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

A. Yes.

Introduction

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/adjustments and the adoption of other party's adjustments,
- CCS witness Falkenberg's short-term firm transaction adjustment,
- CCS witness Yankel's alternative short-term firm transaction adjustment,
- Mr. Falkenberg's Swift Failure adjustment,
- DPU witness Coon's CT commitment and quick start reserve adjustment,
- Ms. Coon's proposed VISTA hydro weighting adjustment and Mr. Falkenberg's VISTA hydro modeling adjustment,
- Ms. Coon's and Mr. Falkenberg's CT forced outage rate adjustments,
- Ms. Coon's wind resource adjustment,
- Mr. Falkenberg's Reserve modeling and Ms. Coon's regulation adjustments,
- Mr. Falkenberg's P4 Production adjustment,
- CCS witness Hayet's adjustments for the US Magnesium, Desert Power and Kennecott / Tesoro contracts,
- Mr. Falkenberg's outage adjustments for Hunter 1, Blundell deration, Hayden Unit 1, and Colstrip 4, and
- Mr. Falkenberg's wind shape modeling adjustment.

I will not be addressing the Gadsby steam generation, BPA peaking contract and hydro load following adjustments proposed by Ms. Coon in her direct filed testimony because these adjustments were withdrawn in her supplemental direct testimony filed with the Commission. Mr. Reed C. Davis will address Ms. Coon's proposed Utah Load forecast and system loss adjustments and Mr. Hayet's system loss adjustment. Mr. Falkenberg's Fort James, Cal ISO and Kennecott Reimbursement adjustments are adopted in the Company's net power cost figure. Mr. Watters will address Mr. Falkenberg's proposed Aquila hydro hedge and West Valley lease adjustments. Mr. Woolley will address the Jim Bridger 4, Hunter Transformer, HDN 1, Colstrip 4, and other Company error outage adjustments.

Net Power Cost Adjustments

Q. Please explain the type of adjustments you have made to the Company's net power costs.

A. The Company's net power cost adjustments include (1) adjustments proposed by other parties that are being adopted by the Company, (2) adjustments proposed in response to other parties' adjustments, and (3) the impact of new contracts, corrections and other information that has become available since the original filing or arising from the discovery process in this case. This ensures that adjustments provided by interveners are appropriately matched by all available and relevant information. These adjustments increase proposed net power costs from $745.2 million to $745.56 million Total Company, and should be the starting point for any adjustments adopted by the Commission. The adjustments are summarized on Exhibit UP&L___ (MTW-1R)

Q. Please describe the adjustments.

A. The Company made the following adjustments in its net power costs, with the impact of each adjustment shown incrementally on a Total Company basis:

- VISTA Hydro Weighting – The original filed NPC modeled 19 hydro scenarios that ranged from a 5 percent to a 95 percent exceedence level using information from the Company's VISTA hydro model. Based on the review of the Ms. Coon's recommendation to use a normal distribution and Mr. Falkenberg's recommendation to use a weighting that is closer to a normal distribution, the Company is recommending the use of median hydro (50 percent exceedence level) in lieu of the previously proposed method. This produces a reasonable solution to the concerns raised by the other parties and greatly simplifies net power cost modeling. This reduces net power costs by $1.49 million.

- September Forward Price Curve – The original filed NPC used the March 31, 2004 Official Forward Price Curve. This adjustment incorporates the latest Official Forward Price Curve dated September 30, 2004 as requested by Ms. Coon. This increases NPC by $.98 million.

- Kennecott and Tesoro QF Contracts – This adjustment incorporates new QF contracts signed since the original filing. A similar adjustment is proposed by Mr. Hayet. The new contracts increase NPC by $1.0 million.

- Morgan Stanley Call Contract – This adjustment is similar to the Kennecott and Tesoro contract adjustment proposed by Mr. Hayet in that it incorporates a new 25 MW summer capacity contract signed since the original filing. The contract hedges price and reliability risk for retail customers in the Company's eastern control area. The new contract increases NPC by $0.47 million.

- Canadian Entitlement – Previously, hydro data did not include the Canadian Entitlement return so it was modeled separately. The new VISTA data is net of the Canadian Entitlement return. The separate modeling of this contract is removed to eliminate the double count. This correction decreases NPC by $5.31 million.

- Colorado to East Main transmission – This adjustment is similar to the Kennecott and Tesoro contract adjustment proposed by Mr. Hayet in that it incorporates new contracts, signed since the Company's original filing. These contracts provide transmission to move Craig and Hayden generation to the Utah bubble. The capability was forecasted in the original filing. However, the fixed cost associated with the capability was inadvertently not included. This correction increases NPC by $1.83 million.

- Thermal Plant Maximum and Minimum Capacities – This adjustment updates thermal plant maximum and minimum capacities, based on a periodic review of historical information. The primary input change is the increase of the minimum operating value of Cholla Unit 4 to 250 MW. Cholla's minimum load is controlled by its electrostatic precipitator performance (ESP). When the ESP is degraded by a phenomenon called sodium depletion, the minimum load for Unit 4 is 250 MW. This is included in response to the review performed by the Company as a result of CCS data request 8.95 and increases NPC by $2.27 million.

- Marginal Units – The original filed NPC incorrectly assigned reserve credits for Cholla 4 and other coal units to all the Gadsby CT, Gadsby Steam and West Valley CT units in the commitment decision. A reserve credit is the value credited to the higher cost gas units in the commitment logic when they carry reserves in lieu of reserves being carried on a lower cost coal plants. The previous modeling resulted in uneconomic generation because the sum of the reserve carrying capability on the gas plants exceeded the level of reserves carried on the coal units. This revision is included in response to the review performed by the Company in relation to the CT dispatch adjustments proposed in Ms. Coon's and Mr. Falkenberg's testimony. This correction limits the number of gas units receiving a reserve credit and decreases NPC by $.81 million.

- CT Thermal De-Rates – The Gadsby CT and West Valley CT thermal de-rates used in GRID are calculated based on an average of historical and manufacturer data because four years of historical information is not available. As indicated in Ms. Coon's testimony, the average calculation was incorrectly calculated placing too much emphasis on the manufacturer data. This adjustment corrects the error in the formula and increases NPC by $1.15 million.

- CT Quick Start Availability – Dispatch personnel indicated at a November 2004 Technical Conference that they carry quick start reserves on one Gadsby CT unit and one of the West Valley CT units. Mr. Falkenberg's direct testimony reflected this view. Subsequent to the technical conference, West Valley plant operators clarified that they believe all West Valley CT units can carry Quick Start reserves except during conditions of high humidity and cold temperatures. The Gadsby CTs are restricted to one unit due to pipeline constraints. The original filed NPC allowed all Gadsby and West Valley CT units to hold Quick Start reserves. This adjustment removes quick start capability from two Gadsby CT units and increases NPC by $7.1 million.

- Swift 2 In-service – The Swift 2 hydro unit was originally expected to be returned to service April 1, 2006. The unit is now expected to be returned to service on January 1, 2006. This expectation was reaffirmed on December 21, 2004. This revision partially adopts Mr. Falkenberg's proposed adjustments and decreases NPC by $2.67 million. The Company's adjustment does not adopt the portion of Mr. Falkenberg's adjustment that assumes Swift 2 will be in-service prior to January 1, 2006.

- Short Term Firm Sales and Purchases – This adjustment incorporates new STF contracts executed after the Company's original filing. This adjustment was updated at the request of Ms. Coon and is consistent with Mr. Hayet's proposal to include the new Kennecott and Tesoro contracts increases NPC by $6.30 million.

- Fort James (Georgia-Pacific Camas) Contract – This adjustment adopts Mr. Falkenberg's proposal to update Fort James generation based on historical experience. This update decreases NPC by $0.41 million.

- P4 Contract – This adjustment includes the excess demand credit which was inadvertently omitted from the Company's original filing. This adjustment corrects the omission and increases NPC by $1.46 million.

