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

A. Yes.

Introduction

Q. What is the purpose of your testimony?

A. I will rebut:

- Messrs. Falkenberg and Chalfant's proposed adjustments for short-term firm and non-firm sales and purchase prices;
- Mr. Chalfant's proposed adjustment for short term market activities;
- Mr. Falkenberg's proposed adjustments for losses on short-term purchases and sales, thermal availability, capacity rating and spinning reserve issues, SMUD, Cholla outage and transmission;
- Ms. Wilson's net power cost testimony;
- Mr. Hayet's testimony on transmission;
- Mr. Herz's net power cost testimony on thermal availability and thermal plant maintenance; and
- Mr. Yankel's net power cost testimony on his proposed Deseret supplemental and WAPA I and WAPA II wholesale sales adjustments.

In doing so, I will demonstrate that their proposed adjustments should be rejected or adjusted. In addition to my rebuttal of the proposed net power cost adjustments discussed above, Mr. Watters will address the prudence of the wholesale sales discussed by Ms. Wilson, Mr. Yankel and Mr. Anderson, and Mr. ~~Getzelman~~ Larsen will address coal cost issues raised by Mr. Burrup.

General

Q. What is the Company's overall net power cost proposal for this case?

A. The Company's original filed net power costs were $812.6 million on a Total Company basis. On June 8, 2001 the Company filed corrections to the Company's filed net power cost results for Utah loads, Colstrip 3 and 4 capacity ratings and the longer term San Diego sale, with all parties in the case. These changes were the result of discussions with various parties in the case and the Company's review of discussions in other proceedings. Based on these changes, the Company's corrected net power costs for the 12-month period ended September 30, 2000 are $835.2 million on a Total Company basis. A summary of the revised net power cost results is provided as Rebuttal Exhibit UPL__.1R (MTW-1R). In addition, based on the continuing review of various parties' testimony, the Company discovered a few additional corrections and adjustments that should be made to the Company filed net power costs. The corrected and revised items include the following items: Spinning Reserves, Deseret Supplemental, and transmission modeling. A discussion of each of these changes is included in my following testimony. The Company's final proposed net power costs for the twelve months ended September 30, 2000 test year are approximately $806 million on a Total Company basis. The revised net power costs are included as Rebuttal Exhibit UPL__.2R (MTW-2R).

Q. Please explain the Utah load correction included in the June 8, 2001 filed corrections.

A. The consultant hired by the United States Executive Agencies, Mr. Herz, informed the Company during model discussions that it had a load error in its net power costs model. The load data that was used to balance the Company's system included 1999 Utah loads instead of twelve months ended September 30, 2000 loads. This correction reduces the Company's net power costs by approximately $20.4 million on a Total Company basis.

Q. Please explain the Colstrip capacity correction included in the corrections filed June 8, 2001.

A. During the testimony phase of the Company's Oregon UE 116 process it was determined that the Company was using an old capacity rating of 70 MW each for Colstrip units 3 and 4 instead of the current ratings of 74MW each. The issue was also raised in Mr. Falkenberg's and Mr. Herz's direct case testimony. This correction lowers net power costs by $6.6 million on a Total Company basis.

Q. Please explain the correction related to the San Diego Gas and Electric wholesale sale included in the corrections filed June 8, 2001.

A. During the Company's UE 116 case in Oregon, the Company discovered that it had inadvertently included the 100 MW long-term firm San Diego wholesale sale in the short-term firm sales category. Short-term firm transaction prices were adjusted to reflect the annualized effect of increased market prices the Company experienced during the test year. This adjustment is not appropriate for the San Diego contract because the sale is a series of four one-year contracts that were all signed on March 24, 1987 at a fixed price of $16.45 per MWh and run through the end of 2001. In other words, it is a intermediate-term firm wholesale sales contract and should be treated as such. Another similar contract, Springfield II, is already treated that way by Ms. Wilson, Mr. Anderson and Mr. Yankel. As a matter of fact, Mr. Anderson and Mr. Chalfant are treating the San Diego sale as intermediate term (longer-term) also. These contracts are also treated as intermediate term contracts in the Company's net power cost study. Further, this treatment is consistent with the treatment adopted by the Commission in Docket No. 99-035-10 for other similar contracts, such as the ESI, Hinson and Plains Electric wholesale sales contracts. This correction increases the Company's net power costs by approximately $49.6 million on a Total Company basis. The San Diego contracts are included as Rebuttal Exhibit UPL__.3R (MTW-3R).

Q. Does your testimony include a discussion of the Spinning Reserve, Deseret and transmission modeling corrections mentioned above in your testimony?

A. Yes. Those items are included in the relevant sections of my following testimony.

Q. How do actual power costs for 2000 compare with the level now proposed by the Company?

A. During 2000 the Company experienced significantly higher purchased power prices as a result of the western energy crisis. As a result, 2000 actual net power costs were approximately $833 million on a Total Company basis compared to the Company's current proposed net power costs of $806 million, or almost double the amount included in rates.

Q. Does the Company expect net power costs to decline substantially from these levels during 2001?

Q. No. Actual net power costs for the first four months of 2001 totaled $372 million. On an annual basis, the Company's 2001 net power costs were forecasted to be approximately $760 million on a Total Company basis in a February 2001 forecast. However, it should be noted that FERC recently placed a cap on wholesale energy prices that has resulted in much lower market prices today and through the remainder of the year, based on current expectations. Unfortunately, the Company's previously executed forward purchases are now higher priced than the current forward price curve. This has effectively eliminated the prior expected benefits of the Company's forward purchases, which had the effect of driving the lower expected net power costs for the second half of 2001, referred to by Mr. Falkenberg on page 10 of his testimony. As a result, the Company now expects net power costs to be substantially higher than the $760 million previously forecast.

Q. There are a large number of proposed adjustments, many of which affect the outcome of other adjustments. How do you recommend the Commission treat these items?

A. Because of the multiple parts of some adjustments, some of which may be adopted and the interrelationship of some adjustments with other adjustments, I believe it will be necessary for the Commission to require a final net power cost run that incorporates Commission adopted adjustments to insure a clear record.

