Q. Are you the same Mark T. Widmer who previously testified in these proceedings?

A. Yes.

Purpose of Testimony

Q. What is the purpose of your rebuttal testimony?

A. I will address the following net power cost issues:

- ? The Company's net power cost corrections;
- ? Staff witness Buckley's recommendations regarding (1) the Swift operating reserves correction, (2) proposed water year methodology, (3) proposed Market Cap / Bridger sales adjustment, and (4) the prudence of resources acquired by the Company since the 1986 general rate case;
- ? The recommendations of Staff witness Buckley and ICNU witness Falkenberg regarding proposed adjustments for the Aquila hydro hedge and the Morgan Stanley and J. Aron temperature hedges;
- ? ICNU witness Falkenberg's recommendations regarding (1) overall net power costs, (2) proposed BPA settlement adjustment, (3) proposed adjustments for West Valley, Sempra call and Morgan Stanley call, and P4 Production and Fort James contracts, (4) Wyodak capacity adjustment, (5) proposal to increase the Market size limit, (6) outage adjustments for Hunter 1, CT outage rates, Blundell duration, Dave Johnston Unit 3, Hayden Unit 1, and Colstrip 4, (7) CT Dispatch / Quick Start adjustment, (8) emergency energy purchase adjustment, (9) Gadsby

and West Valley heat rate adjustment, and (10) "market" valuation of new resources.

Net Power Cost Corrections

Q. Has the Company prepared a corrected net power cost study?

A. Yes. In the Company's response to ICNU data request 1.39 (provided in late February 2004) and ICNU data request 5.42, the Company described and quantified ten mistakes in its filed net power cost study. At that time, the Company indicated that the corrections would be reflected in its revised revenue requirement during the rebuttal phase of the case. The corrections increase net power costs from $553.0 million to $558.0 million Total Company. Later in my testimony I adopt ICNU's Fort James and Quick Start adjustments and propose revised modeling for the Wyodak generation facility, based on a recent study. These additional adjustments lower the Company's requested net power costs from $558 million to $555 million Total Company.

Q. Please explain the corrections.

A. The corrections are described below:

- ? The water year weighting inadvertently used the 50-year weighting method instead of the 40-year rolling average method prescribed by the Commission. The correction reduces net power costs by $1.1 million Total Company.
- ? The inability of Swift 1 to carry operating reserves as a result of the outage on Cowlitz's Swift 2 project was not modeled in GRID. The correction increases net power costs by $3.6 million Total Company.

? The reserve capacity on the expired Colokum contract was inadvertently included in GRID. The correction increases net power costs by $0.5 million Total Company.

? The Company's licensing requirement concerning the rate of change of the stream level below Merwin was not properly reflected in GRID. The correction increases net power costs by $1.7 Total Company.

? Forecast payments – rather than actual payments – for the Kennecott Generation Incentive contract were inadvertently reflected in GRID. This correction increases net power costs by $1.0 million Total Company.

? The heat rates associated with the dispatch logic did not match the commitment heat rate curves used in GRID. This correction increases net power costs by $0.2 million Total Company.

? The West Valley heat rate curves were based on manufacturer's estimates. These estimates were found to be higher than actual performance. A revised estimate based on one year of actual data decreases net power costs by $1.7 million Total Company.

? The shape to load attributes for the BPA Peaking contract were entered incorrectly in GRID. The correction decreases net power costs by $1.2 million Total Company.

? The Short-Term Firm data in GRID inadvertently included Redding exchange energy that was already accounted for in the long-term transactions. Correcting the double count reduces net power costs by $1.5 million Total Company.

? The Company had a Market Cap data entry error that caused GRID to inadvertently make an emergency purchase. The correction reduces net power costs by $2.9 million Total Company.

It should be noted that the impact of each adjustment was calculated on a stand alone basis, not incrementally. If all of these adjustments were calculated incrementally, in a different order, or on the basis of adoption of only some of the adjustments, the value would be different because each adjustment affects the other adjustments. Therefore, once the Commission decides which adjustments it is adopting, authorized net power costs should be calculated with the GRID model.

Q. Did Staff and ICNU adopt any of these adjustments?

A. Yes. Mr. Buckley adopted all of the adjustments related to the Company's Western Control Area except the Swift reserve adjustment and several that he assigned to the Company's Eastern Control Area. However, it should be noted that he did not contest the Eastern Control Area adjustments. Mr. Falkenberg adopted the Emergency Energy adjustment and appears to have incorporated the West Valley heat rate adjustment in his Gadsby and West Valley heat rate adjustment, and was silent on the remainder of the adjustments. Therefore, if the Commission rejects Staff's proposed allocation methodology, all of the Company's proposed adjustments should be adopted by the Commission.

Q. Which corrections did Mr. Buckley exclude because he assigned them to the Eastern Control Area?

A. The matching heat rates, West Valley heat rates and Kennecott adjustments.

Staff Witness Buckley's Adjustments

Swift 1 Operating Reserve

Q. Do you agree with Mr. Buckley's reasoning for not adopting the Swift 1 operating reserve adjustment?

A. No. It appears that Mr. Buckley has inadvertently confused the timing of when rates will go into effect for this case. His testimony recommends that the adjustment should be rejected because rates will go into effect in December 2005, or shortly before the Swift 1 project can once again carry operating reserves. On this basis, he does not believe it is appropriate to reflect the short-term effects in future rates. In fact, however, rates from this case will go into effect in November 2004, or 18 months before Swift 1 can carry operating reserves. Therefore, based on the actual timing of this case, the proposed adjustment should be included in rates.

Q. If the Commission were to adopt Mr. Buckley's Swift 1 recommendation, are there other adjustments that the Commission should adopt to be consistent?

A. Yes. Using Mr. Buckley's reasoning, a number of contracts should be removed from net power costs because they are no longer in effect and should not be built into future retail rates. The AEPCO, Puget Sound, and Deseret wholesale sales contracts expired August 2003, September 2003, and October 2003, respectively. The Springfield Utility Board terminated the wholesale sale contract it had with the Company, with the termination effective as of November 30, 2003. The Avista Summer capacity, Deseret and Desert Power purchases all expired September 2003. The effect of removing these contracts increases net power costs by $8.7 million Total Company.

Water Year Adjustment

Q. Please explain the proposed adjustment.

A. Mr. Buckley rejects the Company's use of the Commission's longstanding 40-year rolling average hydro normalization methodology. In its place, he proposes to use only water years that are one standard deviation from the mean of available data. He cites two reasons for his proposal. First, he believes there is a tendency for regulated utilities to request rate relief when higher-than-expected actual power supply expenses occur due to unforeseen events. Second, two of the three electric utilities regulated by the Commission now have some form of power cost adjustment mechanism.

Q. Do you agree with the proposed adjustment?

A. No. The proposal has numerous flaws, and does not meet the Commission's requirement for adopting a new hydro normalization methodology. Nor are the underlying premises applicable in PacifiCorp's case. The Company has not filed for rate relief due to extreme hydro conditions. The Company also does not have a power cost adjustment mechanism, unlike Puget Sound Energy and Avista Utilities. I will discuss these and other flaws in his proposal below.

Q. Is the proposed change in hydro normalization methodology consistent with the Commission-ordered requirement for adoption of a new methodology?