- Idaho Irrigation Load Control program – This adjustment includes this program as requested by Ms. Coon since it was omitted from the Company's original filing as requested by Ms. Coon. This adjustment decreases NPC by $0.13 million.

- CT Variable O&M – This adjustment incorporates the incremental cost per MWh of future overhauls for the Gadsby and West Valley units in the ***commitment*** decision. The incremental value recognizes that the units have a set number of service hours that they can be operated before a major overhaul is required. It should be noted that the overhaul cost included in the commitment decision is ***not*** included in NPC. This revision is included in response to the review performed by the Company in relation to the CT dispatch adjustments proposed by Ms. Coon and Mr. Falkenberg. This correction increases NPC by $0.07 million.

- Constellation Call Contract – This adjustment is similar to the Kennecott and Tesoro contract adjustment proposed by Mr. Hayet in that it incorporates a new 100 MW summer capacity contract signed since the original filing. The contract hedges price and reliability risk for retail customers in the Company's eastern control area. This adjustment increases NPC by $3.50 million.

- AMPS Colstrip Transmission – The topology included in the Company's original filing placed Colstrip in the West Main transmission area because of the combination of a long term transmission contract with BPA and a long term sales contract with Flathead. The new topology adds more transmission detail and models a more accurate view of how the Colstrip generation is delivered to the Company's control area. In addition, the revised topology corrects an invalid assumption that non-firm transmission is generally available from Hot Springs to Mid Columbia. This correction increases NPC by $1.75 million.

- Deferrable Thermal Maintenance – The Company performed a review of coal generation as a result of CCS data request 8.95. The review showed that the original filed NPC incorrectly assumed deferrable thermal maintenance was performed only during weekend hours. As shown on the historical information summarized as Exhibit UP&L___ (MTW-2R), this maintenance is not limited to weekends and demonstrates that GRID was producing more coal generation on-peak and less off-peak than occurred during the 48-Month historical period ended March 2004. This correction more accurately reflects the operation of the Company's thermal facilities and increases NPC by $4.53 million.

- Klamath / Swift 2 Hydro Generation – The Klamath River VISTA generation included in the Company's original filing included an input error and a change in the Bureau of Reclamation's operating strategies previously addressed. The data error was associated with streamflow used in the model simulation that was biased toward wetter than average conditions generated a streamflow of approximately 949,000 MWh. Correction of the error results in a total annual generation of approximately 775,000 MWh. Additionally, endangered species act requirements, fishery obligations, tribal trust responsibilities and other environmental considerations in the upper Klamath Basin and on the Klamath River below Iron Gate dam have increased the pressures on water supply. To help ensure full delivery of water to Klamath Irrigation Project farmers, the US Bureau of Reclamation has routinely directed the amount of flow through the Company's hydro facilities. These actions have reduced the Company's hydro operating flexibility and operating effectiveness. These operating constraints are now included in VISTA simulations to reflect the US Bureau of Reclamation's water management policies and flow directives. The adjustment also includes runner upgrades at JC Boyle on the Klamath River and the expected Swift 2 turbine efficiency improvement. This adjustment increases NPC by $4.00 million.

- Small Hydro Generation – The VISTA hydro generation for the Small East Plants (Ashton and PCE Minor) and Rogue River Plants (Eagle Creek and Prospect 1-4) included in the Company's original filing had data errors and was overstated. This revision corrects the generation and increases NPC by $1.08 million.

- West Side Transfer – At a November 2004 technical conference with scheduling personnel and Mr. Falkenberg, scheduling personnel stated that to the extent that transmission is available on Path C, up to 100 MW of operating reserves may be held in the western control area (PACW) for the eastern control area (PACE) by rescheduling some of the Bridger generation southbound. The Company's original filed net power cost did not model this assumption. This adjustment corrects the Company's modeling, corrects Mr. Falkenberg's proposed reserve modeling adjustment, and decreases NPC by $3.40 million.

- US Magnesium Contracts – Mr. Hayet proposed an adjustment to include the new QF contract. This adjustment incorporates the QF purchase, reserve purchase and load curtailment contracts, which have been or are expected to be approved by the Utah Commission. This update decreases NPC by $1.83 million.

- Thermal Generation Ramping – The Company performed a review of coal generation as a result of CCS data request 8.95. The review showed that the original filed net power costs overstated coal generation because thermal availability rates assume that coal units are available at full load when the units are being shut down for maintenance and when restarted after maintenance and forced outages. In reality, generation is lost while a unit ramps to the minimum level required to synchronize with the grid and when a unit is being shut down for repairs and planned maintenance. A breakdown of generation lost due to ramping is included in my testimony as Exhibit UP&L___ (MTW-3R). This adjustment corrects the Equivalent Forced Outage Rates (EFOR) to account for the lost generation and increases NPC by $2.65 million. It should be noted that this adjustment is conservative because the Company does not have this data for plants that are operated by shared owners.

- Station Service – The Company performed a review of coal generation as a result of CCS data request 8.95. The review showed that the original filed net power costs overstated coal generation because station service for coal plants offline was not captured. Station service is not captured in energy sales or revenue calculations either. A breakdown of station service not captured in the original filed net power costs is included in my testimony as Exhibit UP&L___ (MTW-4R). This adjustment corrects coal generation and increases net power costs by $2.89 million. It should be noted that the adjustment is conservative because the Company does not have station service data for (1) plants that are operated by shared owners, and (2) Jim Bridger because of the metering configuration.

- Coal Prices – This adjustment is similar to the Kennecott and Tesoro contract adjustment proposed by Mr. Hayet in that it incorporates new coal contract terms that will be in effect during the test period. The Cholla coal price was increased $6.91 per ton to reflect a rail price increase resulting from the Surface Transportation Board's decision on December 13, 2004 to vacate the rate prescription previously imposed in 1998. The coal costs for Carbon, Hunter and Huntington have been adjusted to reflect an agreement with Arch Coal Sales Company regarding the pricing for Dugout and Sufco coal purchases under long-term coal supply agreements. This adjustment increases NPC by $5.33 million.

- Cal ISO Wheeling – In response to a data request, the Company indicated Cal ISO wheeling expense expectations had decreased after the Company's original filing. This adjustment updates costs, adopts Mr. Falkenberg's proposed adjustment and reduces net power costs by $5.50 million.

- Fixed Pipeline Reservation Fee – The Company's original filing did not properly align the start of the gas pipeline reservation fees with the in-service date of Currant Creek. This update aligns gas pipeline expenses with the in service date of Current Creek and increases NPC by $3.39 million.

- Tri-States Purchase – The adjustment incorporates a contractual price increase recently provided by Tri-State along the lines of Mr. Falkenberg's proposed Cal ISO adjustment which incorporates updated information that became available after the Company's initial filing. This adjustment increases net power costs by $1.36 million. The Tri State letter is provided as Exhibit UP&L**___ (**MTW-5R)**.**

- Foote Creek Wind – This adjustment corrects and improves on the project output shaping adjustment proposed by Mr. Falkenberg. Wind shaping is based on data from the Energy Information Administration. The amount of energy produced by the project is also updated based on historical experience for the 48 month period ended March 2004 consistent with Mr. Falkenberg's proposed Fort James adjustment, which reduces generation based on historical experience. This adjustment increases net power costs by $.51 million.

- Kennecott Reimbursement (Generation Incentive) Contract – In response to a data request, the Company indicated that the calculation of the Kennecott Generation Incentive contract was incorrect. This adjustment corrects the error, adopts Mr. Falkenberg's proposed adjustment, and reduces net power costs by $.28 million.

- Line Losses – This adjustment updates the line loss assumptions included in the Company's load forecast as discussed in Mr. Davis's rebuttal testimony. The proposed adjustment is based on Mr. Davis's review of adjustments proposed by Ms. Coon and Mr. Hayet and reduces net power costs by $6.5 million.

