in Docket No. UE-011595 will approach zero in approximately four years, or September of 2007. However, additional deferrals are being added at levels well above the base level approved in Docket No. UE-011595.

V. DESCRIPTION OF THE COMPANY'S PROPOSAL

Q. Please describe Avista's proposal in this docket.

A. The Company is proposing to include in its deferrals for later recovery over $18 million of costs through the ERM, after adjusting for the band and ninety-percent sharing. Of the almost $25 million in "excess" power costs, over $14.8 million is directly related to the loss Avista experienced by selling out-of-the-market fixed-price gas. This amount reflects only the six-month period under review in this proceeding. During that six-month review period, Avista's purchased power costs exceeded the "authorized" level by over $21.6 million.

Q. What is revealed by this level of power costs Avista has deferred over just the last six months of 2002?

A. While these increased costs were caused by a variety of factors, these deferred amounts indicate the ratepayers continue to be impacted by the Company's decision to hedge or fix the price of certain natural gas contracts, and the fact that the Company was unable to get the Coyote Springs project on line as promised. Staff cannot emphasize enough that it expected Coyote Spring II, and its efficient generation, to be operational coinciding with the time the ERM was in place. Staff believed this plant would minimize ratepayer exposure to unfavorable market prices and mitigate the effects of out-of-market fixed-priced gas. I will discuss these issues in more detail later in my testimony.

VI. THE NATURE OF POWER COSTS TO BE DEFERRED UNDER THE ERM, AND STAFF'S RESPONSE TO AVISTA'S CRITICISM OF THE ANNUAL REVIEW PROCESS IN THIS DOCKET

Q. What specific issues are raised by Avista's filing that relate to how the ERM is operated and how it is reviewed?

A. There are two issues: 1) defining what are "ordinary" and what are "extraordinary" variations in power supply expenses, and how they should be treated for purposes of the ERM review; and 2) whether the Company's apparent criticisms of the procedures for conducting the annual review of deferred power costs are valid.

Q. Turning to the first issue, did the Commission describe the nature of the power costs that could be deferred under the ERM?

A. Yes. The Commission's Fifth Supplemental Order in Docket No. UE-011595 clarified the nature of power costs that are to be recovered through the ERM. On page 15, in paragraph 38 of that Order, the Commission stated: "We also clarified through colloquy with the witnesses, that the ERM is intended to address <u>only the ordinary variations in power costs that may occur going forward, not extraordinary costs</u>." (Emphasis added).

The Order also states that there is nothing precluding the Company from specifically requesting recovery of extraordinary costs, or otherwise seeking modification of the ERM. (Order at page 16, paragraph 39).

The Company has taken the position, through the testimony of Mr. Norwood in this proceeding, that "extraordinary" costs be measured only in terms of dollar magnitude and in context of a total deferral amount. (Exhibit No. ___(KON-T, page 10). Staff does not agree with the Company's limited interpretation of what constitutes "extraordinary" costs.

Q. How should the Fifth Supplemental Order be interpreted on the issue of what are ordinary or extraordinary costs?

A. Staff believes that extraordinary costs can be defined both in terms of dollar magnitude, such as the Company suggests, or in terms of specific events. For example, the existence of a power expense much larger than reasonably expected, no matter the cause, would most likely be considered "extraordinary". At the same time, events such as an extended outage or a contract buyout that are not ordinary variations in power supply expenses and may have a much smaller effect, should also be considered as "extraordinary" for purposes of potential recovery through the ERM. As specified in the Commission's Order, these items require specific requests for relief under the ERM.

Q. Why is this issue important now, when the proposed deferral amount is in the $18 million range?

A. The ERM deferrals under review in this period are caused by several items that Staff believes should be considered extraordinary, and are therefore not recoverable under the ERM unless Avista specifically requests relief, and proves these items should be recoverable from ratepayers. These items include the costs associated with a contract buyout, costs associated with an extended outage at Colstrip Unit No. 3, and costs associated with the delay in operation of the Coyote Springs II generating project. The Company should bear the necessary burden of proof to show that these extraordinary costs are prudent and appropriately recoverable from ratepayers through the ERM.

Q. In this docket, did the Company identify any costs as extraordinary and seek specific relief to recover those costs through the ERM?

A. No. In its June 2003 filing, the Company did, at the request of Staff, address to some extent the items I described. However, it appears the Company's position is that all of the $18.4 million in deferrals for this review period represent ordinary power supply expenses to be recovered under the ERM.

Q. Is Staff recommending denial of these extraordinary costs through the ERM?

A. While Staff believes that the costs identified above are not ordinary variations in power supply expenses, no adjustments to the ERM amounts for this review period are recommended based on this issue alone. However, Staff is recommending that the Commission clarify what should be considered "ordinary" and "extraordinary" variations in power supply expenses and order the Company to include in any future annual ERM filing complete testimony and support for relief of any such costs consistent with that clarification. Staff is concerned that the ERM not become the automatic "catch all" for all power supply-related expenses that may be incurred by the Company. Staff's recommendation is that any item or action that affects power supply other than normal weather variations, normal variations in water conditions, reasonable variations in wholesale power prices, and normal day-to-day operations, should be considered as "extraordinary" for purposes of Avista's annual ERM review filing.

Q. Turning to the second issue, has the Company described the review process in this case?

A. Yes. On pages 4 and 5 of the Company's Exhibit No. ___ (KON-T), Mr. Norwood quotes Section II, Paragraphs 4(a) and 4(b) of the Settlement Stipulation, which address the reporting and annual review requirements. Those requirements are: 1) monthly reporting requirements; and 2) an annual filing to "review the prudence of and audit the ERM deferral entries for the prior calendar year." The tone of Mr. Norwood's testimony appears to be critical of the process that has evolved in this docket. He goes on to express hope that any future annual review could be accomplished within the anticipated 90-day review period. (Exhibit No. ___ (KON-T), page 5).