A. No. In Puget Sound Power & Light Company's 1992 general rate proceeding, (Docket No. UE-921262), PacifiCorp and Avista both intervened due to the common issue involving the hydro normalization method. After considering testimony from all three utilities on this issue, the Commission adopted the rolling 40-year methodology and stated the following in its Eleventh Supplemental Order:

> "The Company is put on notice that this will remain the commission's position on this issue unless and until a clear and convincing argument supports a superior alternative."

Q Was a sound basis for the selection of a "one standard deviation" methodology discussed in Mr. Buckley's testimony?

A. No. Mr. Buckley refers to "extremes in power costs due to stream flow variations." However, no specific reason was discussed in his testimony. Use of his one standard deviation approach would exclude approximately one-third of a normal distribution. Mr. Buckley's proposed adjustment excluded 14 of the 40 years, which equates to 35 percent of all water years. This is the first time in my professional experience that someone has suggested that one-third of the items in a normal distribution are extreme. The selection of one standard deviation for his test of extreme conditions does not appear to be based on a known statistical principle.

Q. Does the proposed methodology produce results that are at odds with the 40-year rolling average method?

A. Yes. One of the reasons a rolling 40-year method was adopted is to use the most current data available. Mr. Buckley's method does not do this. For example, eight out of the 12 most current years in the 40 year average would be excluded by filtering the data using one standard deviation. This result is clearly in conflict with the Commission's adopted method.

Q. What method are Avista and Puget Sound Energy required to use?

A. Avista and PSE use the Commission-adopted 40 year rolling average normalization method, as prescribed in Docket No. UE-921262. Mr. Buckley's proposal would thus depart from the Commission's practice with respect to the other electric utilities it regulates.

Q. Does Mr. Buckley's proposal balance the interests of customers and stockholders?

A. Not at all. His proposal assumes that the Company would be protected from hydro conditions outside one standard deviation from the mean due to an ability to file for emergency relief in bad water years. As discussed below, this form of relief is likely not available to the Company in the event of poor hydro conditions. Nor is the other premise – a power cost adjustment mechanism – applicable in the case of the Company. Mr. Buckley's selection of one-standard deviation appears to be results driven, as the effect is to eliminate the poor hydro years from the modeling, without justification.

Q. Why do you dispute Mr. Buckley's assertion that the Company would be protected in poor hydro years because it could file for immediate relief?

A. Because of the diversity in the Company's generation portfolio, it is not clear that adverse hydro conditions alone would have sufficient impact to warrant emergency rate relief for the Company. Moreover, the Company's experience in Docket No. UE-020417 suggests that it would be very difficult to obtain emergency rate relief in Washington, given Staff's position in that proceeding that financial distress must be demonstrated on a Total Company basis, irrespective of the financial results on a Washington-only basis. Requesting deferred accounting could provide some relief on a prospective basis. However, hydro conditions are unpredictable, and the Company would have to experience poor conditions *before* it could file for recovery. Given the prohibition against retroactive ratemaking, the Company would not be able to recover the higher costs experienced before it filed for recovery. This is the approach that was available to the Company during the 2000/2001 Western energy crisis and the results were not satisfactory. In fact, the Company incurred over $270 million in excess net power costs system-wide during the energy crisis, before we realized the crisis was going to be more than a temporary price excursion. Therefore, the Company's ability to earn its authorized rate of return would be detrimentally impacted.

Q. Would controversies be reduced under Mr. Buckley's file for immediate relief scenario?

A. No. Based on my experience, there would likely be more controversy. As noted above, the Company and Staff disagreed in Docket No. UE-020417 as to whether the Company needed to demonstrate financial impact on a Washington or a Total Company basis. I also believe this approach would lead to a greater regulatory burden because it would likely result in more filings. Therefore, the very basis which Mr. Buckley states as his overriding justification for his proposal is flawed.

Q. Would his adjustment be appropriate if the Company had a power cost adjustment mechanism?

A. It could be, but since the Company does not have a power cost adjustment mechanism and Mr. Buckley has not proposed one, there is no basis for evaluating the reasonableness of his proposed adjustment. The proposed method should be considered only in the context of a comprehensive proposal that includes a power cost adjustment mechanism and that balances the interests of customers and shareholders.

Market Cap / Bridger Sales

Q. Please explain the proposed adjustment.

A. Mr. Buckley proposes to adjust the Company's Market Cap data series used in the GRID model during graveyard hours (1:00 A.M. to 5:00 A.M.) Pacific Prevailing Time, for the Mid-Columbia Market to impute additional wholesale sales from the Jim Bridger coal generation plant. He believes his adjustment is reasonable because he thinks Bridger has recently operated at a higher level. The proposed adjustment would decrease net power costs by $1.15 million on a Total Company basis.

Q. Please explain the Market Cap data series used in GRID.

A. The Market Cap data series is the means by which the degree of liquidity in the market for a particular transmission area is established in GRID. Four liquid markets are modeled in GRID: COB (California-Oregon Border), Mid-Columbia, DSW (desert southwest – Palo Verde and Four Corners) and SP15. For most hours the liquidity is set at an arbitrary, large number that indicates there is not an upper bound to the purchase/sales in that market. In reality, the size of the firm transfer rights (FTR) will limit the size of market, with the exception of graveyard hours. During the graveyard hours, there is too much excess base load capacity to have a liquid market where there is a willing buyer for a willing seller. To address this issue, the Company examined short-term transactions for five hours in each of the liquid markets. The Company used the average sell volume during the five hours to define the liquidity of the sale market. Without market caps, GRID would run thermal generation units at unrealistically high levels.

Q. How can you determine the appropriate level of generation for a coal plant?

A. The Company uses a rolling four year average of maintenance and forced outages to normalize coal generation. Therefore, a four year average of actual generation would produce the expected level for coal resources. However, this method may overstate the expected level of coal generation because maintenance is increasing at the plants due to the age of the units, as explained by Mr. Woolley.

Q. Is this adjustment affected by the proposed hydro adjustment?

A. Yes. If it were not for Mr. Buckley's proposed water year adjustment, this market cap adjustment would not have been considered. The proposed water year adjustment increases hydro generation by 140,000 MWh. This increase reduces the Company's need and ability to transfer energy to the West and causes the model to back down Bridger generation as a result of system constraints. Without the proposed water year adjustment, Bridger generation would be at a reasonable level.

Q. Please explain.

A. The historical average for Bridger generation for the 48 month periods ending March 2003 and March 2004 is 10,341,659 MWh and 10,049,000 MWh, respectively. In comparison, the Company's modeled Bridger generation is 10,408,198 MWh, which is higher than the four year average of historical generation and Mr. Buckley's proposed generation of 10,303,644 MWh. Given the high level of Bridger generation output already reflected in the model, there is no need for the further adjustment proposed by Mr. Buckley.

Prudence of New Resources

Q. Does the Company agree with Mr. Buckley that it is necessary to demonstrate the prudence of the Company's resource acquisitions on a Washington stand alone basis?

A. No. As explained in my direct testimony, it is appropriate to evaluate the prudence of new resources on a system-wide basis, given that the Company's system is operated on an integrated basis. Operation of the system on an integrated basis captures the efficiencies of the system, which benefits all customers by keeping net power costs as low as possible. Operating and planning the Company's system from the perspective of one state would lead to sub-optimal results and higher net power costs.