- Desert Power QF – This adjustment updates contract pricing to reflect the terms of the new contract. This adjustment reduces net power costs by $.28 million.

- Current Creek Combined Cycle – The plant was included in net power costs for the month of March 2006 to reflect the expected in-service date. This adjustment reduces net power costs by $2.65 million.

- Gas Sales – Natural gas consumption at gas-fired plants is influenced by interaction of other resources, gas prices and market prices. This adjustment updates gas prices and incorporates the sale of excess gas resulting from the revised dispatch of Utah gas generation units, which is predicated upon updates discussed above. This adjustment decreases NPC by $22.0 million.

The adjustments to the net power costs were originally discussed with the parties during settlement meetings in early December 2004. On December 15, 2004, a draft of the adjusted net power costs was provided to the parties that sponsored net power cost testimony. On January 12, 2005, the final adjusted net power costs that are incorporated in my rebuttal testimony were provided to the parties that sponsored net power cost testimony. It should be noted that the impact of each adjustment was calculated incrementally in the order shown above. If these adjustments were calculated in a different order or if only some of the adjustments were adopted, the value would be different for most of these adjustments because each adjustment impacts the other adjustments. Therefore, if the Commission adopts some of the adjustments proposed by other parties or does not adopt some of the Company's adjustments, authorized net power costs would need to be recalculated with the GRID model to determine final adopted net power costs.

CCS Adjustments for Short-Term Firm Transactions

Q. Please explain the proposed adjustments.

A. CCS proposes two alternative adjustments for short-term firm transactions, one sponsored by Mr. Falkenberg and one sponsored by Mr. Yankel.

Q. Please describe Mr. Falkenberg's adjustment.

A. Mr. Falkenberg proposes to adjust the actual price of executed short-term firm transactions included in the Company's original filing to match the Company's March 31, 2004 forward price curve. He believes there are some serious problems with the Company's short-term transaction modeling because the Company includes only known short-term firm transactions and lets the GRID model balance load requirements with system balancing transactions. He believes this method overstates net power costs because the preponderance of actual transactions included in GRID are "below market" and that one would not consistently expect the Company to make "below market" sales. He expects the actual volume of short-term firm transactions to be much greater than the Company has modeled, and that the transactions not modeled would lower net power costs. His proposed adjustment would reduce net power costs by $13.4 million.

Q. Do you agree with the proposed adjustment?

A. No. Mr. Falkenberg's testimony includes numerous inaccuracies and misstatements that, when corrected, fail to support his proposed adjustment.

Q. **Please explain.**

A. At the outset, the Company did not enter into "below market" transactions.

The transactions were prudently entered at market prices. Mr. Falkenberg does not seem to dispute this point; the CCS response to Company data request 5.3 states:

> Mr. Falkenberg accepts that these trades were at market when entered, based on his analysis of the trades and the forward prices applicable.

A copy of this response is included with my testimony as Exhibit UP&L___ (MTW-6R). Mr. Falkenberg's "below market" characterization simply means that the transactions were entered at market prices, but subsequently wholesale market prices increased which, based on a current comparison of the transacted prices, gives the appearance of being "below market." Thus the transactions were prudently entered at market. So, his reference to "below market" transactions is misleading. In addition, as I will discuss later in my testimony, if it is appropriate to adjust actual short-term firm transactions to market, it would also be appropriate to adjust forward gas purchases to market rates, which would significantly increase net power costs.

Q. Does Mr. Falkenberg consider the short-term firm transactions included in the Company's original filed net power costs to be imprudent transactions?

A. No. In the CCS response to Company data request 5.5, Mr. Falkenberg indicated that the transactions were prudent. A copy of that response is included with my testimony as Exhibit UP&L___ (MTW-7R).

Q. Does Mr. Falkenberg believe market prices are in the Company's control and the Company should have attempted to time its transactions?

A. No. In the CCS response to Company data request 5.6, Mr. Falkenberg indicated that wholesale market prices do fluctuate, are not within the Company's ability to predict, and are not in the Company's control. A copy of that response is included with my testimony as Exhibit UP&L___ (MTW-8R).

Q. Do you agree with Mr. Falkenberg's suggestion that one would not consistently enter transactions which appeared to be "below market" under the circumstances involved here?

A. No. As indicated in the CCS response to Company data request 5.6, wholesale market prices fluctuate and are not under the Company's control. So I would expect that there could be periods of time when market prices decrease and sales transactions appear above market, and periods when market prices increase and sales transactions appear below market. Market purchases are affected in a similar manner. Of course, despite the fact that the Company does all it can do to keep net power costs as low as possible for customers, it is impossible to know with certainty what will happen. The important thing to remember here is that the transactions were prudently entered to balance the Company's system at market prices and therefore should be recoverable.

Q. Has Mr. Falkenberg proposed this type of adjustment in previous cases, when market prices have moved in the Company's favor?

A. No. He has not proposed such a short-term firm adjustment when it would result in an increase in net power costs.

Q. Are there any examples in this case where the Company's forward transactions have had the opposite effect on customers, i.e., a reduction in net power costs?

A. Yes. Through our gas hedging strategy, the Company purchased gas forward at prices that are now substantially below current market prices and expectations during the test period. The Company has included an adjustment in its updated net power costs that sells excess gas at the Company's September 30, 2004 forward price curve. This adjustment reduces net power costs by $22.4 million. If the Commission were to adopt the sort of regulatory policy illustrated by Mr. Falkenberg's proposed adjustment, it would also be appropriate to remove the Company's gas sales adjustment and to adjust forward gas purchases to market. This would substantially increase net power costs.

Q. Is the Company's short-term firm methodology consistent with previous commission treatment?

A. Yes. The Company's short-term firm methodology—which includes actual short-term firm transactions and allows GRID to balance the Company's load requirements through system balancing sales and purchases—is consistent with prior Commission treatment of including actual short-term firm transactions. The only difference between this case and prior cases is the test periods. Previous cases were historical and this case is a forecast test period, which results in a lower volume of executed transactions. However, customers are not disadvantaged by the lower volume as Mr. Falkenberg asserts.

Q. Mr. Falkenberg stated that the Company excluded 80 percent of typical short-term firm volume and that this results in an overstatement of net power costs. Is this an accurate statement?

A. No, Mr. Falkenberg's analysis excluded a significant number of transactions that should have been included in his analysis. Net power costs are not overstated by the Company's short-term transaction modeling.

Q. What transactions did Mr. Falkenberg's analysis exclude?

A. His analysis failed to include GRID-calculated system balancing transactions. System balancing transactions are a surrogate for projected short-term firm and non-firm transactions that are necessary to balance the system. Since a very high percentage of short-term transactions entered by the Company are short-term firm, these transactions should be included in his analysis. So, contrary to Mr. Falkenberg's assertion, the cost of balancing the Company's system is projected.

Q. Is there anything unusual about a forecast test period including a lower volume of executed transactions compared to a historical test period?

A. No. A lower volume of executed transactions is expected for a forecast test period that has not yet occurred, as compared to a historical period that has already occurred. However, it is important to remember that this lower volume of executed transactions simply results in a higher level of GRID calculated balancing transactions executed at market.

Q. Does the inclusion of balancing transactions still result in a lower overall volume of short-term firm transactions than compared to actual results?

A. Yes. This is also expected, because GRID balances loads and resources hour-by-hour with perfect foresight based on a fixed forecast of load and resources. On the other hand, actual results take into account all load and resource changes of the system and market liquidity, which cause higher short-term firm transaction volumes.

Q. Can you provide an example of why actual results produce higher short-term firm transaction volume?

A. Yes. Here are two examples.

<u>Example 1</u>: Due to market liquidity issues and the timing of entering into short-term firm transactions, the Company is generally able to acquire or sell only standard annual, quarterly, monthly, or balance-of-month products. Standard products are shaped like 7x24 and 6x16 etc. and do not perfectly match load requirements. These transactions are executed with the expectation that the entire product is not needed and a portion will need to be resold in the wholesale market. This creates a higher volume of actual transactions than would occur in a general rate case where GRID balances the system perfectly hour by hour.