Q. Is any criticism by the Company of the review process in this case valid?

A. No. The Company has overstated the usefulness of its monthly reports, the extent and context of its annual filing, and what was reasonably envisioned to be accomplished during the 90-day review period, without full and complete support for recovery of the costs deferred.

Q. Can you describe the Company's monthly reports and how the Company suggests they be used?

A. Yes. The Company has provided, and continues to provide, monthly ERM reports. The monthly reports relevant to this review period are in Company Exhibit No. ___ (RLM-1). According to the Company, these contain "extensive information" (Exhibit No. ___ (KON-T), page 5), and together with responses to requests for information within 10 days once the annual filing is made, would form the basis for completing the anticipated review within 90 days. The Company also claims that the costs included in the ERM are "relatively narrow in scope," which apparently would also facilitate any review to be carried out within the 90-day period, in the Company's view. (Exhibit No. ___(KON-T), page 5).

Q. Does Staff agree with Avista's characterization that monthly ERM reports contain "extensive information," sufficient for an adequate ERM annual review?

A. No. The monthly filings provided by the Company fall well short of adequate support for a review of power supply costs to be included for recovery through the ERM. In this instance, the costs included in the ERM are not "relatively narrow in scope," as to allow a complete review within 90 days. Staff is not making the assumption that future ERM reviews will involve only costs that are "relatively narrow in scope," either.

Q. What information does Avista provide in the monthly ERM reports?

A. Mr. Norwood provides a narrative of the information that is provided in the monthly reports. (Exhibit No. ___ (KON-T), page 6). However, it is useful to actually examine the individual monthly reports contained in Exhibit No. ___ (RLM-1) to confirm what is contained in those reports.

Beginning with the July 2002 monthly report, Avista includes a brief, one page cover letter; two pages of General Ledger Journal entries; five pages of General Ledger printouts by account (all related to accounting for the ERM accrual amount); one page related to the interest calculation on the ERM balance; and seven pages related to the determination of the actual surcharge revenue and amortization. Finally, on page 16 of 19, the report includes a summary sheet showing the calculation of the monthly deferral amount, which is followed by two pages summarizing system power supply expenses for accounts 555, 447, 501, and 547. The report ends with a one-page sheet calculating the ERM energy credit. No other support, analyses, or work papers are provided.

The August 2002 report contains virtually the same information, as does the September 2002 report. The reports for the remaining months of the review period contain the same information, except the October and December 2002 reports include attachments that describe long-term power transactions that were entered into during these months.

These monthly reports contain no other detail supporting the costs Avista propose to be recovered through the ERM. For example, there is no detailed support for the approximately $22 million ($14.7 million Washington jurisdiction) in out-of-market natural gas costs included in the ERM filing. Nor is there any thorough explanation or support for the significant differences between "authorized" and "actual" amounts in the four power supply accounts that are tracked in the ERM, other than a few brief sentences in the cover letters.

Q. Is the information Avista provided in the monthly reports different than Staff anticipated would be provided?

A. No. Staff anticipated that the monthly reports would provide the kind of general information the Company does indeed file.

Q. Then what is the issue that Staff has with these filings?

A. The Company has suggested its monthly reports, together with some minimal annual filing, are sufficient to justify the recovery of millions of dollars of power supply costs through the ERM. In fact, the information in Avista's monthly filings does not prove that recovery of these costs through the ERM is appropriate.

Q. What information is lacking in the Company's monthly ERM reports that would facilitate a complete review within the 90-day review period?

A. What is needed is a complete set of all work papers, as well as any studies, documents, and analyses supporting all power supply costs, including any decisions made by management resulting in costs proposed for recovery through the ERM. Depending on potential issues brought out by the review, more extensive analysis by Staff and the intervening parties may be required. Experts may have to be retained, and testimony prepared if there are disputes.

From a practical standpoint, it is not possible to conduct a complete review of all of the costs on an ongoing monthly basis.

Q. Are you recommending that Avista provide complete supporting testimony and work papers as part of each monthly filing?

A. No. The monthly filings serve the intended purpose: to inform the parties of deferral amounts and to provide a brief explanation of major factors affecting the deferral balances. The parties may ask additional questions or clarification of deferral items each month, but it remains the primary purpose of the annual filing for the Company to carry its burden to prove the prudence and recoverability of costs through the ERM.

Q. Is your testimony consistent with the language in Section II, Paragraph 4(b) of the Settlement Stipulation?

A. Yes. The Settlement Stipulation clearly states that it is the annual filing that provides the opportunity for the Commission and interested parties to "review the prudence of and audit the ERM deferral entries." (Settlement Stipulation at page 6, Section II, Paragraph 4(b)). Staff considers the annual filing to be the principal vehicle in which the Company must demonstrate the prudence and recoverability of costs under the ERM.

Q. Did the Company make an annual filing for this review period?

A. Yes, the Company made a filing on March 28, 2003. However, that filing was inadequate to permit a meaningful review. A subsequent filing was made on June 23, 2003, which contains direct testimony and exhibits.

Q. What should the annual filing contain?

A. As I indicated earlier, in future annual filings the Company should provide testimony and full support, including all documents, studies, and analyses, for all of the costs proposed to be recovered, not just for those issues that may have been specifically identified by other parties. In addition, the Company should provide all studies and analyses that support the Company's decisions to enter into other arrangements (such as contract buyouts) that affect the four power supply accounts in the ERM.

Q. Will this allow for the annual review to be carried out within the 90-day period stated in the Settlement Stipulation?

A. Possibly. However, the Settlement Stipulation contemplates that the Commission can permit additional time if necessary.

VII. SPECIFIC COST ISSUES

A. Enron Contract Buyout

Q. Please describe the Enron purchased power contract buyout.

A. The Company is proposing to recover through the ERM the "net" costs associated with the buyout of a multi-year purchase power contract with Enron. Company witness Mr. Storro addresses the buyout in his testimony. (Exhibit No. ___ (RLS-T), page 3). The Company also provided a confidential attachment to its monthly deferral report for October that explained the Company's decision to buyout the contract.