Q. Have any of the Company's Eastern Control Area resources been included in Washington rates previously?

A. Yes. Even before the Company's merger with Utah Power, the Company operated two control areas. The Wyodak and Dave Johnston coal generation facilities were and still are included in the Eastern Control Area. These resources were and still are included in Washington retail rates because they were determined to be necessary and useful for serving Washington customers. The Company was not required to make the type of showing demanded by Mr. Buckley before these resources could be included in retail rates. The Company's requested treatment for new resources in this case is consistent with the Commission's adopted treatment for resources located in the Eastern Control Area.

Q. Is the Company's IRP planning process consistent with the Commission's least cost planning rules?

A. Yes. The Company's IRP planning process is done on a system basis consistent with Washington least cost planning rules, which does not require planning to be done on a Washington basis. Although I understand Staff has recently taken the position that the Company should be required to conduct its IRP process on a Washington-only basis, that requirement is not imposed by the Commission's current rules nor has the Commission itself imposed that requirement on the Company. In fact, on the issue of state-by-state IRP analysis, the Commission's acknowledgement of the Company's most recent IRP stated the following:

> "PacifiCorp's analytical approach to the resource plan is based on system-wide optimization routine. While the benefits from a system-wide approach may allow extraction of opportunities that exist among regions serviced by the Company, state-specific policies may distort the optimal choices of resources. State specific policies that affect the selection of resources (e.g., wind, DSM, etc.), economic development (e.g., lower rates for industrial customers), inclusion of externality in planning process, etc., may force PacifiCorp to acquire higher cost resources. To determine the cost of state policies, the Company should optimize its resource portfolio assuming these policies are eliminated. State mandated policies could be applied a sensitivity analysis or scenario to the "optimal mix of resource" –to determine the additional costs." (October 6, 2003 letter from the Commission to Judith A. Johansen, CEO, p. 8)

Rather than requiring planning to be performed on a "state-specific" basis, the letter acknowledges that a system-wide approach allows the "extraction of opportunities that exist among regions serviced by the Company." As far as the comments regarding the impact of state-specific policies on the selection of resources, Staff does not appear to be taking the position that any of the resources under consideration in this case is the result of a state-specific policy that may have distorted the optimal resource choice.

Q. Apart from the Company's position that it is sufficient to demonstrate prudence on a system basis, has the Company demonstrated prudence on a Washington basis?

A. Yes. As shown on Mr. Duvall's Exhibit No.___(GND-8), load losses in both the Western and Eastern Control Area affect generation located in the Eastern Control Area. This evidence, along with my Exhibit No.___(MTW-5) in my direct testimony, showing Washington load growth since 1985 and resources acquired during that time, proves a need for new resources to serve Washington load. It also demonstrates that resources located in the Eastern Control Area do in fact serve Western Control Area retail loads and thereby provide benefits to Washington customers. The Joint Report also contains other evidence regarding the benefits to Washington customers from the additional resources throughout the Company's system.

Q. Is Mr. Buckley's proposal to use the Hybrid allocation method inconsistent with his testimony on prudence?

A. Yes. The Hybrid method used by Mr. Buckley uses the same GRID run as used by the Company with the exception of his adjustments. All of the loads and resources in the Eastern Control Area are included in net power cost relied upon by Mr. Buckley. A portion of the purchase power costs and wholesale sales revenues from the DSW market directly flow to Washington under the Hybrid method. These market transactions are dependent upon the resources that are modeled in GRID. Therefore, even under the Hybrid proposal, costs assigned to Washington customers are dependent upon the operation of plants in the Eastern Control Area. The operation of the plants in the Eastern Control Area also affects the volume of interchange transferred between control areas, and therefore affects the costs assigned to Washington customers. For example, the Company has transfer capability between control areas from East to West on the AMPS line and west of Bridger when Bridger is not at full capacity. Any transfer of power is system power from the Eastern Control Area and is not specified as being from any one plant. Anytime there that there are transfers from the Eastern Control Area to the Western Control Area, then any plant in the Eastern Control Area that is producing power at that time is used and useful for serving Washington customers. For these reasons and the reasons discussed above, the Commission has a basis for finding that the resources are prudent and are eligible to be included in Washington rates.

Staff and ICNU Adjustments for Financial Hedges

Q. Please explain the proposed adjustments.

A. ICNU witness Falkenberg proposes to remove the premium cost of the Aquila hydro hedge and the J. Aron and Morgan Stanley temperature hedges from proposed net power costs. He believes the proposal is reasonable because only the premium costs for these financial hedges are included in GRID and there is no way that the benefit can be factored into the ratemaking process. This proposed adjustment would reduce the

Company's net power costs by $1.75 million for Aquila, $2.1 million for J. Aron and $1.8 million for Morgan Stanley on a Total Company basis. Staff witness Buckley proposes a similar adjustment for the Aquila and Morgan Stanley financial hedges based on similar grounds.

Q. Do you agree with the proposed adjustment?

A. No. These contracts were prudently executed risk mitigation measures undertaken to protect the Company and its customers. Since customers benefit from the risk mitigation, the premium costs as well as the benefits should be passed through to customers.

Q. Is there any distinction between these financial hedge contracts and the Sempra and Morgan Stanley call contracts, discussed later in your testimony?

A. Yes. These particular contracts are financial hedges so there is no energy benefit included in GRID. The Sempra and Morgan Stanley call contracts provide physical energy so there is a benefit included in GRID. Further, hedge settlements (either payments or receipts) are not known and measurable on a going forward basis, so they should not be built into ongoing retail rates.

Q. Do you agree that there is no way that the benefits of these contracts can be factored into the ratemaking process?

A. No. In my direct testimony I proposed to include the costs and benefits of these contracts in a balancing account so they can be passed to customers. Mr. Griffith's direct testimony discusses how the schedule 96 balancing account would operate.

Q. Did the Company receive benefits from these contracts during the test period?

A. Yes. The Company received a $5.2 million Total Company payment for the Aquila hydro hedge as a result of poor hydro conditions. Washington's share of that payment would be included in Schedule 96 and returned to customers.

Q. How do you respond to the assumption stated by Mr. Falkenberg that the Company is not concerned about cost recovery?

A. The assumption is incorrect. The Company is very concerned about getting recovery of its costs.

Q. Please summarize your recommendation for the Commission.

A. The Company has prudently chosen a risk mitigation strategy to protect the Company and customers that includes limiting exposure to hydro and temperature volatility. The premium costs and benefits received from these financial hedges should be collected in a Schedule 96 balancing account and passed through to customers.

ICNU Witness Falkenberg's Adjustments

<u>Overall Net Power Costs</u>

Q. Is Mr. Falkenberg's assertion that the Company's net power costs have continued to decline since the power crisis true and is his $500 million overall net power cost recommendation reasonable?

A. No. Actual net power costs for 2003 were approximately $598 million. Actual net power costs for the twelve month period ending May 2004 are approximately $687 million. Forecast net power costs for Fiscal Year 2006 are expected to be in excess of $745 million. So it is quite apparent that net power costs are not declining as suggested by Mr. Falkenberg and that his $500 million overall net power cost recommendation is unreasonably low.