<u>Example 2</u>: On an actual basis, loads and resources fluctuate. At a given point in time, the Company may be long for a forward period and execute short-term firm sales transactions to reduce the length. However, in the time leading up to delivery, load expectations may change for a number of reasons, which result in the Company being short and requiring purchases to cover the short. This creates a higher volume of transactions than would exist in a general rate case where GRID balances the system with a point forecast that does not vary.

As discussed, it is not surprising that GRID balances the system with a lower volume because it is balancing a point forecast hour by hour with perfect foresight**.**

Q. Does this lower volume result in an overstatement of net power costs?

A. No. Mathematically there would be no difference in the cost of short-term firm transactions in the rate case, if the Company forecasted more standard product transactions. For example, if the Company forecast a standard 6x16 purchase at the Company's forward price curve, the product would cost the same as if the GRID model bought the same volume on an hour by hour basis, because hourly prices are developed from the same price curve. The net cost would also be the same if it were assumed that a portion of the standard product would be resold in the market, because it would be sold at the hourly prices developed from the forward heavy load hour prices.

Q. Earlier you mentioned that net power costs have been adjusted to reflect new short-term firm transactions executed since the Company's original filing. What is the impact of that adjustment?

A. The adjustment significantly increased the volume of short-term firm transactions and increased net power costs by approximately $6.3 million. Contrary to Mr. Falkenberg's assumption that a higher volume would lower net power costs, that does not appear to be the case.

Q. Mr. Falkenberg stated that many profit opportunities that the Company's traders will strive to exploit are not included in GRID. Is this the case?

A. No. It is important to remember that the Company for the most part buys and sells energy to balance its system. In these instances there are no profit motives, because the Company cannot exactly predict market prices and has no control of those market prices. The Company does execute simultaneous spread transactions to optimize its transmission system when there is a price differential between market hubs and transmission is available. To the extent these transactions have been executed, they are included in the Company's net power costs.

Q. Does GRID model logic capture spread transaction opportunities?

A. Yes. GRID economically buys and sells energy when transmission is available. Mr. Falkenberg is simply incorrect when he claims that profit opportunities are not captured in GRID.

Q. What is your recommendation for this adjustment?

A. As I have clearly demonstrated, the information and assumptions upon which Mr. Falkenberg supports his adjustment are wrong or are misleading: (1) the actual transactions are prudent and were not entered "below market," (2) a forecast of transactions necessary to balance the system is included in the Company's forecast, (3) it is appropriate that net power costs based on point forecast have a lower volume of short-term firm transactions, (4) the lower volume does not adversely impact customers, (5) the higher volume of transactions included in the Company's adjusted net power costs actually increased net power costs, and (6) the GRID model captures profit opportunities through its optimization logic. For these reasons, the Commission should reject the proposed adjustment and allow the Company to recover its prudently incurred costs.

Q. What is your recommendation regarding Mr. Falkenberg's recommendation to initiate a task force to study the Company's modeling?

A. Just as there is no basis for his adjustment, there is no basis to initiate a task force. The proposal should be rejected.

Q. Is Mr. Yankel's proposed adjustment an alternative recommendation to Mr. Falkenberg's short-term firm modeling adjustment?

A. Yes. The adjustment is a secondary proposal that would be considered in the event Mr. Falkenberg's adjustment is rejected.

Q. Please explain Mr. Yankel's proposed adjustment.

A. Mr. Yankel proposes to align the price ratio of short term firm transactions included in GRID with the historical price ratio between STF purchases and sales. He makes this adjustment by adjusting the price of actual short-term firm purchases so the ratio is comparable with history. The proposed adjustment would decrease net power costs by $22.8 million.

Q. Do you agree with the proposed adjustment?

A. No. The adjustment is utterly without merit and should be rejected. Mr. Yankel inappropriately excluded GRID-calculated system balancing transactions, and failed to take into consideration the fact that the Company's super-peak load requirements are growing faster than energy requirements. Also, because of changes in the Company's load requirements and pricing differences in the market, the adjustment does not produce valid results.

Q. Please explain the problem with Mr. Yankel's exclusion of balancing transactions.

A. As I explained above, GRID system balancing transactions are a surrogate for short-term firm transactions and should be included in his analysis. If the system balancing transactions were included, his analysis would have shown that the price ratio of short-term firm purchases to sales included in the Company's filing is consistent with the historical ratios Mr. Yankel calculated. A correction of Mr. Yankel's analysis is included with my rebuttal testimony as Exhibit UP&L___ (MTW-9R). However, as I explain below, this is probably nothing more than sheer coincidence because of the changes in the Company's system and market volatility. Nonetheless, it should give the Commission another reason, in addition to the reasons discussed above in my rebuttal of Mr. Falkenberg's testimony, to find that the Company's modeling of short-term firm transactions is reasonable**.**

Q. Is it reasonable to expect that the price ratio in the future would be the same as it was historically for these types of transactions?

A. Not in most cases. I would expect the price ratios to be the same only if loads and resources were static between the historical and future test periods analyzed, the weighted volume of sales and purchases were very similar both on-peak and off-peak, and market price movements after execution of the transactions were very similar. Given the volatility that is present in the wholesale market and the changes in the Company loads and resources, the past is not a good predictor of the future price ratio for these types of transactions. If any of these factors were dissimilar, it would be only by sheer coincidence that the type of analysis employed by Mr. Yankel, corrected to include system balancing transactions, would produce similar results.

Q. Are there changes occurring in the Company's system that would actually lead one to believe the price ratio of purchases to sales should be increasing?

A. Yes. In Utah, super-peak requirements have been growing faster than energy requirements. This alone would result in a higher price ratio for purchases compared to sales, given the need to pay a higher price for energy during the super peak periods and the lower price received for sales during the shoulder periods.

Q. Does recent historical information show a higher price ratio?

A. Yes. For the twelve month period ended October 2004, the price ratio of short-term firm purchases to sales averaged 1.36 compared to the 1.08 historic average used by Mr. Yankel.

Q. What is your recommendation for the Commission?

A. The analysis employed by Mr. Yankel is not useful for this type of adjustment due to market volatility and system changes, and thus the adjustment should be rejected. It should be noted, however, that once his analysis is corrected, it confirms that the GRID results are reasonable.

Swift Canal Failure

Q. Please explain the proposed adjustment.

A. Mr. Falkenberg proposes to treat the failure of Cowlitz PUD's Swift 2 hydro generation facility and the associated loss of reserve carrying capability on the Company's Swift 1 hydro facility as if the failure never happened. He considers his proposal to be reasonable because (1) he believes the repairs will be substantially completed only a few months into the test year which assertedly will allow the Company to begin carrying operating reserves on Swift 1, and (2) the failure of Swift 2 was an unusual event. The proposed adjustment would reduce net power costs by $5.9 million Total Company.

Q. Do you agree with the proposed adjustment?

A. No. The Swift 2 project is not expected to be placed in service until January 1, 2006. Consequently, the adjustment would cause a mismatch between costs and benefits. Mr. Falkenberg's adjustment also includes an error.

Q. Can the Company carry operating reserves on Swift 1 hydro project before Swift 2 is placed in service, as Mr. Falkenberg suggests?

A. No. The Company will not be able to carry reserves on Swift 1 until Swift 2 is placed in the Company's control and that will not happen until Swift 2 is placed in service. Conversations with Cowlitz Staff as recently as December 21, 2004 indicate the return is not expected until January 1, 2006.