Q. What are the issues related to Avista's buyout of the Enron purchased power contract?

A. There are two issues: 1) the prudence of Avista's buyout decision; and 2) the proper treatment of the buyout related costs under the ERM.

Q. In your opinion, was the Company prudent in buying out the Enron contract?

A. Yes. The benefits Avista received are in large part due to the removal of uncertainty caused by the bankruptcy of Enron. The Company is benefiting from full recovery of outstanding receivables from the same party as the purchase power contract: Enron Power Marketing, Inc. Payment to Avista for a portion of those receivables was in doubt due to the bankruptcy. The contract termination effectively results in full recovery of those receivables. Regarding the purchase power contract itself, the benefits to Avista were based on a favorable discount rate of the mark-to-market amount and the removal of risk associated with potential non-delivery of the power.

Q. How did Staff evaluate the prudence of the contract buyout?

A. The first issue Staff addressed was whether the Company would have been better off doing nothing. Under this scenario, Avista would continue to petition for the receivable recovery in the EPMI bankruptcy process, and assume that EPMI would continue to be able to deliver the contracted power beginning in 2004. Due to the bankruptcy there would remain some uncertainty whether EPMI could actually deliver the power in 2004.

On balance, Staff agrees with the Company that the termination agreement balances the risks and benefits of potential scenarios, all of which were uncertain due to the nature of bankruptcy proceedings. Staff believes the full recovery of the receivable amounts out-weights any potential benefit of EPMI defaulting on the purchase power contract and removes that risk from the resource portfolio.

Q. How does the Company propose to treat the Enron contract buyout?

A. The Company has recorded the total discounted mark-to-market amount of approximately $ 2.9 million as a current purchased power expense for the month of October 2002. The entire amount is included in the Company's ERM calculation for that month, reflecting full recovery in this ERM review period. The receivables credit will clear all accounts with EPMI. These receivables have previously been reflected in prior power cost deferrals.

Q. Does Staff agree with Avista's proposed treatment of the Enron contract buyout in the ERM?

A. No. The discounted mark-to-market contract termination costs should be amortized over the delivery period of the contract, rather than be recorded in a single month. In this manner, the costs match the benefits during the term of the original contract, which was the period 2004 to 2006. This treatment is consistent with similar situations in the past.

Staff's proposed treatment also avoids any issues regarding the immediate period expensing or recognition of costs and revenues associated with these type of transactions, and how they might affect the ERM calculations, particularly the issue of whether or when the dead band has been exceeded.

Q. How should the amortization amount be calculated and accounted for?

A. The Company should be ordered to defer and amortize the contract termination-related payment over the three-year life of the original purchase power agreement. Washington's allocated share of the termination amount should be deferred and a carrying cost would be recorded monthly on the unamortized balance in the deferral account. During the three-year period 2004 through 2006, an amortization of the deferral account, including an amortization of the carrying costs, should be recorded as power costs and included in the ERM calculation. There would be no changes to the ERM methodology.

Q. What is the dollar impact of Staff's recommendation to amortize the Enron contract buyout expense?

A. Avista recorded $1,937,955.21 (Washington jurisdiction) to Account 555, Purchased Power in October 2002 related to this item. This increased the ERM balance by 90 percent of that amount: $1,744,160. The ERM balance at December

2002 should therefore be reduced by $1,769,243 ($1,744,160 plus $25,083 of interest). Staff recommends Avista record the buyout cost as a regulatory asset to be amortized over the original life of the contract: January 2004 through December 2006. A carrying charge at the same rate as the ERM interest rate may be accumulated for recovery. Avista is made whole by this treatment.

Q. Should contract buyouts such as this be considered as "extraordinary" items and require specific requests for relief under the ERM?

A. Yes. As I discussed earlier, this is what was anticipated in the Commission Order. It is clear that contract buyout costs are not "ordinary variations in power costs." This particular contract buyout has limited effect until 2004, other than including the carrying cost in the ERM calculations. Contract buyouts, buydowns, and early retirements do occur on occasion, and the Company should not be penalized for taking prudent actions regarding them. However, the Commission Order does require a specific request for relief if the Company is proposing recovery of the costs or benefits under the ERM.

The Company did, in this specific instance, notify the parties of this buyout transaction and provided support for that decision and its proposed treatment of the costs. Staff recommends that the Company continue to provide notice of these types of actions taken by the Company in its monthly reports. In addition, the Company should provide testimony supporting the recoverability of such costs under the ERM and any accounting treatment. Staff also recommends that the costs (or revenues) associated with these types of events be amortized over the life of the original contract or asset, unless specific circumstances require a different treatment.

B. COLSTRIP OUTAGE

Q. Please summarize the issues related to the extended outage of the Colstrip Unit No. 3.

A. The Colstrip Unit No. 3 is a large coal fired generating plant. It experienced an extended outage, beginning on November 22, 2002. As part of the repair process, a manufacturing error was discovered which required shipping the part back to the factory for a total rebuild. Although the length of repair appears to have been mitigated by the use of a spare part originally designated for Colstrip Unit No. 4, the outage has extended into 2003.

The Company is attempting to recover the additional review period power supply costs related to this outage through the ERM deferrals in this proceeding. As I discussed earlier in my testimony, the increased power supply costs resulting from an extended outage of this nature is not an "ordinary variation" in power supply costs that the ERM is intended to address. Clearly, an outage that begins on November 22, 2002 and extends into 2003, and that requires the use of a part designated for another unit, is "extraordinary."

Q. Has the increase in power supply costs from this extended outage been determined?

A. Yes. The Company has carried out an analysis estimating the lost margin due to the outage from November 22, 2002, through December 31, 2002. That analysis shows an estimated value of lost generation of just over $2.5 million on a system basis, or $1.7 million for the Washington jurisdiction. Staff considers this a significant increase in expenses.