<u>BPA Settlement Adjustment</u>

Q. Please explain the proposed adjustment.

A. Mr. Falkenberg proposes to include 41,600 MWh of short-term firm energy received in July and August 2003 and 21,600 MWh received in September 2003 from BPA at zero cost, as a settlement for energy mistakenly delivered to BPA from November 16, 2000 through April 4, 2001 because of a faulty BPA meter. Mr. Falkenberg believes his adjustment is reasonable because: 1) the Company never requested direct recovery of excess net power costs in Washington, 2) even in states that allowed recovery of excess power costs, the level of recovery is far less than actual, 3) he believes the Commission's reopening of the rate plan only benefits the Company, and 4) he believes that the Company includes one-time items in its calculation of power costs in Washington while it did not do so in Wyoming. The proposed adjustment would reduce net power costs by $6.86 million Total Company.

Q. Do you agree with Mr. Falkenberg's proposed adjustment?

A. No. As I will explain below Mr. Falkenberg's analysis is flawed at numerous levels and should be rejected.

Q. Would adoption of Mr. Falkenberg's proposed adjustment be consistent with accepted regulatory principles?

A. No. The free energy received from BPA was a one time settlement related to an inadvertent Company delivery of energy to BPA prior to April 5, 2001 and will not recur. Consistent with accepted ratemaking practice, prior period and or non-recurring items are generally excluded from base rates because they do not provide a proper match between costs and benefits and will not impact ongoing operations. In fact, recovery of a prior period item generally constitutes retroactive ratemaking which is prohibited, without deferred accounting authorization. In instances where a one time item provides an ongoing benefit, it could be reasonable to include the costs in base rates. The BPA settlement does not produce ongoing benefits, however.

Q. Did the Wyoming Commission include the BPA settlement energy in net power costs in the Company's most recent general rate case?

A. No. The Company received the same treatment in Wyoming that the Company is seeking in Washington (*i.e.*, the exclusion of the free BPA settlement energy from net power costs). It should be noted that Wyoming is most like Washington, because in neither state did the Company recover any of its excess net power costs related to the Western energy crisis. In contrast, the Company deferred approximately $347 million including carrying charges to be recovered from jurisdictions other than Washington, Wyoming, and California.

Q. Do the underlying circumstances related to the energy crisis justify inclusion of the BPA settlement energy in Washington?

A. No. While the underlying circumstances are different, the most significant fact of all is identical, that the Company's shareholders paid for all of the excess net power costs incurred to serve Washington customers during the energy crisis.

Q. Do you agree with Mr. Falkenberg's suggestion that Washington customers are paying for the power crisis through the Commission's decision to re-open the rate plan?

A. Absolutely not. The excess net power costs incurred during the energy crisis will never be recovered from Washington customers. An important point that Mr. Frankenberg omitted is that customers are expected to benefit from breaking the rate plan since the Commission determined it was no longer in the public interest for the Company's rates to remain unexamined through the rate plan period. Given that the Company will never recover any of its excess power costs incurred during the Western energy crisis, inclusion of the free BPA settlement energy would not be equitable.

Q. Is Mr. Falkenberg accurate when he states "unlike the current practice in Wyoming, the Company does not exclude one-time items from its calculation of power costs in Washington"?

A. No. He is attempting to distinguish the treatment we received in Wyoming – where the BPA settlement energy was *not* included – by claiming that all such one-time items are excluded in Wyoming. In fact, however, all other one-time items referred to by Mr. Falkenberg in footnote 6, page 13 of his testimony were included in Wyoming. Exhibit No. ___(MTW-8), which is a copy of our Wyoming authorized NPC, shows the inclusion of the referenced contracts. Thus the "current practice" of the jurisdictions are not different, and it is significant that the BPA settlement energy was excluded in Wyoming – the same treatment we are seeking here.

Long-Term Contract Adjustments

Q. Will you be addressing Mr. Falkenberg's criticism of the Company's use of Black Scholes modeling in the economic analysis of various contracts?

A. No. Mr. Mumm will be addressing Black Scholes modeling issues. I will address the various contract adjustments from the perspective of net power cost modeling and reasonableness.

Q. Do you have any general comments regarding the Company's use of hedge contracts?

A. Yes. Throughout the Western energy crisis, one of the messages the Company repeatedly heard from various regulators and intervenors was that the Company should do more hedging to mitigate risk from the volatile wholesale market and other variables, to protect both the Company and customers. In response to those suggestions, the Company entered several hedge contracts to reduce our net power cost exposure. Yet in this case, Mr. Falkenberg has proposed to eliminate a significant portion of the hedge costs included in the Company's case. Adoption of this recommendation would, in the Company's view, set a bad precedent and would discourage use of a valuable tool that protects both customers and stockholders from net power cost volatility. In addition, for the reasons discussed below with respect to the individual contracts, Mr. Falkenberg is not correct when he claims that benefits ascribed to resources by Black-Scholes modeling can not be captured in ratemaking.

West Valley CTs

Q. Please explain the proposed West Valley adjustment.

A. Mr. Falkenberg proposes to make an adjustment to include option value for the West Valley peakers. The proposed adjustment would reduce net power costs by $3.1 million Total Company.

Q. Was the acquisition of West Valley analyzed from an economic and risk mitigation basis?

A. Yes. West Valley was analyzed as part of an RFP process to secure resources to meet load requirements. Through that process it was determined to be one of the least cost options on a risk adjusted basis and was acquired.

Q. Please explain the value associated with West Valley.

A. West Valley provides intrinsic and extrinsic value. Intrinsic value is the value that is derived from the dispatch of the unit during normal conditions. Extrinsic or option value is the value that a resource with optionality can capture related to volatility in the market. For example, if the market price of electricity spikes while the price of gas does not, the spark spread for a gas fired unit increases and it is more economic to run. Units such as West Valley can capture this value or provide risk mitigation by providing generation to meet retail load requirements or by making sales in the wholesale market, if they are not already being fully dispatched.

Q. Is the option value captured in GRID and the Company's proposed net power costs?

A. Yes. The option value allows the Company to avoid higher priced market purchases, serve load when transmission constraints exist, or make additional wholesale sales. For example, if the spark spread for gas and electricity increased because electric prices increased and gas prices did not increase in the same amount, the Company would run West Valley at a higher capacity factor so higher cost market purchases could be avoided or so additional wholesale sales could be made. Since the Company's proposed net power costs include actual executed short term firm (STF) transactions exclusive of the one-time BPA settlement, for the period April 2003 through September 29, 2004, sales made or purchases avoided as a result of the option value of West Valley are captured in GRID, contrary to Mr. Falkenberg's suggestion. This option value is captured in GRID because the actual executed transactions cover the summer peak period, the period with the most volatility and option value in the DSW. Likewise, the optionality of the Morgan Stanley and Sempra call contracts is captured in GRID because they are seasonal contracts that operate June 1, 2004 through September 30, 2004, as discussed further below.

Q. Do the Company's other resources include optionality?

A. Yes. Many of the Company's resources include some degree of optionality, which means they may provide more or less value than is included in retail rates that are based on normalized results. For example, coal resources, gas resources other than West Valley, hydro resources and several wholesale sales and purchase power contracts include some optionality. Current regulation, however, does not impute any additional option value for these resources. Rather, they are included in rates based on normalized results.