Q. For purposes of setting rates, is it reasonable to assume that the Swift 2 failure did not occur?

A. No. As a result of the outage, the Company is prudently incurring additional costs to serve customers and should recover those costs. Adoption of Mr. Falkenberg's proposed adjustment would incorrectly model the capabilities of the Swift project and provide benefits to customers in the form of lower net power costs. This would result in a mismatch between costs and benefits. For this reason, the proposed adjustment should be rejected.

Q. Please explain the error in Mr. Falkenberg's adjustment.

A. Mr. Falkenberg failed to remove a wholesale sale to Cowlitz PUD that is tied to the Swift 2 outage. The sale terminates when Swift 2 goes back in service. If the outage is assumed not to have happened during the test period, the sale must also be removed. This correction would reduce the proposed adjustment from a $5.9 million reduction to a $1.7 million reduction.

Q. Should the Company's treatment of the Swift 2 outage in other jurisdictions have any bearing on the treatment in Utah?

A. Not in this instance, given that the circumstances surrounding the filings in other jurisdictions are different. First, in the Washington case cited by Mr. Falkenberg, the exclusion was merely a way to get to a stipulated net power cost number and overall case agreement with the WUTC Staff. None of the adjustments established a precedent and therefore should not be considered in this case. On the other hand, if Mr. Falkenberg considers the stipulation and its adoption by the Washington Commission to set a precedent, then many of the adjustments, particularly the outage adjustments proposed by Mr. Falkenberg, should be rejected for similar reasons, because they were not adopted by the Washington Commission. Second, the outages were not included in the other filings cited by Mr. Falkenberg – Oregon Docket UE-147 and Utah Docket No. 03-035-10 – because the full extent of the outages was not known at the time of the filings. That is certainly not the case in this filing. Third, the outage was inadvertently excluded from our Wyoming filing, but the impact of the outage was subsequently included in Wyoming rates through the $9.2 million increases adopted for increased net power costs in Docket No. 20000-EP-04-211.

CT Commitment and Quick Start Reserves

Q. Please explain the proposed adjustment.

A. Ms. Coon does not believe the Gadsby and West Valley CT dispatch in the Company's original filed case is consistent with actual dispatch or normal utility practice. This belief is based on historical information that shows the units operate near their maximum capacity and have lower heat rates compared to GRID, which operates the units at lower capacity factors and higher heat rates. She also recommends that GRID should be programmed so that it can carry quick start reserves. Based on a GRID analysis where Ms. Coon used an artificial minimum capacity of .001 MW to "trick" GRID into simulating the commitment of the CT units in a different manner, she proposes to reduce net power costs by $13.6 million.

Q. Do you agree with the proposed adjustment?

A. No. However, I do agree that the simulation of the CT units was incorrect in the Company's original filed net power cost study. As a result, the Company made several adjustments in its revised net power costs. The modeling was corrected through the Marginal Units, CT Thermal Derates, Quick Start Availability and Westside Transfer adjustments that were discussed above. With respect to Ms. Coon's proposed adjustment, however, I disagree with the approach and justification.

Q. Does the "trick" used in Ms. Coon's GRID run produce reasonable results?

A. No. The CT quick start capability does not provide the spinning reserve component of operating reserves. The GRID modeling "trick," which is the basis of Ms. Coon's proposed adjustment, incorrectly allows the units to be credited for holding too many spinning reserves.

Q. Does Ms. Coon's "trick" also incorrectly claim too much quick start capability?

A. Yes. In addition to the limitations discussed above, quick start capability is dependent upon having a firm gas supply and gas must be prescheduled a day ahead. The GRID modeling "trick" incorrectly assumes that firm gas supply would be nominated for all hours of every day when it is not.

Q. Is there reason to reprogram the GRID model to carry reserves when the CT units are offline?

A. No. The version of GRID being used in this case already includes logic to carry quick start capability.

Q. Does the fact that GRID has higher heat rates and lower capacity factors for the CT units indicate a problem in GRID?

A. No. The GRID model's aggressive modeling of the CT units has not been matched in actual practice to date. Initially, when the units were new, the units were dispatched at a near full capability to meet load. As the Company schedulers gain more experience with the individual units, the actual dispatch of the CT units is trending toward increased frequency of dispatch at 20 MW in order to allocate operating reserves to the units. If the CT units were modeled in GRID consistent with actual practice to date, heat rates would be lower, but net power costs would be higher in this case.

Q. What is your recommendation for this adjustment?

A. Ms. Coon's GRID run that included the "trick" does not produce correct results and should be rejected. The Company's adjusted net power costs correct the commitment and dispatch of the CT units and should be adopted by the Commission.

Hydro Modeling / Weighting of VISTA Hydro Scenarios

Q. Please explain Mr. Falkenberg's proposed adjustment for hydro modeling.

A. Mr. Falkenberg proposes to use what he considers to be a more realistic probability distribution. This adjustment is based on his belief that the 19-scenario VISTA methodology overstates the likelihood of extreme events. The proposed adjustment would reduce net power costs by $1.3 million.

Q. Do you agree with Mr. Falkenberg's claim that different time periods for input data is a weakness in the VISTA modeling?

A. No. Each river system is evaluated based on historical data that is available for that particular river system. The Company views this aspect of the VISTA modeling as a strength, because it makes it unnecessary to exclude or manufacture data.

Q. Please explain.

A. In order to match all time periods, the Company would have to either exclude some years or manufacture data. For example, BPA provides data for the Mid Columbia projects that corresponds to water years 1928/29 to 1987/1988. The Company's data for the Lewis river projects are from 1958 to January 2002. In order to match the Lewis river data to the Columbia river data, the Company would discard the data from October 1988 and beyond and manufacture data for October 1928 to September 1958. As the Company explained in the VISTA workshop, prior to the 1990s, BPA manufactured data for the region's non Columbia River projects to match the time period of its Columbia River data. The Company considers the VISTA methodology to be superior.

Q. Mr. Falkenberg claims that the 19 exceedence levels used to normalize results in an overstatement of extreme conditions. Do you agree?

A. The observation concerning the VISTA exceedence levels has some merit. However, he overstates the problem and his proposed solution is riddled with errors. To address this issue the Company proposes to abandon normalizing hydro availability with 19 exceedence levels in favor of using just the medium (50%) exceedence level.

Q. Please respond to the die example discussed in Mr. Falkenberg's testimony.

A. The die example is misstated. The meaning, however, is clear. To match the VISTA methodology, the one die example should read: There is an 87 percent chance of the die value exceeding one, a 67 percent chance of exceeding two, a 50 percent chance of exceeding three, a 33 percent chance of exceeding four, and a 17 percent chance of exceeding five. By definition exceedence levels of zero and 100 percent do not exist.

When his die example is extended to two dice, he overlooks an important factor: The Mid Columbia hydro and the Company hydro cannot be represented by two dice with each die having the values one to six. The Mid Columbia hydro is represented by a die with values from 2.3 to 13.9. This ratio reflects the relative size of the projects. Thus on the role of two dice, there is a 1/36 chance of having an outcome of 3.3 (i.e.1 plus 2.3).

Q. Mr. Falkenberg based his VISTA adjustment on a comparison of the prior fifty water year data to the VISTA output. Do you have any concerns with his comparison?

A. Yes. Mr. Falkenberg ignores the fact that one of the reasons for moving to the VISTA data is that the manufactured 50 year data are stale and obsolete. They do not reflect current regulations. Doing a correlation with this outdated data is therefore invalid from the beginning. Mr. Falkenberg's comparison of hydro is also invalid because he is comparing dissimilar data (i.e., apples to oranges). VISTA distills multiple data points to a single data point for each of the 19 exceedence levels. Mr. Falkenberg then takes this set of nineteen points, which are not a distribution, and compares them to a distribution. For his comparison to be valid, he would have to compare the distribution of the underlying VISTA data to the 50 year data. In order to do that he would have to manufacture data, for the reasons discussed above. Even then the comparison would be invalid because the 50 year data are outdated.