Q. Has the Company specifically sought relief for outage related costs as allowed under the Settlement Stipulation?

A. No. The Company has treated the outage simply as resulting in an ordinary variation in power supply expense. In Avista's monthly reports, the outage was identified as being a cause for increased expense levels. The Company apparently does not consider either the event, or the increased costs, as being "extraordinary." It was only at the request of the Staff and intervening parties that the Company addressed this issue explicitly in its annual filing.

The Company apparently believes this outage is not unusual on the basis that even with the 40 days of outage in 2002, the five-year average availability factor is above the factor used to set base rates. (Exhibit No. ___ (RLS-T, page 5).

Q. Can you comment on this availability factor point made by the Avista?

A. The Company includes the 2002 outage period for this event in its calculation of a five-year average availability factor, but ignores the fact that the outage continued into 2003. But even if the outage did not affect a five-year availability factor, that does not mean the resulting effect on power supply expenses should be considered as an ordinary variation.

Q. What is Staff's recommendation regarding the increased power supply costs associated with the extended outage of the Colstrip Unit No. 3?

A. Staff is not recommending an adjustment to the ERM deferral balance due to the extended outage. However, Staff is recommending that future extended outages of any of the Company's facilities should be considered "extraordinary" events. The Company should clearly identify and request specific relief of excess power costs due to extended outages. For purposes of the annual ERM review, extended outages can be defined as those outages longer in duration than planned maintenance outages and have a material effect on power supply costs.

If the Company seeks recovery of such costs under the ERM, it should include a complete description of the event, along with a demonstration of the prudence of Company actions regarding the event. Any change in power supply costs resulting from the event should be explicitly identified.

C. FIXED-PRICE GAS PURCHASES

Q. Please describe the fixed-price gas purchase issue.

A. In managing its portfolio of gas purchase contracts, the Company elected to hedge various index-priced gas contracts by fixing the price, at levels that subsequently have been considered out-of-the-market. During this review period, the increased fuel expense associated with these contracts is approximately $14.8 million for the Washington jurisdiction. This compares to the approximately $18.4 million total deferrals Avista proposes in this proceeding. (Exhibit No. ___ (KON-T), page 7). The review and analysis of the Company's management of these contracts is a prime purpose of the ERM. The analysis is complicated because of the relationship between electric and gas market prices, costs of generation, and load/resource positions.

Q. What is Staff's understanding of the Company's approach to fixed-price gas contract management?

A. Company witness Mr. Storro describes the management objective as one that minimizes the total power expense of the Company. (Exhibit No. ___(RLS-T), page 6). Mr. Storro explains this is accomplished by meeting load requirements based on the cheaper of generation or purchases, as well as determining whether selling gas outright results in overall lower power supply expense for the period. Finally, the Company often sells gas months ahead of the delivery period, either with corresponding power purchases, or without.

These management objectives are also summarized in the Company's responses to Staff Data Requests No. 179(C) and 180(C). A summary of gas sales transactions was also provided in response to Staff Data Request No. 178(C), as was the detailed documentation for each sale. Overall, the Company has estimated a reduction in overall power supply costs of $4.4 million from the resale of the fixed-price gas during this six-month review period compared to the cost of generating electricity with the gas. In other words, Avista's management of its fixed-price gas contracts resulted in reducing its losses associated with the out-of-market contracts from $19.2 million to $14.8 million for the Washington jurisdiction. As discussed later in my testimony, this amount is without Coyote Springs II having been available.

Q. Please describe Staff's review of the Company's management of the fixed-price gas contracts.

A. Staff reviewed the Company's detailed support for each of the gas sales transactions related to the fixed-price contract gas. The Company's analysis generally supported its gas resales decisions, showing that it was more beneficial to sell all of the fixed-price gas during this review period. This was due to the generally unfavorable market price of energy during this period, compared to the market price of gas. It was also due to the relative inefficiency of the gas-fired resources available to the Company.

With the exception of Avista's sales of gas into the longer-term market, Staff accepts the Company's management of the fixed-price gas contracts for the July 2002 through December 2002 review period. This does not reflect any adjustments due to Staff's recommended treatment of Coyote Springs II delays, which I discuss later in my testimony.

Q. Please give an example of the Company's sales of gas into the longer-term market.

A. Prior to the beginning of the review period and in the early months of the review period, the Company sold gas well into the forward market. For example, in April 2002, the Company sold 10,000 decatherms per day of the fixed-price gas for delivery in November and December 2002. Corresponding purchases of electric energy may or may not have been made in order to maintain resource positions. Based on the specific documents Avista provided to support each such transaction, the decision to sell the gas well into the forward market is generally based on the Company's resource-load position reports.

In these reports, Avista looks at forward gas prices and forward prices of electric energy. If the Company is long in a future month, then the gas may be sold without a corresponding purchase of energy. If the Company is short in a future month, the gas may be sold with a corresponding purchase of energy.

Q. What is Staff's concern with this approach?

A. As I described earlier in my testimony, at the time of the Settlement Stipulation and formulation of the ERM, Staff was concerned with the prudence of the Company's decision to fix the price of certain index-based gas contracts. This concern was heightened when the Company sold half of its interest in the Coyote Springs generating facility, but retained all of the gas that it had contracted to serve that facility.

In supporting the ERM portion of the Settlement Stipulation, Staff did not anticipate the Company selling gas at fixed-prices into future (longer than month ahead) markets. In Staff's view, it was the combination of Coyote Springs II coming on-line plus the potential for Avista to take advantage of the shorter-term electric and gas markets that would give Avista the best chance to mitigate the out-of-market fixed-price gas contracts.

Avista's strategy of selling the gas into the future market limits any opportunity for the Company and ratepayers alike to benefit from the shorter-term markets.

Q. Why should the Company have based its gas sales decisions regarding the fixed-price gas contracts on the shorter-term month ahead market?

A. These markets provide the best opportunity for mitigating the out-of-market fixed-price gas contracts.

Q. Why does reliance upon short-term month-ahead markets provide the best opportunity for mitigating the costs associated with the out-of-market fixed-price gas contracts?