Q. Do you agree with the proposed adjustment?

A. No. The option value is reflected in GRID and the proposed adjustment is not consistent with the manner in which the Company is currently regulated whereby rates are set based on normalized results. The proposed adjustment is contrary to that principle, and attempts to capture potential value between rate cases that is not known and measurable. It should be rejected.

Q. Has this treatment of West Valley ever been litigated?

A. Yes. Mr. Frankenberg proposed this same adjustment in the Company's last Wyoming general rate case. In that case, the Commission rejected Mr. Falkenberg's proposed adjustment.

<u>Sempra Call</u>

Q. Please explain the proposed adjustment for the Sempra contract.

A. Mr. Falkenberg proposes to remove the contract from net power costs because he does not believe the full benefits of the option contract are or can be reflected in the GRID model. The adjustment reduces net power costs by $.86 million Total Company.

Q. Please explain the contract.

A. The Sempra contract is a 100 MW summer peak capacity contract with an option (call) to take firm energy on a day-ahead basis, at a strike price equal to a set heat rate times a daily Malin Midpoint gas index plus $.04 per MMBtu. The contract provides reliability, risk mitigation, and the ability to serve peak load requirements during the summer season.

Q. Do you agree with the proposed adjustment?

A. No. There are several reasons the adjustment should be rejected by the Commission. First, Mr. Falkenberg's statement that GRID cannot or does not fully reflect the benefits of the contract is incorrect. As I mentioned above, the option value is captured in GRID because the Company includes actual executed STF transactions, including any sales made as a result of the energy called upon through the SEMPRA contract. Second, the GRID dispatch of the contract is very similar to actual dispatch. GRID dispatches Sempra for 68,800 MWh compared to the actual test period dispatch of 70,400 MWh, thereby capturing the option value of the contract. Third, Mr. Falkenberg fails to recognize the value of reliability provided by the Company's right to take energy. The value of the right to take energy is much like a life insurance policy that provides protection in the event of an untimely event. Just because there is not a payout for a policy for a given year, does not mean a benefit was not provided. In fact, the benefit provided was that the beneficiary was protected from the impact of an untimely event. The same principle is true for the Sempra contract in that it provides system reliability and risk mitigation through the right to take energy at the Company's discretion and customers should pay for that benefit. Finally, the contract was selected through an RFP process, where the economic analysis indicated that it was a least cost option for the Company on a risk-adjusted basis.

Q. Has this treatment of the Sempra contract ever been litigated?

A. Yes. Mr. Falkenberg proposed this same adjustment in the Company's last Wyoming general rate case. In that case, the Wyoming Commission rejected Mr. Falkenberg's proposed adjustment.

Morgan Stanley Call

Q. Please explain Mr. Falkenberg's proposed adjustment for the Morgan Stanley contract.

A. The proposed adjustment reduces the cost of the contract by $2.4 million Total Company basis. Mr. Falkenberg does not believe the full benefits of the contract are reflected in GRID.

Q. Please explain the contract.

A. The Morgan Stanley contract is a 100 MW summer peak capacity contract with an option (call) to take firm energy on a day-ahead basis at a strike price of $55 per MWh. The contract provides reliability, risk mitigation, and the ability to serve peak load requirements during the summer season.

Q. Do you agree with the proposed adjustment?

A. No. The contract is very similar to the Sempra contract, which also benefits customers. In fact, the dispatch of the Morgan Stanley contract on a normalized basis is greater than the actual dispatch. GRID dispatched the contract for 156,800 MWh compared to the actual dispatch of 80,000 MWh, so GRID is capturing almost twice as much option value as was captured on an actual basis. For this reason and the additional reasons discussed with respect to the proposed Sempra adjustment, this adjustment should also be rejected.

Q. Has this treatment of the Morgan Stanley call contract ever been litigated?

A. Yes. Mr. Falkenberg proposed this same adjustment in the Company's last Wyoming general rate case. In that case, the Wyoming Commission rejected Mr. Falkenberg's proposed adjustment.

P4 Contract

Q. Please explain the proposed adjustment for the P4 contract.

A. Mr. Falkenberg proposes to reduce the cost of the P4 contract because he believes the system integrity components of the contract cannot be captured in GRID. The proposed adjustment would reduce the Company's revenue requirement by approximately $.49 million Total Company.

Q. Do you agree with the proposed adjustment?

A. No. The system integrity component is just a small portion of the overall contract that provides approximately $11.0 million of benefits to customers.

Q. Is it correct that the system integrity portion of the contract is not captured in GRID?

A. Yes. However, that does not justify excluding the cost of $40,500 per month from proposed net power costs. The system integrity component provides system reliability and risk mitigation by allowing the Company to interrupt P4's operation in the event of a system emergency, much like a life insurance policy provides protection as discussed above. While we do not expect to incur a system emergency under normal conditions, customers are still protected from system emergencies and should pay for the cost of that protection.

Q. Is it reasonable to exclude a portion of the contract as proposed by Mr. Falkenberg?

A. No. The entire contract is a package and that package produces approximately $11.0 million of benefits for customers. It is not reasonable to assume the same level of benefits would exist for a contract that is different than the original contract.

Q. Has this treatment of the P4 contract ever been litigated?

A. Yes. The issue was raised by Mr. Falkenberg in the Company's last Wyoming general rate case and was rejected by the Wyoming Commission. The contract was also reviewed and approved by the Idaho Commission.

Fort James Contract

Q. Please explain the proposed adjustment for the modeling of the Fort James Cogeneration Project.

A. Mr. Falkenberg proposes to reduce the generation purchased from the Fort James Cogeneration Project because he believes the Company has overstated the generation. The adjustment would reduce the Company's original filed net power costs by $34,105 on a Washington basis.

Q. Does the Company agree with this proposed adjustment?

A. Yes. The adjustment is reasonable.

Wyodak Capacity

Q. Please explain the proposed adjustment.

A. Mr. Falkenberg proposes to remove the seasonal capacity rating used in GRID for Wyodak modeling. The proposed adjustment would reduce net power costs by $1.8 million Total Company.

Q. Do you agree with Mr. Falkenberg's assertion that Wyodak capacity should be adjusted?

A. Yes. However, the impact of the adjustment should be $1.6 million Total Company rather than the higher figure proposed by Mr. Falkenberg. The original adjustment was based on anecdotal evidence from Company personnel. The Company's Generation Engineering Department recently completed a study which correlated Wyodak's monthly generation with Gillette, Wyoming's average monthly temperature to measure normal expected generation. Results of the study show that capacity ranges seasonally from 267-280 MW. Inclusion of the updated capacity values in GRID increases generation by approximately 81,000 MWh to 2.27 million MWh and would reduce net power costs by $1.6 million Total Company. A summary of the capacity analysis is shown below in Table 1.

Table 1 – Wyodak Unit 1 - Capacity

	Average Max Temperature F	Net Unit Output MW	Capacity MW
January	31.6	349	279
February	37.2	350	280
March	43.1	350	280
April	54.3	349	279
May	64.7	346	277
June	75.1	342	274
July	85	334	267
August	83.7	335	268
September	72.6	342	274
October	60.6	347	278
November	44.1	350	280
December	35	350	280

Q. What is your recommendation for this adjustment?

A. The Company's analysis is superior to Mr. Falkenberg's since it is seasonalized through the temperature correlation analysis. This is an important refinement given that Wyodak is an air cooled unit. The Company's $1.6 million figure should be adopted by the Commission.