Short-Term Firm and Non Firm Sales and Purchase Prices – Falkenberg, Chalfant

Q. Mr. Falkenberg describes the Company's market price adjustment as "hubris" and proposes a $126.9 million adjustment to the Company's net power costs. Mr. Chalfant of UIEC states that the Company's price adjustments are imprecise and proposes a$101.6 million adjustment to the Company's net power costs. Do you have any general comments?

A. Yes. The Company believes the annualized market price adjustment for short-term firm and non-firm price increases included in its filing is consistent with historical ratemaking treatment the Company has received in the state of Utah. For example, if a wholesale contract has a price change at some time during the test year, the change is typically annualized to the beginning of the test year in the net power cost study. Similarly, if a contract terminates during the test year, the termination is annualized to the beginning of the test year. Following that same logic, the Company annualized the significant wholesale market price increases that affected the Company and the rest of the WSCC since spring 2000.

Q. Mr. Falkenberg states that "the Company's method is the antithesis of a 'known and measurable' change." Do you agree with this statement?

A. No. It seems that Mr. Falkenberg is taking issue with whether an actual change in costs can be viewed as known and measurable. The high market prices incurred during the test year are certainly known to the entire WSCC. The impact of the high market prices is certainly measurable also. As shown in my direct testimony, 2000 market prices are drastically higher than 1999 market prices, and they did not decline after the end of the test period. As a matter of fact, market prices were substantially higher after September 30, 2000 than those included in the Company's case. Mr. Falkenberg is not consistent when he suggests that the lower market prices that occurred at the beginning of the test period are more appropriate, while at the same time stating that "it is quite questionable as to whether 'normal' conditions actually exist anymore. … It may be some time before the market returns to a state of surplus and attendant lower prices."

Q. Is the Company's market price annualization forward looking?

A. Not at all. As I explained previously, the adjustment merely annualizes cost increases the Company incurred during the historical test year.

Q. Please explain how the Company annualized the wholesale market price increases the Company experienced from June 2000 through September 2000 for the period October 1999 through May 2000.

A. The Company's market price annualization included several steps, which are outlined below:

First, the Company calculated the monthly average for each month from the year of inception to year-end 1999 for each index (Mavg).

Second, the Company calculated the 12-month average of the above monthly averages (Aavg) and the average of June through September (JSAvg), and the ratio of the June-September average over the annual average (Ratio = JSAvg / Aavg).

Third, the Company calculated the average actual prices for the period June 2000 through September 2000 (JSavg2000). The annualized average price (Aavg2000) for 2000 is determined by dividing the ratio developed above into the actual average price for June-September 2000: (Aavg2000= JSAvg2000/Ratio).

Fourth, the annualized monthly prices (MP) for the period October 1999 through May 2000 are determined from the annual average price (Aavg2000) for 2000 multiplied by the monthly average index price (Mavg), divided by the annual average (Aavg). (MP = Aavg2000 * Mavg / Aavg)

Q. How do you respond to Mr. Falkenberg's claim that the Dow Jones Indices that the Company used to develop the annualized market prices may not be good reference points?

A. The Dow Jones electricity price indexes are calculated summaries of transactions that occurred at the major market hubs, and are widely used by the participants in the electricity market. The calculations of the indexes may not include all the transactions that occurred in the market. However, the calculations are representative of all transactions, and are not based on selected transactions or transactions of a limited number of participants. Mr. Falkenberg may not be "questioning whether the Dow Jones index represents a reasonable effort to develop an index." But he seems to be quick at questioning the ability of the participants to "accurately reveal all of the pertinent information." I must point out that Mr. Falkenberg's claims are conclusory in nature, and are not supported by sufficient explanation or demonstration to have much probative value.

Q. Both Mr. Falkenberg and Mr. Chalfant indicate that the Company used only four months of data to develop the annualized market prices. Do you agree with this description of the Company's methodology?

A. Not entirely. As shown in Mr. Falkenberg's Attachment RJF No.1, the Company used the entire history of the indexes since their inception, except year 2000, to develop the monthly shape of the prices. The annualized market prices for the test year were determined based on that shape and the prices in the months (June-September) that showed significant price increases during the test period. However, I am not aware of any requirement on how many data points are needed for annualizing known and measurable changes. As I discussed earlier, if a contract has a price change in the last month of the test period, the change is typically annualized to the beginning of the 12-month test period. A copy of Attachment RJF No. 1 is provided as Rebuttal Exhibit UPL__.4R (MTW-4R).

Q. Mr. Falkenberg questions whether the Dow Jones Indices roughly approximate the prices the Company actually experienced in the market. How do you respond to this claim?

A. The Company is a buyer and seller in the market as are other participants in the WSCC market. Market prices have been transparent to all participants since the market opened up several years ago. Certainly not every transaction the Company carries out is at the index price, but the index shows the general condition of the market and the Company trades in that market and can not dictate more advantageous prices without losing transactions to other parties.

Q. Mr. Falkenberg points out that the Company ignored market price differences between firm and non-firm products that is stated and recommended in the Commission Order in Docket No. 99-035-10. Is this a valid criticism?

A. No. The Commission Order in Docket No. 99-035-10 states that the Committee claims that the "firm service has more value than non-firm service," and therefore "short term firm prices should be higher than non-firm prices." However, the Committee never provided any support for such a claim and a review of market prices for the last year shows that firm prices are generally higher than non-firm prices, but not always. Frequently, buyers enter firm transactions to insulate themselves from price spikes in the non-firm market. The claimed relationship between firm and non-firm is far from certain. In addition, the volumes of the short-term firm transactions are significantly higher than non-firm transaction volumes. As a result, the firm indexes are statistically more significant.

Q. Both Mr. Falkenberg and Mr. Chalfant state that the Company would not make the same short term firm sales and purchases if the higher market prices were in place. Do you agree?