A. Fixing the future price of the gas sold may "lock-in" costs that that would otherwise have the potential to be mitigated under the ERM. The Company eliminates uncertainty this way, but at the expense of potential benefits. By relying on the short-term markets rather than selling gas months ahead, the Company and ratepayers can take advantage of the short-term markets. There is risk associated with this approach, if month ahead prices end up being lower than what could have been obtained in the longer-term future market. However, Staff believes the risks/benefits are not symmetrical.

An example of this is shown in my Exhibit No. ___ (APB-2). In April 2002, the Company sold 10,000 decatherms per day of gas for delivery from November 2002 through October 2003, at an average price of $3.585 per decatherm. These are the third and fourth contracts listed in the Company's Exhibit No. ___ (RLS-2). My Exhibit No. ___ (APB-2) lists the Inside FERC First of Month index prices for Malin over the delivery period. The prices for April 2002 through October 2002 are listed as well.

As indicated in Exhibit No. ___(APB-2, the difference between the $3.585 price and the monthly index prices approximates the benefits the Company did not obtain by choosing to sell the gas so far forward. For the month of March 2003, this represents the loss of benefits of over $1.2 million alone. To be fair, there is a risk that the month ahead price would be below the $3.585 average price of the forward gas sale. However, that risk is not symmetrical between these two ways of managing the portfolio.

For example, assume the beginning month index price could have gone as low as $2.47 as it did in August 2002. August typically has lower gas prices than other months due to lower demand. Or the index could advance to a high point of $7.53 such as it did in March 2003. The largest “downside” potential amounts to $1.115 for any month ($3.585 - $2.47 = $1.115), compared to the potential upside of $3.945 ($7.53-$3.585).

The purpose of this example is not to evaluate pricing decisions in hindsight, but rather to show how the ERM can take advantage of the non-symmetrical month ahead gas markets to mitigate the cost of the out-of-market fixed-price gas contracts previously entered into by the Company.

The Company’s decision to instead sell fixed-price gas well into the future market may have removed uncertainty to the Company, but it failed to maximize the potential benefit to ratepayers. The ERM was designed to maximize those benefits, given the difficult situation that the Company was facing.

Q. Is Staff recommending an adjustment related to this issue in this proceeding?

A. No. Staff is not recommending an adjustment to the 2002 ERM balance for the period July 2002 through December 2002. However, Staff is recommending that the Company be required to adopt a strategy of using only the shorter-term month ahead markets related to the disposition of the out-of-market fixed-price gas contracts. This should be the strategy until the out-of-market contracts end. The only exception to this strategy would be if the Company could eliminate all of the fixed-price gas uncertainty by locking in future sales with the same delivery periods and at prices equal to or very close to the average price of those gas contracts.

Staff understands that the Company has sold significant quantities of forward futures gas in 2003. This includes the gas sales discussed in the example above. Gas prices throughout 2003 have strengthened. Ratepayers should not be penalized by the Company's discretionary decision to sell fixed-price future gas, which only serves to counter the purpose of the ERM. Any recommended adjustment due to these sales will be the subject of the 2003 ERM review.

Q. With respect to the information the Company did provide, does there always need to be a connection between gas sales and electric purchases?

A. No. Electric power purchases can be made independently of sales of gas related to the out-of-market fixed-price gas contracts. For example, Mr. Storro appears to support the sale of some 2003 fixed-price gas in 2002 based on the fact the Company entered into power purchases at relatively low prices at the same time it sold the gas. (Exhibit No. ___(RLS-T), page 8). The Company's decisions to purchase or to sell electricity forward based on load/resource positions can be made independently. Those decisions do not necessarily need to be tied to the disposition of the gas related to the out-of-market fixed-price contracts, in fact, it is essentially a requirement if the Company is limited to disposing of the fixed-price gas based on the short-term markets.

C. COYOTE SPRINGS II DELAY

Q. What is the Coyote Springs II Project?

A. The Coyote Springs II Project is a highly efficient, gas-fired combined cycle combustion turbine generating facility with an approximate capacity of 280 Megawatts. Avista owns one-half of the project; Mirant owns the other half.

Q. When was Coyote Springs II scheduled to become commercially operational?

A. The Company had submitted testimony in the last rate case that Coyote Springs II was scheduled to begin commercial operation June 1, 2002. The initial transformer problem occurred in mid-May 2002. However, Staff has no recollection of an extended delay of the project being discussed between the Settlement Stipulation date of May 31, 2002 and the settlement hearing on June 12. As late as mid-June 2002, when the Commission's Order was released, Staff had received no information that the project was significantly delayed beyond the initial August 2002 delay date.

Q. Was the commercial operation of the Coyote Springs II Project a significant factor in Staff's consideration of the issues in Docket No. UE-011595?

A. Yes. As stated earlier in my testimony, the imminent commercial operation of the Coyote Springs II generating facility was one of the major reasons why Staff supported the ERM and the overall Settlement Stipulation in Docket No. UE-011595. Staff stated on page 15 of its "Memorandum of Commission Staff" (June 3, 2002) in Docket No. UE-011595: "While these projects [including Coyote Springs] have resulted in upward rate pressure as they are added to the Company's results of operations, Staff believes they will provide benefits in the form of firm energy supply and a reduction in exposure to the more volatile wholesale markets."

Coyote Springs II was to address the long-term resource deficit position of the Company at that time. It was also Staff's view that the high generation efficiencies offered by Coyote Springs II would be pivotal in the mitigation of the out-of-market fixed-price gas contracts discussed earlier. This would not only include "in-the-market" sales of electricity generated by the project, but also sales of electricity that would result in less of a loss compared to selling the gas outright.

Q. Please summarize Staff's analysis of the Coyote Springs II Project in Docket No. UE-011595.

A. In that docket, Staff concluded the project was prudently acquired and that the Company should be allowed to recover from ratepayers the associated costs, including capital costs, interest, depreciation, and non-fuel O&M costs on a prospective basis.