Market Size Limit

Q. Please explain Mr. Falkenberg's proposed market size limit adjustment.

A. The proposed adjustment revises the Company's market caps during graveyard hours (1:00 – 5:00 AM) Pacific Prevailing Time (rather than the Low Load Hours as stated in his testimony) to allow more system balancing sales, which allow the Company's coal generation to produce more energy. According to Mr. Falkenberg, his adjustment is warranted because he believes GRID is backing too many units down to minimums during graveyard hours. The proposed adjustment would reduce the Company's original filed NPC by $9.9 million on a Total Company basis.

Q. What is the purpose of Market Caps?

A. Market Caps are used to limit the size of the market during graveyard hours to a realistic size, because the market is not completely liquid in the middle of the night. Without the caps, GRID would allow the coal units to generate more than they actually do.

Q. Do you agree with the proposed adjustment?

A. No. As I will demonstrate below, the Company's modeling of thermal plant generation is generous and Mr. Falkenberg's proposed modeling produces an excessive level of generation.

Q. Please explain.

A. The best indicator of whether GRID is producing a reasonable level of coal generation is the total level of coal generation, not the level of generation during only graveyard hours. As shown in Table 2 below, the level of coal generation proposed by Mr.

Falkenberg is approximately 45.3 million MWh and exceeds by a considerable amount – approximately 1.2 million MWh – the rolling four-year average for the 48 month period ended March 2003. If the actual average is updated to 48 months ended March 2004, his recommendation exceeds the average by 1.4 million MWh. On the other hand, the 44.4 million MWh of coal generation included in the Company's proposed net power costs is more consistent with historical coal generation. In fact, the Company's proposed level of coal generation is generous because it exceeds the four-year average by approximately 140,000 MWh.

Table 2 – Coal Generation

	Actual 48 Months Ending. MWh	Company Modeled MWh	Falkenberg Proposed MWh
Mar-01	44,242,679		
Mar-02	44,229,164		
Mar-03	44,067,179	44,382,407	45,269,008
Mar-04	43,914,808		

Q. Have you reviewed Mr. Falkenberg's Exhibit No. ___ (RJF-10) to determine the reasonableness of his generation normalization adjustments which he uses to justify his overall level of coal generation?

A Yes. There are several flaws in his analysis which render it useless.

1) As explained above, he failed to include a thermal generation reduction because of the Company's inability to carry operating reserves on the Swift Unit 1 hydro generation facility. The impact of this error is a reduction in thermal generation of 49,303 MWh.

2) The information used by Mr. Falkenberg is a little stale because he uses a four

year average ended December 2002. If the data is updated to a rolling four-year average ended March 2003 or March 2004, the average coal generation would be 44.1 million or 43.9 million MWh respectively, compared to Mr. Falkenberg's 45.3 million MWh.

3) The spinning reserve adjustment is understated slightly using a 48 month period ending March 2003 and overstated by approximately 94,000 MWh for the 48 month period ending March 2004.

4) As I will explain below and as Mr. Woolley explains in his rebuttal testimony, the outage adjustments recommended by Mr. Falkenberg are not reasonable and should be rejected.

5) It was wrong to assume that other base load coal generation units had unused generation which picked up the portion of Centralia generation not covered by the TransAlta purchase. Low cost base load coal generation units are run at their maximum dependable capacity (MDC) at all times unless there are system constraints, market liquidity problems or operational issues that prevent them from operating at their MDC. Additional capacity is therefore not available, contrary to Mr. Falkenberg's suggestion.

6) The Colstrip 3 adjustment is too small because it assumes that Colstrip 3 generation is one-half of the total Colstrip generation. 7) Using the more current four-year rolling average ending March 2004 excludes the older 1999 data used in Exhibit RJF-10 and shows an ever lower level of generation. Since more current information is a better representation of the Company's operation,

the 1999 market price adjustment should be excluded.

8) A review of the historical data shows that coal generation during 2000 was significantly higher than the other years, most likely due to the extremely high market prices and generation shortages during the Western energy crisis. This suggests that the generation was abnormally high and that it would be appropriate to make an adjustment to reduce coal generation for 2000, which would produce a lower level of generation.

Q. Have you corrected Mr. Falkenberg's Exhibit No. ___ (RJF-10)?

A. Yes. Exhibit No. ___ (MTW-9) is a corrected version of that exhibit which includes Mr. Falkenberg's original analysis and the corrected information for the 48 month periods ended March 2003 and March 2004. The exhibit demonstrates that the Company's modeled coal generation is reasonable and Mr. Falkenberg's is unjustifiably excessive. Mr. Falkenberg's adjustment should therefore be rejected by the Commission.

<u>Thermal Deration Factors</u>

Q. Which of Mr. Falkenberg's proposed thermal deration adjustments will you be addressing?

A. I will address the Hunter 1 outage, CT outage rates, Blundell deration, DJ 3 catastrophic outage, Hayden 1 catastrophic outage and the Colstrip 4 catastrophic outage. Mr. Woolley will also address the Hunter 1 outage, and other outages, in his rebuttal testimony.

Q. Please explain the Company's thermal outage rate methodology.

A. For at least the last 10 years, the Company's methodology has consisted of a four-year rolling average method based on actual historical information without adjustments, with only a few exceptions related to the Hunter 1 outage. This method allows for a four-year amortization of outages that reduces variations in net power costs from year-to-year to smooth the customer impact. This method has been accepted in all of the Company's jurisdictions except Idaho and Washington, which have not had fully litigated cases for almost 18 years.

<u>Hunter 1 Outage</u>

Q. Please explain the proposed Hunter 1 outage adjustment.

A. Mr. Falkenberg proposes to remove the Hunter 1 outage from the Company's four-year rolling average outage rate calculation as a catastrophic one-time event and one whose prudence has not been established. The proposed adjustment would reduce the Company's net power costs by $7.7 million Total Company.

Q. Do you agree with the proposed adjustment?

A. No. The adjustment proposed by Mr. Falkenberg is inconsistent with his recommendation in Wyoming Docket 20000-ER-02-184. Moreover, his adjustment fails to take into account that the Company has been provided some recovery for the Hunter outage in Oregon, Idaho, California, and Utah.

Q. Is Mr. Falkenberg's statement that the Company's modeling assumed that the Hunter 1 outage would recur once every four years an accurate representation?

A. No. The Company's outage rate modeling is simply a four-year amortization of outage costs. As observed by Mr. Falkenberg in testimony in Wyoming, the Company's method is a balanced and beneficial method because it creates an incentive for the Company to keep the duration and cost of the outages as low as possible.

Q. How do you respond to Mr. Falkenberg's statement on page 35 of his testimony that the Company has provided inadequate justification for seeking recovery of Hunter 1 costs in Washington?