A. No. The short term firm transactions that the Company makes may not be the same from one period to another. But the needs to supplement its resource portfolio and the opportunities to generate wholesale revenue would still be there regardless of market prices for that same historical period. To annualize price changes of a contract, only the prices are changed, although the energy amount may be different. Messrs. Falkeberg and Chalfant do not seem to think prices impact volumes when they propose their adjustments for so-called losses on short-term purchases and sales. Mr. Chalfant sites the changes in purchases and sales from November and December 1999 to November and December 2000 and claims that they are attributed to the Company's response to the market prices. Apparently, Mr. Chalfant has not recognized the changes that affected the November and December 2000 transactions. Those changes include poor hydro conditions, severe winter weather in December, the sale of the Centralia plant in May 2000, the outage of the Hunter #1 unit starting in November 2000, and the changes in the Company's other load obligations and long-term resources.

Q. Mr. Chalfant states on page 3 of his testimony that it does not appear that the Company's annualized market prices make any attempt to use the timing of the Company's purchases and sales to develop properly weighted monthly average prices. Is this correct?

A. No. The Company used peak and off-peak splits from the test period to develop the weighted monthly average prices that are used as inputs to the model.

Q. On page 5 of Mr. Chalfant's testimony, he states that it is not "obvious whether these subsequent price changes had a negative or positive impact on PacifiCorp's costs and revenues, for example, because, they may have had a greater impact on sales than purchases and, as a result, increased revenue more than costs". Does this reflect the Company's actual experience?

A. No. As I discussed above, high market prices have driven the Company's net power costs up substantially. For example, the adopted net power cost in the

Company's 1998 Utah rate case were approximately $426 million on a Total Company basis compared to $833 million on an actual basis for 2000. Of these costs, approximately $68 million are for replacement power purchases for the Hunter outage. Nonetheless, it is still obvious that high market prices have had a negative impact on the Company, even though prices weren't high for the entire year.

Q. Is it more appropriate to use actual prices in the current proceeding when the market has departed so drastically from price levels experienced prior to June 2000?

A. No. The method that the Company used to annualize known increases in market prices may not be perfect. However, given the information available to the Company, the method captures the logic of annualizing known and measurable changes, and captures reasonably well the magnitude of the changes. Assuming the same market prices that existed prior to June 2000 will be known and representative for the period rates will be in effect is a blunt denial of reality.

Q. On page 27 of Mr. Falkenberg's testimony, he suggests that the Commission will be reversing precedent if it adopts the Company's price normalization procedure. Do you agree?

A. No. As I explained above, the Company's market price adjustment is an annualization of actual wholesale market price increases; it is not a normalization adjustment. To the best of my knowledge, the Commission has historically adopted annualization of known changes that occurred during the test period.

Therefore, acceptance of the Company's market price annualization proposal would be consistent with Commission precedent, not a departure from it as Mr. Falkenberg suggests.

Q. Is Mr. Falkenberg's alternative recommendation to remove the impact of wholesale contracts that expired after the test period consistent with Utah regulatory practices?

A. No. In the Company's last several rate cases, the Commission has strictly adhered to a historical test period and accordingly has excluded out of period adjustments from adopted results. For example, in Docket No. 99-035-10, the Commission did not allow the Company to begin recovery of Dave Johnston mine closure costs because the mine was fully operational during the test year. Mr. Falkenberg's proposal to remove wholesale contracts expiring after the end of the test year is just that: an out of period adjustment proposal.

Q. If Mr. Falkenberg's proposal is adopted, would it be necessary to adopt other adjustments to maintain a balance between revenues and expenses?

A. Yes. As Mr. Watter's explained in his rebuttal testimony, load growth has also been a factor in the Company's increased net power costs. Therefore, at a minimum, the Company's retail loads and allocation factors should also be updated to reflect the level in effect during the period of Mr. Falkenberg's proposed adjustment in order to maintain a proper matching of revenues and expenses.

Q. What is your position on Mr. Falkenberg's alternative recommendation to reduce net power costs for post test period expiring wholesale sales contracts?

A. The Commission should reject the proposed adjustment because the contracts were in effect during the test period and their elimination would create a significant mismatch between revenues and expenses.

Q. Mr. Chalfant suggests that the Company should file a rate case "after it has data that fully reflects what it argues are long-term changes in market prices, rather than to make incorrect adjustments to historical data." Do you agree?

A. No. As discussed by Ms. Clark, the significant cost increases experienced by the Company from high market prices have caused the Company to suffer credit and liquidity problems. Therefore, Mr. Chalfant's suggestion that the Company should wait for a test year that fully reflects higher market prices is not a reasonable solution.

Q. What is your recommendation to the Commission regarding the use of the annualized market prices?

A. The Commission should reject the adjustments proposed by Messrs. Falkenberg and Chalfant on the basis that annualization of known and measurable changes is part of the ratemaking process, and the annualization of the known changes in wholesale market prices is really no different from annualization of a contract price change.

Short Term Market Activities - Chalfant

Q. Please describe Mr. Chalfant's proposed adjustment for short-term market activities.

A. Mr. Chalfant proposes to reduce the Company's net power costs for perceived losses on short-term firm and non-firm sales and purchase transactions he calculated, based on an hourly model he developed. The adjustment would reduce the Company's net power costs by $47.4 million on a Total Company basis.

Q. Do you agree with the proposed adjustment?

A. No. Although I agree conceptually with his proposal to measure the profitability of the transactions on a comparable basis, I do not agree with the proposed adjustment as calculated.

Q. Please explain.

A. On page 10 of his testimony, Mr. Chalfant recognized that it is imperative to compare relevant sales and purchase transactions on a comparable basis, not on a monthly or annual aggregated basis, to achieve a valid comparison. Specifically, he stated the following:

> "It is critical to avoid time-related differences in comparisons of costs and revenues to be assigned to the power marketing function. For example, it would not be reasonable to compare a purchase made on a summer afternoon with a price of $10 per MWh to a sale that was made on a winter night with a price of $3 per MWh and conclude that the Company lost $7 on that pair of transactions. In fact, the Company may have been selling for $12 per MWh at the same time the $10 per MWh purchase was made, and purchasing for $2.75 per MWh at the same time the $3 sale was made.
>
> Using aggregate annual or monthly data on short-term sales and purchases implicitly involve such comparisons. Specifically, if purchases tend to occur more heavily during hours when market prices are high and sales tend to be made at hours when market prices are low, then comparing

> average sales and purchase prices may not give an accurate picture of whether the Company's marketing activities are profitable".