Q. Do you have additional concerns with the proposed adjustment?

A. Yes. Mr. Falkenberg's use of the data is improper. Again, he is using data which are not a distribution and is trying to use them as a distribution. For his 19x19 matrix to be valid, he would have to use the distribution of the underlying VISTA data. In order to do that, he would have to manufacture data, as discussed above, and that would turn his matrix into a 50x50 matrix.

Q. What is your recommendation for this proposed adjustment?

A. While Mr. Falkenberg's observation that using 19 sets of VISTA overstates the likelihood of extreme events has some merit, his proposed adjustment has numerous problems. I recommend that the Commission adopt a medium (50%) exceedence level for normalized hydro generation. The proposed adjustment would greatly simplify the time and effort necessary to calculate net power costs. The adjustment calculated in this manner would reduce net power costs by $1.49 million, which is slightly larger than the reduction proposed by Mr. Falkenberg.

Q. Did Ms. Coon propose an adjustment that was similar to the hydro modeling adjustment proposed by Mr. Falkenberg?

A. Yes. Ms. Coon proposed a similar adjustment that would reduce net power costs by $1.5 million. I recommend the same solution to her proposed adjustment.

Inclusion of New Wind Resources

Q. Please explain Ms. Coon's proposed adjustment for wind resources.

A. Ms. Coon proposes to include 100 MW of additional wind resources at a price of $35 per MWh, which she believes is appropriate given the extension of the federal production tax credit (PTC) through December 31, 2005 and the Company's stated intent to acquire wind resources. The proposed adjustment would decrease NPC by $1.2 million.

Q. Do you agree with the proposed adjustment?

A. Not completely. I do agree that it is likely that the Company will have acquired 100 MW of wind resources located in the West. However, no pricing has been contractually established at this time. The Company has therefore not included additional wind resources in the net power cost adjustments. In any event, I don't agree with her proposed pricing. The $35 per MWh price is too low given current market prices and approved QF rates in Idaho and Oregon.

Q. Please explain.

A. Many wind resources qualify as QFs under PURPA rules, so the price at which a wind developer would be willing to sell the resource output to the Company should approximate the Company's approved QF rates, less integration costs of approximately $5.00 per MWh. Therefore, if wind resources are included, they should be priced at approximately $42 per MWh. This level of pricing would change Ms. Coon's adjustment from a $1.2 million reduction to a $.6 million NPC increase.

Reserve Modeling and Adjustment of Regulation Amounts

Q. Please explain Mr. Falkenberg's proposed adjustment to reserve modeling.

A. Mr. Falkenberg proposes to (1) increase the amount of operating reserves supplied by Pac West (PACW) to Pac East (PACE) from 100 MW to 200 MW through the RTSA (dynamic overlay) contract with Idaho Power, (2) change the Quick Start capability of the CT units so that it is carried on one Gadsby CT and one West Valley CT, and (3) change the PACE regulating margin minimum and maximum of 50 MW and 125 MW to 0 MW and 50 MW, respectively. These adjustments are based on his belief that the gas-fired CT dispatch in GRID is unrealistic because once dispatched, GRID operates the CT units generally at minimum operating levels and the dispatch is not consistent with the actual operation of the CT units. He also believes the Company has overstated regulating reserve requirements. The proposed adjustment reduces net power costs by $4.8 million.

Q. Do you agree with the proposed adjustment?

A No. However, as I discussed above, I agree that the dispatch of the Gadsby and West Valley CT units in the original filing was incorrect. I do not agree with all of his proposed solutions to correct dispatch. I agree with the Quick Start adjustment for Gadsby and have incorporated the same adjustment in my net power cost adjustments, which increases net power costs by $7.1 million. I don't agree with the adjustment to the Dynamic Overlay because it is not possible from a contractual perspective. An adjustment similar to the dynamic overlay adjustment using Path C is appropriate. That adjustment, the Westside Transfer, was included in the Company's adjusted net power costs and reduces net power costs by $5.68 million. I also do not agree that the regulation reserve requirements are overstated in GRID.

Q. Did Mr. Falkenberg misinterpret the Dynamic overlay information discussed at the November 2004 technical conference?

A. Yes. The amount of transfer capability established through the RTSA contract (dynamic overlay) with Idaho Power allows the transfer of only 100 MW of operating reserves (spinning or non-spinning) from PACW to PACE. It cannot be increased as Mr. Falkenberg suggests. The correct interpretation is that 100 MW of capacity on Path C is at times reserved if transmission is available so that non-spinning reserves can be held on Jim Bridger for PACE. The Company's Westside Transfer adjustment models this in the adjusted net power costs. Through this adjustment, the transfer capability portion of Mr. Falkenberg's proposed adjustment has been corrected and adopted by the Company.

Q. Did the net power cost adjustments eliminate the deficiencies in the CT dispatch and modeling included in the Company's original filing?

A. Yes. In addition to the Westside transfer adjustment, the modeling was corrected through the Marginal Units, CT Thermal Derates, and Quick Start Availability adjustments that were discussed above.

Q. Based on the information from the same November technical conference, Mr. Falkenberg claims that in actual practice the upper bound for the PACE regulating margin is 50 MW. Is this true?

A. No. Again, Mr. Falkenberg's interpretation of the information presented at the November meeting is wrong. The 50 MW east control area requirement discussed in the technical conference represents the lost generation that is used for annual planning. The value is ***average*** MW, not ***peak*** MW, and is net of the transfers from PACW. In GRID, the regulating margin upper bound caps the requirement for a single hour and is before transfers, so Mr. Falkenberg's comparison and adjustment are not valid.

Q. Based on his interpretation of the NERC / WSCC standards, Mr. Falkenberg claims that the lower bound for the regulating margin should be zero. Do you agree?

A. No. Mr. Falkenberg's reading of NERC and WSCC standards is wrong. The guideline regarding regulating margin is not zero; but on the other hand it is not explicitly stated. Rather, it is inferred from the following section of the WECC Minimum Operating Criteria (Section 1.A.1. (a):

> Regulating Reserve. Sufficient spinning reserve, immediately responsive to automatic generation control (AGC) to provide sufficient regulating margin to allow the control area to meet NERC's Control Performance Criteria.

The GRID regulating margin calculation includes a component for automatic generation control (AGC). The 50 MW lower bound represents the amount of AGC reserved, which is required to match minute-by-minute changes in load requirements.

Q. Do you agree with Mr. Falkenberg's assessment that the Company's "unrealistic" dispatch of the CT units at 20 MW causes the Company to lose market opportunities to makes wholesale sales?

A. No. The GRID CT dispatch logic actually provides an opportunity to make market sales at a higher profit margin from lower-cost coal units and thereby lowers net power costs.

Q. Please explain.

A. The GRID dispatch and the reserve allocation logic use the relative position of the units in the resource stack. GRID arranges the resource stack in a descending incremental cost order. Reserves are allocated to units with a higher incremental cost. The Gadsby and West Valley CT unit have a higher incremental cost than the coal units. If a West Valley unit holds operating reserves in lieu of a lower cost coal unit, the result is a higher heat rate but an overall lower net power cost.

Q. Mr. Falkenberg notes that the 20 MW CT dispatch is not consistent with actual practice. Is this true?

A. Yes. As explained above, the GRID model's aggressive modeling of the CT units has not been matched in practice to date. Over time, the actual dispatch of the CT units is trending toward increased frequency of dispatch at 20 MW in order to allocate operating reserves to the units. If the CT units were dispatched in GRID consistent with actual practice, heat rates would be lower, but net power costs would be higher. For this and the other reasons discussed above, Mr. Falkenberg's proposed regulating margin adjustment should be rejected.

Q. Did Ms. Coon propose an adjustment that was identical to Mr. Falkenberg's proposed Reserve Modeling adjustment?

A. Yes. The only difference in the proposed adjustments is the title. Ms. Coon titled her adjustment "More Appropriate Regulation Amounts. This adjustment should be rejected for the same reasons I discussed above regarding Mr. Falkenberg's adjustment.