A. The facts do not support his position. First, the Company received partial recovery of the Hunter 1 replacement costs in Oregon, Idaho and Utah in dockets specifically related to the energy crisis. The idea was that customers would bear a portion of the costs, as would stockholders. Since cost recovery had been dealt with in other dockets, there would be no basis for including the Hunter 1 outage in future general rate cases in those jurisdictions. Absent the Hunter 1 adjustment, the outage rate methodology employed in Oregon, Idaho and Utah is the same as is proposed in this case. Second, the Company's Washington situation is very similar to Wyoming, in that no separate recovery was allowed for Hunter outage costs. However, in the Wyoming proceeding Mr. Falkenberg took a position on behalf of his client, the Wyoming Industrial Energy Consumers (WIEC), that is completely different from his proposal in this case.

Q. Please explain.

A. In Wyoming Docket No. 20000-ER-02-184, Mr. Falkenberg offered two outage rate options for the commission to consider. Option 1 was predicated on Hunter 1 outage costs being addressed as part of the recovery of extraordinary power costs associated with the Western energy crisis. Under this option, he proposed to make adjustments to remove outages that he considered to be abnormal or non-recurring. Option 2, which was supported by WIEC, was predicated on Hunter 1 being addressed in the general rate case portion of the docket. In this option, he proposed that all outages be included in the Company's four-year rolling average method with no adjustments. Ultimately, the Wyoming Commission adopted Option 2. It is important to note the similarity between the Washington and Wyoming circumstances. In both jurisdictions, the Company did not recover any of the extraordinary power costs attributable to the Western energy crisis and the Hunter outage from customers. In Wyoming, the Company's recovery of Hunter 1 outage costs was limited to the outage rate calculation in the general rate case. In Washington, the Company's only avenue for recovering a portion of those costs is through the general rate case process. As such, the Company is requesting the same treatment that was adopted in Wyoming.

Q. Has Mr. Falkenberg previously provided testimony that was supportive of the Company's outage rate methodology?

A. Yes. In Wyoming Docket No. 20000-ER-02-184, he supported the Company's methodology of using the four years of outage experience, unadjusted, as the basis for setting rates. In that docket he testified that:

> "This procedure effectively allowed for a four-year amortization of major outages. While it did not provide an exact matching between actual outage costs and subsequent recovery, it was a balanced and beneficial approach. It afforded the opportunity to reflect outages cost impacts in customer rates, while

> at the same time creating an incentive for PacifiCorp to minimize the cost and duration of all outages."

Q. If allowed to keep the Hunter 1 outage in its outage rate calculation, will the Company be fully compensated for the replacement power costs it previously incurred?

A. No. The Company would recover only a fraction of the replacement power cost because the market price of energy is significantly lower now than it was during the energy crisis. During the Company's Wyoming case we estimated the Total Company impact of replacement energy for the outage was $270 million. In this case, Mr. Falkenberg estimated the net power cost impact of the outage to be $7.7 million. Over a four year period that would produce approximately $31 million Total Company or a mere 11.5 percent of replacement power costs incurred.

Q. Does the four-year average method produce reasonable results?

A. As I explained above, the results are reasonable as long as adjustments are not made to the historical outage data. In this case the Commission should reject Mr. Falkenberg's proposed adjustment. However, if the Commission decides it is appropriate to make adjustments to remove historical outages, the four-year method would produce results that are not representative of expected operations, given the aging of the Company's plants and the higher maintenance requirements discussed by Mr. Woolley. As shown in Table 2, the Company's thermal generation has declined over the last three fiscal years. In this situation, the Commission should adopt a method that utilizes the most recent twelve month period of maintenance and outage rates as being most representative of expected operations. The impact of this method would increase net power costs by $1.7 million.

CT Outage Rates

Q. Please explain the proposed CT outage rate adjustment.

A. Mr. Falkenberg proposes to use the mature outage rates for the Gadsby and West Valley CTs instead of using the actual normalized outage rates proposed by the Company. The proposed adjustment would reduce the Company's net power costs by $.7 million Total Company.

Q. Please explain how the Company modeled the CT outage rates?

A. The Company used the actual historical outage rates incurred since the units were placed in service, plus assumed mature outage rates for the remainder of the four–year period because the units have not been in operation for four years. The impact of the Company's modeling was to reduce the outage rates below actual historical operation.

Q. Do you agree with the proposed adjustment?

A. No. As I explained above, the Company's methodology does not assume that the initial operation outages will occur once every four years. Rather, it amortizes historical outages over a four-year period to smooth the net power cost impact on customers. In addition, the Company's operation of these plants compares favorably with industry statistics. The Company's average actual forced outage rate for these units was 17.79 percent through March 2003, while industry data for the period 1999 through 2002 was 18.61 percent. Thus, the Company's performance has been better than the industry average and the performance of these units has continued to improve. The average actual outage rates through March 2004 was 11.61 percent, and the Company modeled outages at a still lower rate of 8.58 percent. The outages are not extraordinary, as suggested by Mr. Falkenberg, but are in fact reasonable and therefore the proposed adjustment should be rejected by the Commission.

Q. Are there other alternatives for the Commission to consider?

A. Yes. As I suggested above, if it is not appropriate to amortize actual outages over a four-year period, the Commission should adopt an approach where outage rates are based on the most recent 12 months of data at the time of the filing.

<u>Blundell Deration</u>

Q. Please explain the proposed adjustment.

A. Mr. Falkenberg proposes to remove the portion of a Blundell geothermal plant outage that occurred from October 1998 to May 2001 that is included in the Company's GRID modeled outage rates. He believes the adjustment is reasonable because he believes the Company's modeling assumes the problem was never solved and will continue to occur. The proposed adjustment would reduce net power costs by $.07 million Total Company.

Q. Do you agree with the proposed adjustment?

A. No. As stated previously in my testimony, the Company's outage rate modeling amortizes the outages over a four-year period to smooth the net power cost impacts for customers. The method does not assume the outages will recur. The proposed adjustment should be rejected.

DJ 3, Hayden 1 and Colstrip 4 Catastrophic Outages

Q. Please explain the proposed adjustment.

A. Mr. Falkenberg proposes to remove these outages from the modeled outage rates included in GRID. He believes the adjustment is reasonable because the Company identified these outages as catastrophic in Oregon Docket UE 134 and proposed a normalizing adjustment to remove a portion of the outages. The proposed adjustments would reduce the Company's net power costs by $2.0 million Total Company.

Q. Does Mr. Falkenberg provide sound reasoning for his adjustment?

A. No. While it is true that the Company proposed those adjustments in UE 134, that methodology was abandoned because the Company it was not consistent with the four-year rolling average method. In fact, the UE 134 methodology was not used in the Company's last round of general rate cases in Oregon and Wyoming and the adjustments were not proposed by any of the parties, including Mr. Falkenberg. So Mr. Falkenberg's reasoning is illogical and his adjustment should be rejected by the Commission.

CT Dispatch Logic / Quick Start

Q. Please explain the proposed commitment logic adjustment.

A. Mr. Falkenberg proposes to impute $1.0 million of quick-start benefits since the version of the GRID model used in this case does not calculate that benefit. He also proposes to lower net power costs by an additional $.27 million to remove what he considers to be illogical generation through a redispatch of the CTs outside of the GRID model.

Q. Do you agree with the proposed adjustment?

A. I agree with the proposed imputation for quick start benefits. I do not agree with the remainder of the adjustment.

Q. Please explain the remainder of his adjustment.

A. For the eleven gas units that cycle, Mr. Falkenberg compared the fuel cost with the market value of the generation during light load hours. In a few months, the market value is lower than the fuel cost. From this observation he concluded that the CT unit dispatch is illogical.