Q. Does Mr. Chalfant's proposed adjustment adequately calculate the profitability of the Company's market trading activities?

A. No. Despite Mr. Chalfant's effort to consider timing differences between transactions, his analysis does not adequately calculate the profitability of short-term transactions. There are five major changes that should be made to Mr. Chalfant's proposed adjustment to correct the inadequacies of his analysis. First, actual non-firm transactions should be excluded since retail rates are set on the basis of normalized non-firm sales and purchase transactions calculated by the Company's net power cost model. Second, Mr. Chalfant's proposed adjustment used October, November and December 2000 data in place of the same monthly data for 1999, which are part of the test period. The October-December 2000 information is outside the test period, is not consistent with the rest of the Company's case, and therefore is not valid for use in this case. Third, the transactions should be reviewed based on the time they were executed in addition to an hourly comparison, because balancing the system is a continuous long-term process and market prices fluctuate from hour to hour, day to day, and month to month. Therefore, just comparing transactions on the delivery hour does not present an accurate comparison. Fourth, the transactions should be compared on a like-kind product basis. Fifth, the transactions should be compared on a similar location basis because of transmission constraints that exist in the Company's system.

Q. Have you revised Mr. Chalfant's analysis to reflect your proposed changes?

A. No, I have revised Mr. Chalfant's analysis only in part, since we have not been able to get his model to work. The Company requested a working version of the model so we could test the model and make appropriate changes if necessary, but we were provided a version that is not compatible with Company software. As a result, the only correction I was able to make was to replace the October – December 2000 data with the appropriate test period data from 1999. This partially revised analysis, which is summarized as Rebuttal Exhibit UPL__.5R (MTW-5R), reduces Mr. Chalfant's proposed adjustment to $33 million on a Total Company basis. However, it should be noted that the correction produced by this revised analysis is incomplete because it still includes actual non-firm transactions, assigns the highest priced purchases to wholesale marketing and does not compare STF transactions on a date completed, comparable location or comparable product basis.

Q. Why is it so important to consider the date the transactions are completed?

A. The process of balancing the Company's system is a complex, ongoing process that starts well in advance of the actual delivery time. During the time leading up to delivery, the Company's load and resource balance can change frequently (higher or lower) due to a number of factors. Those factors include higher than expected retail load growth, unit outages, weather and hydro conditions. The Company generally makes both sales and purchases in advance of real time in an effort to keep loads and resources in balance at the lowest possible cost. Because of this, it is imperative that transactions executed six months ago for delivery today are not compared with purchases executed very recently. For example, in December 1999 the Company expected a 300 aMW short position for July 2000 based on the load and resource balance. To cover the shortfall, the Company prudently bought 300 aMW to balance the forecast position at then current market prices. Six months later, however, the Company's loads and resource situation changed, and the Company than anticipated a long position for July. Unfortunately, by that time, the region is also long, which causes market prices to drop. Nonetheless, because the Company found itself in a long position, it prudently sold energy at market prices that were now lower than the December 1999 purchases. In this situation, unless the timing of the prudent transactions are taken into consideration, it will appear that the Company sold energy at a loss. In reality, both transactions were prudent because they were executed at market based upon expectations at the time of the transactions. The Company believes this approach to balancing its system is prudent and much better than the alternative approach, which leaves the bulk of system balancing to the very volatile day ahead and real time markets, as was previously done in the failed California deregulation attempt. Accordingly, it is essential that execution dates are taken into consideration as well as delivery time differences.

Q. Is the intermediate-term San Diego wholesale sale a good example of differences in execution dates and product types?

A. Yes. The San Diego wholesale sale contract is a perfect example of a transaction that is not comparable to transactions made during the test year and should be excluded from the STF profitability analysis. The sale was made on March 24, 1997 for a four-year period from January 1998 through December 2001 at then prevailing market price expectations. It is clearly not reasonable to compare a transaction that was executed in March 1997 to a purchase transaction executed sometime in 2000.

Q. Did Mr. Chalfant treat the San Diego wholesale sale appropriately in his analysis?

A. Yes. Mr. Chalfant treated the sale as an intermediate term wholesale sale and excluded it from his loss calculation.

Q. Please explain why it is important to take into consideration product differences in any measure of short-term profitability.

A. Because of the Company's load profile, it is difficult to match loads and resources perfectly with single transactions. As a result, it generally takes multiple transactions to balance the Company's system for a given period. For example, during a typical summer day on the east-side, the Company is generally short during the peak or super-peak periods and long during the off-peak and shoulder-peak periods. This is illustrated on page 1 of Rebuttal Exhibit UPL__.6R (MTW-6R). When the Company purchases energy to cover its short position, there are generally two impacts. First, the shortage is covered by the most valuable component of the block purchase, the super peak period. Second, the Company is put in a long position, during the lower cost shoulder hours of the peak period, because demand is lower during the shoulder hours. These impacts are illustrated on page 2 of Rebuttal Exhibit UPL__.6R (MTW-6R). In order to balance the system, the Company must then sell the lower value long position. In this example, a monthly comparison of these transactions would generally show a loss because the Company bought a higher value product to cover its short position and sold the leftover lower value product to balance the long created by the purchase that covered the short. Once again, in reality a loss was not incurred; rather, the Company merely balanced its system. This situation occurs very often in the Company's east-side system during the summer season and demonstrates why it is critical to do a more detailed analysis.

Q. Why is it also important to compare transactions on the same delivery point basis?

A. Because of transmission constraints on the Company's system, not all transactions are comparable. For example, the Company could be long on the west-side during the summer and deficit on the east-side. Transmission constraints prevent the Company from moving the entire surplus from the west-side to cover the deficit in the east. In order to balance the system, the Company must sell some energy in the lower priced west-side and buy some energy in the higher priced east-side at the same time. Once again, a comparison of those transactions would show a loss when in reality a loss was not incurred. Mr. Chalfant's compares these types of transactions in his analysis to determine profitability, when in fact they are not comparable.