Q. What assumptions were made regarding the commercial operation of Coyote Springs II project at the time of the settlement in Docket No. UE-011595 and the beginning of the ERM, in July 2002?

A. As I stated earlier, the Company's testimony in that docket anticipated a commercial operation date for Coyote Springs of June 1, 2002. Staff accepted the Company's Pro Forma Coyote Springs Adjustment in that docket. In addition, embedded in the "authorized" level of power supply expenses established in that docket is the fuel cost associated with operating Coyote Springs II at normalized levels. Subsequent to the rate filing, the project was delayed until some time in August 2002.

Thus, incorporated into present base rates for the Company are the costs associated with Coyote Springs II. Specifically, for purpose of setting rates, the net increase in rate base for the Washington jurisdiction was $58,466,000 associated with Coyote Springs, along with an increase of approximately $4.72 million for operating costs exclusive of fuel on an annual basis.

The authorized level of power supply expense used in the ERM includes the normalized gas costs for Coyote Springs II at an annual level of approximately $12.7 million for the Washington jurisdiction.

These amounts are presented in Exhibit No. ___(APB-3) on both a total system and Washington jurisdiction basis.

Q. What is the authorized level of normalized fuel costs for Coyote Springs in the ERM for this review period?

A. For the review period July 2002 through December 2003, the authorized level of power supply expense includes approximately $7.139 million of fuel expenses related to Coyote Springs II for the Washington Jurisdiction. This represents approximately 98 average MW of generation during the six-month review period.

Q. Did Coyote Springs II generate 98 average MW of electricity during the review period July 2002 to December 2002?

A. No. It did not begin commercial operation until July 2003.

Q. What caused the delay in bringing Coyote Springs II on line as scheduled?

A. There were two main factors that caused delay: 1) the bankruptcy of Enron; and 2) a series of significant events related to a transformer.

Q. Please describe the delays due to the Enron bankruptcy.

A. The Enron bankruptcy delayed the project about two months. Avista Power had selected NEPCO, an Enron subsidiary, as the contractor for the project. Because of the bankruptcy, NEPCO was unable to fulfill its contractual obligation to complete the Coyote Spring II Project. In the first quarter 2002, the Coyote Springs II partners took over the role of contractor, a process that included replacing the existing construction staff.

Q. If the Enron situation caused a two-month delay, did Coyote Springs II begin commercial operation in August 2002, two months after the June 2002 expected completion date?

A. No.

Q. Why not?

A. In May 2002, the Coyote Springs II transformer experienced an internal failure, resulting in an oil spill and fire. In subsequent months, the transformer was shipped to a repair facility and various components were sent elsewhere for testing. Since the damage was extensive, the partners, Avista Power and Mirant, began to investigate options to replace the transformer.

Ultimately, the partners decided to obtain a second transformer from the same supplier. In August 2002, the second transformer failed a factory test that required the transformer to be disassembled and repaired. When the second transformer arrived on site in December 2002, it was damaged. After a significant amount of analysis on how to move forward, the partners decided to have the second transformer repaired. The transformer was repaired and subsequently energized at the site at the end of May 2003. After testing, commercial operation of the plant finally began in July 2003, more than one year after it was assumed to be available in Docket No. UE-011595.

Q. Has specific responsibility been determined for the problems related to either transformer?

A. Not to Staff's knowledge.

Q. Will the Company obtain any relief in the form of insurance recovery for the increased costs associated with the transformer problems?

A. The Company has testified that the insurers have indicated they will pay for the replacement transformer and a portion of the costs to clean up the site due to the oil spill. (Exhibit No. ___ (TJC-T), page 9).

Q. In this proceeding, is Staff addressing the prudence of the Company decisions regarding the significant delays associated with the Coyote Springs II project?

A. No. The issues of prudence and recoverability of the direct costs issues related to the original transformer damage, repairs, replacement costs, and site cleanup are subjects for the Company's next general rate case, as is the treatment of proceeds obtained from insurers. Avista is not requesting recovery of these amounts at this time.

The issues in this proceeding are the effect of the delay in commercial operation of Coyote Springs II on the ERM deferral balances, and whether ratepayers should be responsible for the majority of the increased costs.

Q. Prior to being placed into service in July 2003, was Coyote Springs II investment placed into an electric plant-in-service account on the utility's books of account?

A. No. On January 1, 2003 the Coyote Springs II plant was transferred from Avista Power to Avista Utility as Construction Work in Progress.

Q. Does that mean the project was not included in Washington jurisdiction rate base for ratemaking purposes in this state as a result of Docket No. UE-011595?

A. No. Coyote Springs II was included in rate base through a pro-forma adjustment for purposes of setting rates. Moreover, in the Commission-basis annual report for 2002 that Avista filed with the Commission, Coyote Springs II investment was included in rate base, and Coyote Springs II normalized operating expenses were included in normalized power supply expenses.

Q. How should the Coyote Springs II delay in commercial operation be treated for purposes of determining recoverable ERM deferral balances?

A. Ratepayers should be held harmless from the effects of the delay.

Q. What is the basis for this recommendation?

A. The failure of Coyote Springs II to begin commercial operation on the date anticipated at the time of the Settlement Stipulation has caused additional costs that the Company is proposing to recover through the ERM. As I described earlier, the imminent commercial operation of Coyote Springs II was pivotal for Staff's support of the ERM. The ERM was specifically designed to take advantage of the resource position of the Company once the project was available, and to aid in the disposition of the out-of-market fixed-price gas previously discussed.

Ratepayers should not be at risk for the excess power supply costs incurred during this review period due to the series of decisions and events that has plagued the Coyote Springs II Project. In addition, the extended delay in the commercial operation of the plant is clearly an extraordinary event and does not meet the Commission's clarification: "that the ERM is intended to address only the ordinary variations in power costs that may occur going forward, not extraordinary costs."