Q. Do you agree with his assertion that the CT unit dispatch is illogical?

A. No. Mr. Falkenberg's analysis is flawed in that it fails to consider the opportunity cost of the lower cost units. For example, if West Valley #5 (with a cost of $45/MWh) holds reserves instead of Cholla (with a cost of $14/MWh), the Company has the opportunity to make an extra $31/MWh for each MWh of reserve allocation that is released from Cholla. If a credit for releasing reserves is applied to Mr. Falkenberg's analysis, all the months in his work papers are profitable.

Exhibit No. ___(MTW-10) replicates Mr. Falkenberg's work papers regarding this adjustment with one additional factor. It applies a reserve credit to the fuel cost, which reflects the opportunity costs associated with the reserves. The exhibit examines the fuel cost of the generation, market value of the generation, and allocated reserves. As in Mr. Falkenberg's work papers, the exhibit looks at the light load hours for eleven gas units. The reserve credit is based on Cholla's opportunity cost relative to the eleven units and the unit's allocated reserves. The opportunity cost is applied to the allocated reserves. The exhibit shows that the units have a positive net market value in all months, which demonstrates that there is no basis for Mr. Falkenberg's adjustment.

Q. Cholla has a reserve carrying capability of 40 MW. The West Valley units, by themselves, can carry more that that. What is the effect of using Cholla for purposes of your reserve credit calculations?

A. The use of Cholla would understate the value of the reserve credit. Cholla, the highest cost coal unit, was used to simplify the example. Cholla is just one of many coal units that are capable of holding reserves. All of the other coal units have a lower incremental cost. Reserves are allocated from the highest cost unit to lowest cost unit. When a gas unit is allocated reserve, it is freeing the lowest cost unit to generate. If we examined each of the 3,856 light load hours for each of the eleven gas units to determine which coal unit was freed to generate more, the reserve credit would be larger.

Q. What is your recommendation for this adjustment?

A. The Commission should reduce the Company's proposed net power costs by $1.0 million on a Total Company basis to capture quick-start benefits of the CTs. The balance of the adjustment is incorrect, however, and should be rejected.

<u>Emergency Energy Dispatch</u>

Q. Is the proposed adjus tment included in the Company's modeling corrections discussed above?

A. Yes. It was the only modeling correction adjustment adopted by Mr. Falkenberg. It has already been incorporated into the Company's updated net power costs. Therefore, no further adjustment is necessary.

Gadsby / West Valley Heat Rates

Q. Please explain the proposed heat rate modeling adjustment.

A. Mr. Falkenberg believes the Company's modeling substantially overstates the heat rates compared to actual heat rates shown in the Company's 2002 FERC Form 1. The proposed adjustment would reduce the Company's originally filed net power costs by $3.19 million Total Company.

Q. Do you agree with his assessment of the heat rates for the CTs and the Gadsby Steam plant?

A. No. Mr. Falkenberg's analysis is flawed. First, the heat rates for these plants are consistent with the level of operating reserves that are being carried on the units in GRID. In order for the units to be dispatched at the heat rates proposed by Mr. Falkenberg, the units would have to be run at a higher capacity factor. When dispatched at a higher capacity factor these units would not be able to carry the same amount of operating reserves that are being carried in GRID and other lower cost thermal units would be required to carry those reserves. This would actually result in a higher level of net power costs than the Company is proposing. Second, his proposed adjustment was calculated by a simple spreadsheet outside the model as opposed to dynamically allowing the model to dispatch the plants based on the heat rates in the model. This raises serious concerns over the results of his analysis because the dynamic operation of the units is not captured. In fact, this is the reason his proposed adjustment reduces net power costs when it would actually increase net power costs, as I explained above.

Q. How were the heat rates for the Gadsby and West Valley peakers developed?

A. Gadsby Units 4-5-6 and West Valley Units 1-2-3-4-5 heat rate curves were developed based on data from the manufacturer, General Electric (GE). GE provided tables of data estimating performance of the combustion turbine - generator sets for various ambient temperatures. The heat rate data provided by GE was based on electrical output at the generator terminals and the lower heating value of natural gas. PacifiCorp used the data provided by GE to estimate the net unit heat rates based on delivery of electricity to the high side of the generator step-up transformers and the higher heating value of natural gas.

Q. Has the Company reviewed the performance of the CT units based on actual operation?

A. Yes. The Gadsby heat rate at maximum availability was consistent with the level originally projected. The West Valley heat rate at maximum availability, however, was 5 percent lower than projected.

Q. Did the Company update the West Valley heat rates?

A. Yes. The lower actual heat rate was included in the Company's modeling corrections discussed above. The Company's correction reduced net power costs by $1.57 million so no further adjustment is necessary for West Valley.

Q. Has this issue been litigated in any of the Company's recent general rate cases?

A. Yes. The same issue was raised by Mr. Falkenberg in the Company's last Wyoming general rate case (Docket No. 20000-ER-03-198) and his proposed adjustment was rejected by the Wyoming Commission.

Q. What is your overall recommendation concerning the Gadsby and West Valley CT heat rates?

A. The Company's West Valley heat rate error has already been corrected in the Company's updated net power costs, and Gadsby heat rates are consistent with actual operation. Therefore, no further adjustment is necessary and Mr. Falkenberg's proposed adjustment should be ignored.

<u>"Market" Valuation of New Resources</u>

Q. What is the issue with respect to "market" valuation of new resources?

A. In order to address what Mr. Falkenberg describes as a "cost shifting" issue, he recommends that a "market-based" approach be applied to the most recent capacity additions, Gadsby and West Valley, and all future resources. Under this approach, the output from these units would be valued at market, irrespective of the Company's actual costs.

Q. Do you agree with this approach?

A. Absolutely not, for a number of reasons. First, rates are required to be cost-based. There is no principle for departing from this requirement with respect to new resources. Second, even assuming it was otherwise acceptable to value resources on a market basis, it is arbitrary to apply the principle selectively, to only the resources identified by Mr. Falkenberg as "new." The results would be entirely different, for example, if the Company were allowed to price the output from its fully depreciated thermal units at "market" rather than cost. Third, the precedent cited by Mr. Falkenberg is not supportive of his approach. The Black Hills contract cited in Mr. Falkenberg's testimony as a "surrogate" for valuing Colstrip 3 was in fact cost-based, not market-based. As Mr. Falkenberg acknowledges in his footnote 69 on page 74, the applicable FERC requirement at the time the Black Hills contract was executed in January 1984 was that the contract be cost-based.

Q. What is your recommendation with respect to this adjustment?

A. This adjustment should be rejected. The issue of cost shifting is discussed more completely in Mr. Duvall's testimony. As discussed by Mr. Duvall, this issue can be addressed more effectively than by resorting to a radical departure from cost-based pricing.

Updated Net Power Costs

Q. What is the Company's updated proposed net power cost?

A. As shown on Exhibit No. ___(MTW-11), the Company's updated proposed net power cost is $555 million Total Company compared to the $553 million included in our original filing. The study includes the corrections I discussed above and the other parties' adjustments which I have adopted. These net power costs should be used as the starting point for any adjustments adopted by the Commission.

Q. Does this conclude your rebuttal testimony?

A. Yes.