Q. Can Mr. Chalfant's model be adjusted to exclude non-firm transactions and take into consideration comparable execution dates and delivery points?

A. I do not think so, although because we have been unable to get Mr. Chalfant's model to work, I cannot know for certain.

Q. Is there another alternative?

A. Yes. We can use the information from Mr. Falkenberg's loss on short-term purchases and sales analysis as a starting point and go through the process of sorting the STF transactions so that it can be analyzed on a comparable basis. Since Mr. Falkenberg's data only include east-side transactions and exclude non-firm transactions, we are part of the way there. First, as I explained above, the intermediate term San Diego sale must be removed from the results, since Mr. Falkenberg is including it as a short-term firm transaction. Then the remaining transactions must be compared on a like kind basis. In other words, the type of product, the execution dates, and delivery time of the transactions must be taken into consideration.

Q. Have you prepared such an analysis?

A. Yes. Rebuttal Exhibit UPL__.7R (MTW-7R) shows the impact of removing the San Diego Sale. Removing the longer term San Diego sale reduces Mr. Falkenberg's proposed adjustment to approximately $47.0 million on a Total Company basis. For the remainder of the analysis, I have analyzed only the June and July data because they encompass the bulk of Mr. Chalfant's and Mr. Falkenberg's proposed adjustments and are sufficient to demonstrate that the purported losses are not real. Page 1 of Rebuttal Exhibit UPL__.8R (MTW-8R) summarizes the purported June losses from Rebuttal Exhibit UPL__.7R (MTW-7R) between peak and off-peak transactions. This comparison reduces the purported losses for June from $24 million to $22.5 million or $22 million on-peak and $.5 million off-peak on a Total Company basis. Page 2 of Rebuttal Exhibit UPL__.8R (MTW-8R) summarizes the data from page 1 by delivery day and breaks the information down between gains and losses. Page 3 of Rebuttal Exhibit UPL__.8R (MTW-8R) recalculates the information from page 2 based on comparable delivery and execution dates. This shows that the purported level of losses drops to $5.9 million for on-peak transactions and $.4 million for off-peak transactions on a Total Company basis. Page 4 of Rebuttal Exhibit UPL__.8R (MTW-8R) analyzes the losses of the four purported highest loss days shown on page 3 by comparable delivery points. This analysis shows that when comparable delivery points are taken into consideration all of the purported losses occurred at the Four Corners delivery point. Page 5 of Rebuttal Exhibit UPL__.8R (MTW-8R) analyzes the Fours Corners transactions from page 4 that generated the losses. This data shows that the purported losses are reduced from over $5 million to zero when the transactions are reviewed on an hourly basis.

Rebuttal Exhibit UPL__.9R (MTW-9R) shows similar information for July. Page 1 of Rebuttal Exhibit UPL__.9R (MTW-9R) summarizes the purported July losses from Rebuttal Exhibit UPL__.7R (MTW-7R) between peak and off-peak transactions. This comparison reduces the purported losses for July to a $4.5 million net monthly gain from a $6 million monthly loss when the transactions are broken down between peak and off-peak transactions, or to a $7.3 million on-peak gain and $2.8 million off-peak loss on a Total Company basis. Page 2 of Rebuttal Exhibit UPL__.9R (MTW-9R) summarizes the data from page 1 by execution day for the off-peak transactions. This data reduces the purported off-peak losses from $2.7 million to $.8 million. Page 3 of Rebuttal Exhibit UPL__.9R (MTW-9R) recalculates the information from page 2 based on comparable delivery and execution dates and delivery points. This data shows that almost all of the purported off-peak losses were related to Four Corners transactions, as was the case in June. Page 4 of Rebuttal Exhibit UPL__.9R (MTW-9R) analyzes the Fours Corners transactions from page 3 on an hourly basis. This information shows that the purported losses are reduced from $.8 million to .05 million when the off-peak transactions from page 3 that generated the purported losses are reviewed on an hourly basis. In conclusion, the analyses from Rebuttal Exhibit UPL__.8R (MTW-8R) and Rebuttal Exhibit UPL__.9R (MTW-9R) demonstrates that when the short-term firm transactions for June and July 2000 are analyzed on a fully comparable basis, there are no material losses.

Q. What is your recommendation?

A. As I described above, Mr. Chalfant's proposed adjustment does not adequately measure the profitability of the Company's market trading activities. When the Company's market trading transactions are analyzed on a comparable basis, the analysis demonstrates the Company did not incur net trading losses. Therefore, the Commission should reject Mr. Chalfant's proposed adjustment for short-term market activities.

Losses on Short-Term Purchases and Sales - Falkenberg

Q. Please explain Mr. Falkenberg's proposed short-term loss adjustment.

A. Mr. Falkenberg's proposes to compare the average annual price of short-term firm purchases and short-term firm sales made in the Utah Division. Mr. Falkenberg assumes that there is a loss when the annual average purchase price is higher than the annual average sales price. His adjustment proposes to eliminate the purported losses by setting the monthly purchase price equal to the monthly sales price. The proposed adjustment would reduce net power costs by approximately $71 million on a Total Company basis.

Q. Do you agree with the proposed adjustment?

A. No. Mr. Falkenberg proposes a simplistic method to determine the profitability of short-term firm transactions that does not adequately measure the profitability of transactions under taken to handle the complex process of balancing and optimizing the Company's system. As Mr. Chalfant correctly observed,

> "it is critical to avoid time-related differences in comparisons of costs and revenues".

Mr. Falkenberg's proposed adjustment uses a simple average method that does not take into account time and product related differences. Therefore, it does not provide a meaningful comparison and should be rejected by the Commission.

Q. Have other witnesses beside you and Mr. Chalfant recognized the importance of the time period issue?

A. Yes. As a matter of fact, Mr. Falkenberg's colleague on behalf of DPU and CCS in this case, Mr. Hayet, has recognized this issue. On page 26 of his testimony he stated:

> "Schedules of energy, as well as the cost of that energy are typically very different depending on the time period".