The Company has identified what it believes are the additional costs it incurred due to the delay, and why it believes its decisions regarding the transformer issues were prudent. However, the Company did not explicitly address the issue of why ratepayers should bear ninety-percent of these increased costs through the ERM. Clearly, the costs associated with the delay are not caused by variations in water conditions, normal thermal plant availability, or wholesale power prices, all items anticipated to be addressed in the ERM under the Commission Order. The unavailability of Coyote Springs II significantly affects the mitigation of the out-of-market fixed-price gas contracts.

Q. Did the ratepayers or the Commission cause the delay in the commercial operation date of the Coyote Springs II project?

A. No. The following list briefly summarizes the fateful decisions and events that have taken place regarding Coyote Springs II:

- Avista Power purchased the project site, design, permits, and development rights.
- Avista Power selected NEPCO, a subsidiary of ENRON, as primary contractor.
- Enron filed for bankruptcy in late 2001.
- Enron ceased making funds available to NEPCO to complete the project.
- Coyote Springs II partners take over the role of contractor, with new management and construction staff.
- May 6, 2002: transformer failure and spill.
- The parties cannot reach agreement on the nature of the transformer failure or who is responsible.
- Coyote Springs II partners make the decision to acquire a second transformer from the same supplier.
- August 30, 2002: the second transformer failed a factory test.
- Inspection of the second transformer revealed internal damage.
- Second transformer was repaired at supplier factory.

- Upon delivery of second transformer to project site, additional damage was discovered.
- Second transformer was sent to repair facility.
- May 30, 2003: the second transformer was energized at the project site.
- July 2003: Coyote Springs II finally begins commercial operation, over one year from its original in-service date.

Ratepayers were not involved in any of these events. However, ratepayers are not only paying for the project in rates, but are also being asked to pay most of the costs associated with the delay. Coyote Springs II was allowed in rate base through a pro-forma adjustment for purposes of determining Washington rates, and the normalized fuel expenses associated with the project have been included as authorized power supply expenses.

Ratepayers have been paying those costs since July 1, 2002. They should not be asked to bear additional power supply costs associated with the delay of the project. The ERM deferral proposed by Avista results in ratepayers bearing ninety-percent of the additional power supply costs due to the extended delay of Coyote Springs II.

Q. Wasn't there uncertainty about the in-service date of Coyote Springs II at the time of the Settlement Stipulation?

A. Yes. However, as I discussed earlier, Staff was not aware that Coyote Springs II would experience the extensive delays that occurred, nor was it known that the Company would attempt to recover the incremental power supply costs caused by that delay in the ERM. That possibility was not part of Staff's analysis when developing its position regarding the ERM. The pro-forma adjustment for Coyote Springs II was accepted along with the implementation of the ERM.

Q. Have you calculated the impact of the delay in the Coyote Springs II project on Avista's power supply costs?

A. Calculating the effect on power supply costs of the delay is difficult at best. Staff looked at three different methodologies for such a calculation. First, in response to ICNU Data Request No. 1.10, the Company provided a hypothetical analysis based on calculating the lost margin from the sale of power that would have been economically generated by Coyote Springs II.

The second method involves analyzing the Company's generation and gas sales decisions, assuming that Coyote Springs II was available beginning in July 2002. This methodology recreates the Company's own analysis of generation versus gas sales as presented in support of each of the gas resale transactions.

The third method is to determine the effect on revenue requirements and the ERM deferral balance as if certain expense and fuel costs related to Coyote Springs II were not put into rates beginning July 2002.

Q. Please describe the first method in more detail.

A. In this hypothetical analysis, the Company estimated the lost margin by comparing the Dow Jones Mid-Columbia Index Price of electricity to Coyote Springs II operating costs using Platt's Gas Daily Midpoint Malin Gas Price. The potential margin is calculated on a daily basis for the period August 15, 2002 through December 31, 2002.

Q. What is the result of this first method, according to the Company's calculation?

A. The Company claims the impact of the delay in operation of Coyote Springs II has been relatively minor due to the small "spark spread" during this review period. The Company's analysis results in approximately $1.4 million in margin, on a system basis, that could have been obtained had Coyote Springs II been operational beginning August 15, 2002. This equates to a loss of benefits of approximately $950,000 for the Washington jurisdiction. These lost benefits result in an ERM deferral balance larger than it would have otherwise been had Coyote Springs II been in operation.

Q. Does this first method provide an adequate measure of the additional power supply costs due to the delay of the in-service date of Coyote Springs II?

A. No. The analysis presented by the Company is more of an incremental, after the fact analysis, which assumes that all other decisions would have remained the same. This is not sufficient to evaluate the full impact of the delay. This analysis claims margins only when the project is incrementally economic. A more complete analysis would take into consideration the overall reduction in power supply expense that would have occurred had Coyote Springs II been available.

Had Coyote Springs II been available, the full effect on the ERM deferral balance would only be known if Coyote Springs II was one of the available resources included in an analysis similar to that carried out by the Company as support for its disposition of gas associated with the fixed-price gas contracts. Those analyses address the scenarios of reselling the fixed-price gas or generating electricity, even at a loss, to minimize the Company's overall power supply expense.

Q. Is that type of analysis the same as the second method you described earlier?

A. Yes. The second method simply attempts to recreate the Company's decision-making methodology supporting each of the gas sales transactions listed in Mr. Storro's Exhibit No. ___ (RLS-2). By recreating the Company's own analyses on a transaction-by-transaction basis, assuming that Coyote Springs II was available, and comparing that to the Company's analyses without the project, an estimate of the cost of the delay can be obtained.

Q. Please describe how this second method was carried out.

A. Staff began with the Company's own logic in analyzing its decisions to either dispose of the gas associated with the out-of-market fixed-price gas, or generate electricity and sell into the market. The Company's analyses are summarized Mr. Storro's in Exhibit No. ___ (RLS-2). Staff recreated the analysis of each transaction until a cumulative maximum of 20,000 decatherms per day was actually used by the Coyote Springs II project. This limit is necessary because the availability of the highly efficient Coyote Springs II generation results in changes to the Company's analyses.