P4 Production

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 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. 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. 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 subsequently approved by the Idaho Commission.

US Magnesium

Q. Please explain the proposed adjustment.

A. Mr. Hayet proposes to modify the Company's modeling of the US Magnesium QF contract included in the original filed net power costs, to incorporate a recent settlement agreement for the contract. The proposed adjustment would reduce net power costs by $2.7 million.

Q. Do you agree with the proposed adjustment?

A. Yes. I agree that the recently signed US Magnesium QF contract should be included in adjusted net power costs. I do not agree with some of Mr. Hayet's modeling assumptions. At the same time, I believe the new US Magnesium Interruptible Electric Service and Operating Reserves agreements should also be included in adjusted net power costs so the expected benefits can be passed to customers.

Q. Apart from the inclusion of the two new contracts, please explain the modeling assumption differences.

A. The modeling of the QF contract is identical except Mr. Hayet assumed the project will deliver 27 MW of energy during all hours. Based on the Company's discussions with the developer, the Company expects US Magnesium to deliver

33 MW on peak and 22 MW off peak.

Q. Please explain the operating reserve and interruptible contracts.

A. The operating reserve contract is a five-year agreement commencing January 1, 2005 and providing 95 MW of non-spin operating reserves for up to 100 hours per year. The price for the operating reserves is $1.59 per KW-month. The interruptible electric service contract is also a five year agreement commencing January 1, 2005 that allows the Company to curtail 85 MW from June through September for four consecutive hours between 12:00 noon and 8:00 pm and December through January for four consecutive hours during either 6:00 am - 11:00 am or 4:00 pm – 8:00 pm.

Q. What is the impact of the Company's proposed revisions?

A. The inclusion of the recently completed stipulation and the Company's proposal to include the operating reserve and interruptible electric service agreements would decrease net power costs by $1.83 million.

Kennecott / Tesoro

Q. Please explain the proposed adjustment.

A. Mr. Hayet proposes to incorporate two new QF contracts that have been executed since the Company's original filing. The proposed adjustment increases net power costs by $1.2 million Total Company.

Q. Please explain the contracts.

A. The Kennecott contract has a fourteen month term that started on October 1, 2004 and calls for deliveries up to 31.8 MW. The Tesoro contract has a 14.5 month term that started on October 1, 2004 and calls for deliveries of up to 10 MW.

Both contracts are priced at 93 percent of Palo Verde (PV) price and have an option of two annual contract extensions starting January 1, 2006.

Q. Do you agree with the proposed adjustment?

A. I agree that the new QF contracts need to be included in adjusted net power costs. However, I do not agree with Mr. Hayet's proposed modeling.

Q. Please explain the problems with Mr. Hayet's Kennecott modeling.

A. Mr. Hayet modeled the Kenecott contract for only 10 months of the test period starting June 1, 2005 through March 31, 2005, when the contract commenced on October 1, 2004. I believe this is highly unlikely since the project will need to run to maintain its QF status. The Company's modeling starts the contract on October 1, 2004 and assumes that the project will make deliveries to the Company through the entire test period.

Q. Please explain the problem with Mr. Hayet's Tesoro contract modeling.

A. Mr. Hayet assumed Tesoro will deliver only 6 MW under its contract. Based on discussions with the project developer, the Company expects delivery to be 10 MW. The inclusion of both contracts increases net power costs by $1 million.

Thermal Deration Factor Adjustments

Q. Will you be addressing all of Mr. Falkenberg's proposed thermal deration adjustments?

A. No. I will discuss the Company's Commission-adopted method for thermal forced outage rates and address the adjustments proposed for Hunter 1, CT outage rates, Blundell, Hayden 1 and Colstrip 4. Mr. Woolley is addressing the proposed Jim Bridger 4, Hunter Transformer and other Company error outage adjustments.

Q. Please explain the Company's Commission-adopted 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. The Utah Commission reaffirmed the Company's use of this method in the order adopted for Docket No. 01-035-01, dated September 10, 2001. This method amortizes outages over a four-year period to reduce 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.

Q. Do you have any general comments regarding Mr. Falkenberg's criticism of the Company's thermal operations?

A. Yes. I believe it is misplaced. Due to the aging of the Company's generation fleet, the performance of the Company's plants has declined somewhat in recent years. Nonetheless, as discussed by Mr. Woolley, the Company's record is still excellent, as demonstrated by comparisons of thermal availability and forced outage rates to national averages. As presented in Mr. Woolley's testimony, these comparisons show that the Company's performance exceeds the national average. The outage adjustments proposed by other parties in this case should be rejected.

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 was complimentary of the

Company's method. In that docket he testified that:

> This procedure effectively allowed for a four-year amortization of major outage. 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**.**

Hunter 1 Outage

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 for which Utah ratepayers have previously paid. He also believes the Company's modeling double counts costs related to the outage. The proposed adjustment would reduce the Company's net power costs by $1.3 million.

Q. Do you agree with the proposed adjustment?

A. No. Mr. Falkenberg's reasoning is flawed and the adjustment is inconsistent with the recovery the Company received as a result of the Stipulation in Docket No. 00-035-23.

Q. Please explain.

A. The Company's outage rate modeling for Hunter 1 removed the impact of the catastrophic outage by using only the 42 month portion of the 48-month historical outage data that did not include the catastrophic outage. This modeling assumes that had the catastrophic outage not occurred, other outages would have occurred at a rate equal to the level that occurred during the 42 month period. Despite Mr. Falkenberg's assertion, the Company completely reversed the impact of the

Hunter 1 catastrophic outage and thus no double counting is involved. In comparison, Mr. Falkenberg's modeling assumes that had the Hunter 1 catastrophic outage not occurred, there would not have been any outages or maintenance derates during that 6 month period. This assumption is highly speculative and unlikely. Further, as I explain below, Mr. Falkenberg's proposal would not allow the Company to recover any of the normal cost of the outage.

Q. Please explain why Mr. Falkenberg's adjustment is inconsistent with the recovery granted the Company in Docket No. 00-035-23.

A. The stipulated recovery allowed the Company to recover a portion of the excess net power costs that were incurred during the energy crisis, based on a comparison of actual net power costs to the level being recovered in rates. The stipulation addressed the issue of the extraordinary prices paid by the Company to replace the power in the wholesale market, given the unprecedented prices in the market during the Western energy crisis. The stipulation did ***not*** provide any recovery for the outage based on normal market prices as would be recovered during a general rate case.

Q. Is the Company's modeling unreasonable and opportunistic as Mr. Falkenberg states?

A. Not at all. In fact, the Company's modeling is conservative because the Company is assuming that the outage did not occur and the outage level would be equivalent to the 42 month period that excludes the catastrophic outage. This produces a much lower outage rate than it would be if the catastrophic outage were included in the outage rate.

Q. What is your recommendation for this adjustment?

A. The Commission should reject Mr. Falkenberg's proposed adjustment because his assumptions are wrong. The Company's Hunter 1 outage modeling is conservative and does not double-count outage costs the Company recovered as a result of the stipulation in Docket No. 00-035-23. On the other hand, Mr. Falkenberg's proposed adjustment is highly speculative and unreasonable because it would not allow the Company to recover any normal costs related to the outage as is routinely allowed in general rate cases.

CT Forced Outage Rates

Q. Please explain the proposed adjustment for CT forced outage rates.

A. Ms. Coon and Mr. Falkenberg propose to use the mature outage rates for the Gadsby and West Valley CT unit instead of using the actual normalized outage rates proposed by the Company. They believe it is reasonable to ignore the initial years of actual operation of the CT unit when they typically have higher forced outage rates. Ms. Coon's proposed adjustment would reduce net power costs by $0.2 million Total Company. Mr. Falkenberg's proposed adjustment would reduce net power costs by $0.8 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. However, as pointed out by Ms. Coon, the Company's original filed NPC had a mathematical error in the 48-month average. This error has been corrected in the Company's adjusted net power costs.