Given Mr. Hayet's understanding of this issue, it is curious that Mr. Falkenberg continues to rely on the simple average method.

Q. Mr. Falkenberg's proposed adjustment for losses on short-term purchases and sales is very similar to Mr. Chalfant's proposed adjustment for short-term market trading activities. Does your rebuttal of Mr. Chalfant's testimony also apply to Mr. Falkenberg's proposed adjustment?

A. Yes. As I explained above, I used Mr. Falkenberg's proposed adjustment for losses on short-term purchases and sales as the starting point for the analysis I used in my rebuttal of Mr. Chalfant's testimony. That analysis demonstrates there are no net short-term losses when the Company's short-term firm transactions are reviewed on a comparable basis. This same analysis applies to Mr. Falkenberg's proposed adjustment and provides justification for my recommendation that the Commission reject Mr. Falkenberg's proposed adjustment.

Q. On page 27 of Mr. Falkenberg's testimony, he stated that his proposed loss adjustment would decrease the Company's proposed net power costs by $198 million on a Total Company basis if the Company's proposed market prices are used. Do you agree?

A. No. I find his suggestion rather amusing. The Company uses actual information for the months from June 2000 through September 2000, and uses annualized market prices for October 1999 through May 2000. In the annualized months, the Company uses the same monthly peak and off-peak prices for sales and purchases in respective markets. As I have discussed above, there are no net losses for the actual months. There are certainly no losses implied in the annualized months. For example, if the on-peak market price was $100 per MWh at COB for a given month, the Company uses the same price for on-peak sales and purchases. Therefore, there are no net losses for these months included in the Company's filing. Yet, Mr. Falkenberg states that losses would be even greater if the Company's proposed market prices are adopted by the Commission.~~Mr~~. Falkenberg's alternative proposed adjustment is clearly not correct for the months October 1999 through May 2000 and for June 2000 through September 2000, as I have demonstrated above. The Commission should reject Mr. Falkenberg's alternative proposed adjustment if the Company's proposed market prices are adopted.

Q. Do you have any further comments on Mr. Falkenberg's proposed loss adjustment for STF transactions?

A. Yes. I find it rather interesting that Mr. Falkenberg did not propose the same adjustment in the Company's recent Oregon UE 116 case, given the fact that the method he proposes in this case would have yielded similar results in that case.

The absence of a similar proposal in that jurisdiction strongly suggests the adjustment is of questionable validity.

Thermal Availability - Falkenberg

Q. Please explain Mr. Falkenberg's proposed adjustment for thermal availability.

A. Mr. Falkenberg proposes to change the four-year average thermal availability calculation that has been used since 1990 in Utah, to a six year average because of a claimed dramatic increase in outage rates compared to earlier years. The proposed adjustment would reduce the Company's net power costs by $15.3 million on a Utah allocated basis.

Q. Do you agree with the proposed adjustment?

A. No. As I will demonstrate, the Company's thermal performance has been and continues to be very good. Mr. Falkenberg's proposed adjustment is based on misleading accusations and data manipulation, and would result in a double count of benefits already received by Utah ratepayers. The real reason for the significant increase in net power costs is not changes in thermal generation, as suggested by Mr. Falkenberg, but is caused by the exorbitant market prices the WSCC has been experiencing.

Q. Do you agree with Mr. Falkenberg's claim on page 31 of his testimony that the Company's unscheduled outages have increased significantly?

A. No. Mr. Falkenberg's statement that the Company's unscheduled outage rates have increased by 50% from 1994 to 1999 is nothing more than a mathematical exercise using selective data. The Company's forced outage rates from 1991 though 2000 are shown on Rebuttal Exhibit UPL__.10R (MTW-10R). The forced outage rate represents the percent of time a unit is unexpectedly forced out of service. As shown, the Company's forced outage rates increased from 3.73% in 1994 to 5.63% in 1999, the period used in Mr. Falkenberg's analysis or an overall small increase of 1.90%. Of course, Mr. Falkenberg's method would divide a small number, 5.63% in 1999, by another even smaller number, 3.73% in 1994, to produce a 50% increase. On the other hand, if Mr. Falkenberg's method is modified by using 5.50% from 1993 -- just one year earlier -- and the same 5.63% from 1999, the percentage change would only be 2.3% compared to the 50% used in his testimony. Using the Company's proposed method the percentage change would only be .13% from 1993 to 1999. Thus, Mr. Falkenberg's suggested dramatic increase in unscheduled outages has more to do with the timing and presentation of information than it does about the Company's actual performance.

Q. How does the Company's thermal performance compare to the National average?

A. As shown on Rebuttal Exhibit UPL__.11R (MTW-11R), the Company's thermal availability and capacity factors have exceeded the national average for comparable sized units for nine straight years by a large margin.

Q. Have there been any dramatic changes in the Company's thermal performance as Mr. Falkenberg infers?

A. No. As shown on Rebuttal Exhibit UPL__.10R (MTW-10R) and Rebuttal Exhibit UPL__.11R (MTW-11R), the Company's thermal performance has been very good for the last 10 years and has only fluctuated within a reasonable range from year to year.

Q. Is there anything compelling about using a six-year period to develop an average for thermal availability?

A. No. Mr. Falkenberg has not presented any compelling justification. As the data I discussed above shows, the use of a six year average is nothing more than data manipulation. On the other hand, the Company has always used a rolling four-year average regardless of whether or not the availability factors have gone in the Company's favor. The purpose of a four-year rolling average is to smooth year-to-year swings in generation levels, which it does. Average thermal availability should not be revised periodically to counter balance other cost increases, such as market prices.