Q. What are those changes?

A. Generally, it becomes more favorable to use the gas to generate electricity at Coyote Springs II and sell that electricity into the market, rather than simply resell the gas and not generate. With this result, there then exists the likelihood that Avista would use its total share of the capacity of Coyote Springs II. For purposes of this analysis, Staff limited Coyote Springs II to using 20,000 decatherms per day, equivalent to the approximate maximum generation of Avista's project share. Once that amount of gas was actually forecast to be burned by the project for a particular delivery month, all other analyses remained the same.

Q. What is the result of having Coyote Springs II available?

A. My Exhibit No. ___ (APB-4) summarizes the effect of having Coyote Springs II available. The availability of Coyote Springs II would have offered the Company an opportunity to further reduce overall power supply expenses. This is possible because the same quantity of gas run through Coyote Springs II will generate significant additional quantities of electricity to sell into the market compared to the electricity that could have been generated from less efficient Company-owned plants. Thus, the potential electric sales revenue side of the equation, with Coyote Springs II available, becomes much more favorable. As can be observed, for much of the review period it would have been more beneficial to sell generated electricity than to resell the gas directly. In general, only after all of the Coyote Springs II generation capacity is committed do the analyses begin to resemble the Company's original analysis without Coyote Springs II.

Based on this method, having Coyote Springs II available would have provided approximately $6.02 million in benefits to offset the costs related to the out-of-market fixed-price gas on a system basis. Compared to the Company's claim of approximately $4.38 million (Exhibit No. ___ (RLS-2) without Coyote Springs II, this is about $1.64 million more on a system basis, or $1.1 million more for the Washington jurisdiction for this review period.

Q. Does this second method provide an adequate measure of the additional power supply costs due to the delay in the in service date of Coyote Springs II?

A. No. This method only serves to recreate the decision making process for each of the actual gas sales transactions that were entered into by the Company. Had Coyote Springs II been available, the actual sales Avista made may or may not have taken place on those dates with those prices. For example, if the analysis indicated that a particular sale was not the best option, the gas associated with that transaction would have remained available for future analyses of other options. The ultimate effect on power supply expenses of having Coyote Springs II available would not be known until an analysis is carried out based on actual real time decisions.

Q. Please describe the third method to determine the effect on power supply costs of the Coyote Springs II delay.

A. The third method does not adjust the actual expenses, assuming Coyote Springs II was operational in 2002. Instead, the expense and fuel cost components of Coyote Springs II are removed from the revenue requirements levels adopted in the rate case and Settlement Stipulation. By reflecting the delay in commercial operation of the project in this way, Staff does not have to recreate Company decisions as if Coyote Springs II was in the resource mix. This method also does not require estimating margins from the hypothetical sales of electricity that could have been made assuming the project was available. This method simply reflects the adjustments that Staff would have recommended in Docket No. UE-011595 and at the time of the Settlement Stipulation, if Coyote Springs was not thought to be imminently available.

This method is not ideal, however, because it assumes the ERM would have been supported by the parties without the expected imminent operation of Coyote Springs II.

Q. What was the revenue requirement level (less the revenue sensitive items) associated with Coyote Springs II from the last rate case?

A. Exhibit No. ___ (APB-3, page 1) shows the various Coyote Springs II cost components embedded in rates. The relevant expense levels include Washington jurisdiction amounts of approximately $4.68 million, $ 4.72 million, and $12.74

million for annual amounts associated with return on rate base, operating expenses, and normalized fuel costs, respectively.

Q. What adjustments to power costs should be made as a result of this method?

A. This method would reflect a recommendation that the Coyote Springs II pro-forma adjustment not be accepted, or at least delayed, for the review period. One-half year of expenses related to the project would be removed reflecting the delay. The rate base amount in rates would be removed, but replaced with a like amount in Construction Work in Progress, effectively negating that adjustment. The fuel costs related to Coyote Springs II would not be included as part of the authorized level of normalized fuel expenses. The normalized level of energy assumed for the project, consistent with fuel use, would be adjusted. Exhibit No. ___ (APB-3), page 2 shows this amount to be approximately $7.14 million, Washington jurisdiction, for the six-month review period. Market purchases are assumed to replace the normalized energy amount and expenses levels calculated using the Company's average secondary purchase price in Docket No. UE-011595. This amount has been calculated for the Washington jurisdiction in Exhibit No. ___(APB-3), page 2, and amounts to over $10.76 million for the six-month review period.

Q. What is the net result of these adjustments?

A. Using this third method, an adjustment reflecting the delay in the commercial operation of Coyote Springs II during the six-month review period results in a net $1.999 million reduction in the ERM deferral. This reflects a net reduction of $3.257 million ($3.619 million x 90 percent) in the deferral due to the higher "authorized" level of power supply expenses had Coyote Springs II energy been replaced with purchase power. However, this amount is reduced by $1.258 million of what could be called "underpayment" from base rates lower than they would have been without Coyote Springs II. The net is equal to ninety-percent of the Coyote Springs II expense that was removed for the six-month review period, or $1.999 million. ($2.361 million x 90 percent).

Q. Which of the three methodologies you have identified does Staff recommend be used in this proceeding for adjusting the ERM deferral balance to reflect the delay?

A. Staff is recommending the third method. This method is straightforward, based on known amounts from the general rate case, and it does not require hypothetical analyses of what the Company "could" or "should" have done. All the analyses and decisions that were made with Coyote Springs II not available remain the same. This method also reflects the position that Staff would have taken in the general rate case had the extent of the delay been known at that time. Staff is not proposing to adjust base rates or authorized levels of power supply expense that have been previously established. The recommended adjustment to the ERM deferral balance in this proceeding is simply an attempt to make ratepayers whole by not having to pay both Coyote Springs II costs and the additional costs of not having Coyote Springs II available.

Q. Does that conclude your direct testimony?

A. Yes.