Q. Is the Company's use of a mature forced outage rate for Currant Creek in proposed net power costs consistent with its approach for Gadsby and West Valley?

A. Yes. The Company is using mature outage rates at this time because Currant Creek has not been placed in service and there is no historical information. Once historical information is available for Currant Creek, it will be included in the 48-month average consistent with our treatment of Gadsby and West Valley.

Q. Do you agree with the proposed adjustments?

A. No. The adjustments are not consistent with the Commission's authorized treatment for forced outage rates. In Docket No. 01-035-01, the Company's longstanding use of a 48-month rolling historical average for thermal forced outage rates was reaffirmed. The Company's methodology does not assume that the initial operation outages will continue to occur; it merely 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 11.78 percent through December 2003, while industry data was 11.80 percent. The Company's average Equivalent Availability Factor for these units for the same period was 93.97 percent, while industry data was 82.15 percent. Thus, the Company's performance has been better than the industry average and the performance of these units has continued to improve. The outages are not extraordinary or unusual but are in fact reasonable and, therefore, the proposed adjustments should be rejected by the Commission.

Blundell Deration

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 $0.16 million Total Company.

Q. Do you agree with the proposed adjustment?

A. No. The Company's outage rate methodology does not assume the outage was never addressed and will recur indefinitely, as erroneously stated by Mr. Falkenberg. The Company's 48-month rolling average outage rate modeling amortizes outages over a four-year period to smooth the net power cost impact on customers. Once the outage is amortized there is no further impact on customers.

Q. Is the outage abnormal, as suggested by Mr. Falkenberg?

A. No. It is important to remember that thermal generation units are mechanical units that are run under extreme pressures and, as a result, components occasionally break and units incur forced outages. Also, just because a certain type of outage has not previously occurred does not mean it was abnormal, and certainly is not justification for removing the outage. Removal of these types of outages would only deprive the Company of an opportunity to recover its prudently incurred costs. The Company's modeling is consistent with the Commission's adopted methodology for forced outages and therefore, the proposed adjustment should be rejected.

Hayden 1 and Colstrip 4 Outages

Q. Please explain the proposed adjustments.

A. Mr. Falkenberg proposes to remove an 1815 hour outage at Hayden unit 1 and a 389 hour outage at Colstrip unit 4 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. He also believes recovery of the Colstrip 4 outage amounts to double counting because it occurred during the energy crisis. The proposed adjustments would reduce the Company's net power costs by $1.0 million Total Company.

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

A. No. His reasoning is quite a stretch. While it is true that the Company proposed those adjustments in UE-134, that methodology was abandoned by the Company because we determined it was not consistent with our four-year rolling average method. In fact, the methodology suggested in UE-134 was not used in our last round of general rate cases (Oregon UE-147 and Wyoming Docket No. 20000-EP-04-211). It should be noted that the adjustments were not proposed by any of the parties in those proceedings, including Mr. Falkenberg. So, Mr. Falkenberg's reasoning is not valid and his adjustment should be rejected by the Commission.

Q. Has the Utah Commission previously found that it was reasonable to include long maintenance and outage periods in rates?

A. Yes. In Docket No. 01-035-01, Mr. Falkenberg proposed to remove an unusually long outage from the Company's four year average because he considered it to be abnormal and nonrecurring. The Commission rejected the proposed adjustment. The order stated:

> We will not accept the proposed adjustment. Data on maintenance reveal that a large number of maintenance hours is not unusual. For example, the Hunter 3 outage in 1998 underwent 2,479 hours of maintenance, and Hayden 1, also in 1998, had 2,430 hours. All other outages in the years from 1994 to 1999 were less than 1,800 hours. At the other extreme, there are instances during 1995 and 1996 when no hours of maintenance are recorded at some units. Thus, maintenance data reveals unexplained high and low numbers. We also observe that the year in which the Cholla outage occurred has the lowest total number of maintenance hours of any year of the four year period 1996-1999. Thus the inclusion of Cholla does not undermine our objective of obtaining a normal number of maintenance hours from this calculation. Insofar as four-year averages have been used in prior dockets, the large number of maintenance hours associated with the 1996 Cholla outages and those mentioned of somewhat shorter but still long duration have been included in prior net power cost calculations. We therefore conclude that maintenance data for the relevant period provide no real reason to eliminate the Cholla outage.

This decision, coupled with the fact that the Company's thermal operations exceed the national average, certainly provides a sound basis for rejecting the proposed adjustments**.**

Q. Do you agree that inclusion of the Colstrip 4 outage would result in a double count because it was reflected in the costs recovered during the excess power cost deferral period from May to September 2001?

A. No. As I previously discussed, the Utah stipulation on excess net power costs allowed the Company to recover a portion of the Company's excess net power costs. It did not provide recovery for the amount of net power costs that would be normally recovered through the 48-month average during periods of normal prices. All that the Company would recover in this case is the 48-month amortization during a period of normal prices. Therefore, the Company is not double counting the outage, contrary to Mr. Falkenberg's contention. For this and the reasons explained above, the adjustment should be rejected.

Wind Shape Modeling

Q. Please explain the proposed adjustment.

A. The forecast of Foote Creek generation included in the Company's original filing was based on a seasonal shape. Within the seasonal shape, it did not have a daily shape. Mr. Falkenberg claims there is a predictable daily shape and proposes to incorporate a daily shape that he developed. The proposed adjustment would reduce net power costs by $.03 million.

Q. Do you agree with the proposed adjustment?

A. I agree with his reasons for the adjustment, but not his calculation of the adjustment. The Company's forecast of Foote Creek generation was based on the project's original projections. That information should be updated to reflect actual performance of the plant consistent with Mr. Falkenberg's proposed adjustment to update Fort James generation. In addition, Mr. Falkenberg's adjustment is incomplete.

Q. Please explain why the adjustment is incomplete.

A. The analysis developed a daily shape using historical generation and reshaped the original forecast outside of GRID. The adjustment is calculated as the difference between the market value of the Company's season-shaped generation and Mr. Falkenberg's daily-shaped generation. To be complete, two adjustments should be applied prior to applying the daily shape. First, the forecasted annual MWh hours should match the historical generation that Mr. Falkenberg used to develop his daily shape. Second, the amount of Foote Creek generation that is sold to BPA should be removed, because it is delivered to BPA with the same shape as the generation. Also, as demonstrated in the Company's Foote Creek adjustment, the adjustment can be made without resorting to a revenue calculation adjustment outside of GRID.

Q. Please describe the adjustment.

A. The Company's forecast of the Foote Creek generation is based on the project's average capacity factor for the 48-month period ending September 30, 2004. The capacity factor is used to develop a seasonal/daily shape for both the Foote Creek generation and the BPA wind sale. The seasonal daily shape is developed from a wind profile from the Energy Information Administration (EIA) within the Department of Energy. This method does not require a revenue calculation adjustment outside of GRID, as Mr. Falkenberg's adjustment does. For the above reasons, Mr. Falkenberg's adjustment should be rejected and the Company's adjustment should be adopted. This adjustment and correction of Mr. Falkenberg's proposed adjustment changes the adjustment from a $.03 million net power cost reduction to a $.51 million increase.

Q. Was Mr. Falkenberg previously advised of the existence of the EIA information?

A. Yes. The EIA wind profile was made available in the November 2004 technical conference referred to in his testimony.

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

A. As shown on Exhibit UP&L___ (MTW-1R), the Company's adjusted proposed net power cost is $745.56 million Total Company compared to the $745.2 million included in our original filing. As I discussed above, the study includes adjustment and corrections for factors such as new contracts, historical experience, and adjustments proposed by other parties which the Company has adopted. These net power costs should be used as the starting point if the Commission decides to update some of the other parties' adjustments.

Q. Does this conclude your rebuttal testimony?

A. Yes.