Q. Have you reviewed Mr. Falkenberg's Exhibit RJF/8?

A. Yes. This is another example of misleading information. Mr. Falkenberg's analysis only shows half of the picture. The analyses he prepared shows only the impact of changing thermal availability while keeping market prices the same as the Company's filed case (which, by the way, he is not proposing to use). What he should have done was also determine the impact of the changes in thermal availability with lower market prices. Rebuttal Exhibit UPL__.12R (MTW-12R) shows the current case net power cost results if 1997 and 1998 market prices are used with availability factors for each of the years 1994 through 1999, compared with the runs that Mr. Falkenberg made for the comparable years. The data clearly shows that when a lower price level is used the changes in generation levels have a limited impact on overall net power costs. For example, using the market prices from the Company's 1997 Utah stipulation shows that the difference between a four-year average and a six-year average only produces a Total Company difference of $8.1 million. Using the adopted market prices from Docket No. 99-035-10 produces a difference of $12.8 million. In comparison, Mr. Falkenberg's Exhibit RJF/8 which uses the much higher market prices included in the Company's filing, produces an $82.3 million difference between four and six-year averages. This clearly demonstrates that the main driver of the increase in net power costs is market prices, not thermal availability.

Q. Earlier you mentioned that Mr. Falkenberg's proposal would result in double counting. Please explain.

A. The stipulation in the Company's 1997 test year Utah rate case utilized a four year average for thermal availability that was based on 1994 through 1997 data. The 1998 test year rate case, in turn, utilized a four-year average for thermal availability that was based on 1995 through 1998 data. Now Mr. Falkenberg proposes to go back in time and add the 1994 and 1995 data to the current case so Utah customers can receive the benefits of the Company's excellent record of thermal availability for a second time, to provide relief during a period with much higher market prices. The Commission should not allow this to happen.

Q. On page 32 of his testimony, Mr. Falkenberg states that the Company believes there is no permanent trend in its outages. Is this an accurate statement?

A. Although his statement is technically correct, it is incomplete. The Company also stated that thermal units are mechanical units that are put under a great deal of stress through their operation and are expected to break down, although it cannot be known when it is going to happen. That is why they are unexpected single occurrence events and why we stated that there is no permanent trend. As shown on Rebuttal Exhibit UPL__.10R (MTW-10R), forced outage rates vary from year to year, sometimes up and sometimes down. Contrary to Mr. Falkenberg's claim that the Company's current outage performance is unacceptable, in reality, it is not much different than it has been over the last 10 years. The four-year average (96-99) was 4.62% and the ten-year average (91-00) was 4.48%

Q. Mr. Falkenberg discusses a modeling change recommended by Mr. Hayet that would result in multiple year runs with individual year thermal availability rates that would be averaged to determine normalized net power costs. Do you have a view on this approach?

A. Yes. It should be noted that Messrs. Falkenberg and Hayet are not proposing this methodological change for this case. In my view, the issue should not be pursued on this basis in the future either, given the time consuming modeling required to address the issue properly. Rather, the issue should be addressed in the context of a new net power cost model, on which the Company is currently working.

Q. What is your recommendation regarding Mr. Falkenberg's proposed thermal availability adjustment?

A. Given the fact that the Company's thermal plant performance has been and continues to be very good and the real driver for the increased net power costs is market prices, there is no sound justification for moving to a six-year average. Moreover, Mr. Falkenberg's proposed adjustment would result in a double counting of benefits previously received by Utah customers. The Commission should therefore reject the proposed thermal availability adjustment.

Capacity Rating / Spinning Reserve Issues - Falkenberg

Q. Please explain Mr. Falkenberg's proposed capacity rating / spinning reserve issues adjustment.

A. The proposed adjustment has three parts: (1) Wyodak capacity rating, (2) Gadsby capacity rating, and (3) spinning reserves. Mr. Falkenberg states that based on his analysis, the Company has understated the capacity of the Company's Wyodak and Gadsby plants and that the Company does not lose as much generation to spinning reserves as the Company has modeled. Based on these assumptions, he proposes to increase the generation levels for Wyodak and Gadsby and reduce the amount of spinning reserves the Company has modeled. The adjustment would reduce the Company's net power costs by $16.5 million on a Total Company basis.

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

A. No. The Company has not understated the MWh generation associated with the Wyodak and Gadsby thermal units. Nor has the Company overstated the amount of spinning reserves required for the east-side of the Company's system. As a matter of fact, the Company's net power cost modeling has, if anything, *understated* the annualized level of spinning reserve requirements.

Q. On page 40 of Mr. Falkenberg's testimony, he states that in the Oregon case, the Company conceded that the rating for Colstrip is understated in its net power cost model and the results are similar for Wyodak. Is this statement correct?

A. No. In the Oregon UE 116 case, the Company did understate the capacity ratings for Colstrip 3 and 4, because an old capacity rating was inadvertently used, as it was in this case. As I explained above, the Colstrip rating has been corrected. However, Wyodak generation levels are not understated. The Company is using the current maximum dependable capacity (MDC) rating for Wyodak.

Q. Please explain Mr. Falkenberg's proposed adjustment for Wyodak.

A. Based upon Mr. Falkenberg's review of Wyodak generation logs, he concluded that the unit exceeded the 268 MW MDC rating for more than 7000 hours during 2000. As a result, he proposes to increase the MDC rating of Wyodak by 14 MW based on the highest 500 hours of operation for purposes of modeling net power costs as part of his overall capacity adjustment.

Q. Is it reasonable to set the MDC rating of a generation unit based on the 500 highest hours of operation?

A. No. This is not a reasonable reference point, as it measures the highest output a unit has achieved for less than six percent of the hours in a year under optimal conditions. The Company sets generating units MDC at a level that represents the net generation that can be expected to be achieved on a normal ongoing basis.

This is very important from a system operation perspective because the Company needs to know how much energy can be expected under normal conditions, so an operating plan can be developed to meet load obligations in the least cost manner. If ratings were based on the 500 highest hours of generation as Mr. Falkenberg suggests, operating plans would be unreliable.

Q. Do you agree with Mr. Falkenberg's basic premise that a higher MDC rating will result in higher net output from a generation unit?

A. No. Mr. Falkenberg's assumption that higher MDC ratings equate to a higher level of net generation is wrong. Operating Equivalent Availability Factors and the MDC ratings used in the Company's production dispatch model are not independent variables, as Mr. Falkenberg's proposed adjustment suggests. Operating Equivalent Availability Factors are calculated based on each unit's MDC rating. Therefore, if the MDC rating is revised, the associated availability factor must also be revised. When the availability factor is changed to correspond with the new higher MDC rating, the result is a lower availability factor because the unit cannot achieve the new rating for the same number of hours and the result is the same net output from the unit. On this basis alone Mr. Falkenberg's proposed adjustment should be rejected.

Q. Please explain Mr. Falkenberg's proposed Gasdby adjustment.

A. Mr. Falkenberg proposes to allow the model to determine how much Gadsby should run based on historical availability factors and market prices. The adjustment is incorporated in his overall proposed capacity adjustment.

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

A. No. The adjustment is not reflective of how the Company actually operates the Gadsby units. Mr. Falkenberg's proposed modeling suggests that the Gadsby units would run at an unrealistic 63% capacity factor, which is totally out of line with actual experience. For example, during the period May 2000 through March 2001, a period with market prices higher than those included in the Company's case, the Gadsby units only ran at a 48% capacity factor or 15% less than Mr. Falkenberg proposes.

Q. Can you explain why Mr. Falkenberg's modeling causes the plants to run at such an unrealistically high capacity factor?

A. Yes. Apparently Mr. Falkenberg's approach does not reflect the absence of any market for Gadsby generation during off-peak hours. Unless the model inputs controlling Gadsby's generation are constrained, the model will "run" Gadsby too much.

Q. On page 41 of Mr. Falkenberg's testimony, he states that you have removed Gadsby units 1 and 2 from the dispatch for all but three summer months and infers that this results in an improper level of generation for the Gadsby units in total. Do you agree?

A. No. The Company's modeling of Gadsby resulted in an overall generation level that is conservative when compared to recent history. For example, under the Company's modeling approach, the Gadsby units ran at an overall capacity factor of 49% compared to the 48% capacity factor the units actually ran during a recent high market price period. In regards to Mr. Falkenberg's claim about the availability of Gadsby units 1 and 2, the inputs to the Company's model do *not* show that the units have been removed from dispatch for all but three summer months. I cannot determine the basis for his statement, but it is incorrect.

Q. Should the Company's modeling of Gasdby be adjusted for spinning reserves?

A. Yes. I will address that issue in the context of my rebuttal of Mr. Falkenberg's spinning reserve proposal.

Q. What is your recommendation for Mr. Faleknberg's proposed Gadsby modeling changes as they relate to the overall MWh generation of the units?

A. The Company's proposed modeling of Gadsby produces results that are conservatively representative of the actual operation of Gadsby, unlike Mr. Falkenberg's proposed modeling. Therefore, the Commission should reject Mr. Falkenberg's proposed Gadsby capacity adjustment.

Q. Mr. Falkenberg states that the Company does not lose generation as a result of spinning reserve requirements. Do you agree?

A. No.

Q. Please explain spinning reserves.

A. The North American Electric Reliability Council (NERC) requires all companies with generation to carry operating reserves of 5 percent for operating hydro resources and 7 percent for operating thermal resources. One-half of these reserves must be spinning. Spinning reserves are the amount of capacity that can be ramped up in a 10-minute period. NERC and WSCC require companies with generation to carry spinning reserves to protect the WSCC system from cascading loss of generation or transmission lines, uncontrolled separation and interruption of customer service.

Q. On page 38 of Mr. Falkenberg's testimony, he states that spinning reserves are usually accounted for by dispatching more generating units at any point in time than is required to serve load and not by reducing the capacity of individual units. Do you agree with his conclusion?

A. Yes, I agree that the actual capacity of a unit does not change due to spinning reserve requirements. However, Mr. Falkenberg fails to explain why more generating units need to be dispatched than required.

Q. Please explain.

A. Let's assume that a unit has a capacity of 100 MW and the load at a particular point in time is 100 MW. Without a spinning reserve requirement, that one generating unit would be enough to cover the load. However, with a spinning reserve requirement on the unit of 3.5 percent, (i.e., the unit is required to withhold 3.5 MW for emergencies), the energy output from the unit can only be 96.5 MW. To cover the rest of the 3.5 MW load, additional energy needs to be either generated or purchased. When the 100 MW unit is the most expensive unit of the total system and there is no other unit available, the additional energy has to be purchased from the market. This demonstrates that the capacity rating of the unit does not change due to spinning reserve requirements, but the effect on its output is comparable to a derating of available capacity.

Q. Mr. Falkenberg claims that more generating units than necessary are dispatched to account for spinning reserves. Is this point applicable to this case?

A. No. Given the huge disparity between the high market prices and the low fuel cost of the Company's units, the Company's thermal plants run almost all the time, with a few exceptions (such as Gadsby during off-peak hours). Mr. Falkenberg's colleague in this case, Mr. Hayet, recognized this. On page 23 of his testimony he stated:

> "In PacifiCorp's normalized net power cost case, the annual average cost for its plants ranges from $5.21/MWH for the Dave Johnston plant to about $42/MWH, for the Gadsby plant, while the cost of purchasing from the wholesale market is over $100/MWH. This is quite a disparity, and effectively results in the PacifiCorp units operating at the maximum capacity all of the time".

Therefore, additional generation units are not available to be brought on-line to handle spinning reserves, as Mr. Falkenberg suggests.

Q. On page 38 of Mr. Falkenberg's testimony, he states that hydro resources sufficiently satisfied the Company's spinning reserve requirements in its Western system. Is that a true statement?

A. The statement is generally true, although there are times when west-side spinning reserves are carried on thermal units. This provides a significant level of benefits to the Company's customers because it lowers the Company's overall net power costs.

Q. Is the Company able to carry some of its east-side spinning reserve requirements on the West-side hydro resources?

A. Yes. Through a transmission contract with Idaho Power, the Company is also able to cover a portion of its east-side spinning reserve requirements from western hydro resources, when available and within transmission constraints. For this reason, the Company does not have to carry the full amount of NERC-required spinning reserves on its East- side thermal units and net power costs are lower than they would otherwise be. Nonetheless, the Company must still carry spinning reserves on its east-side resources because it does not have similar hydro capabilities on the east-side of its system.

Q. Do you have any response to Mr. Falkenberg's discussion of the spinning reserve issue from prior Company cases?

A. Yes. Spinning reserves has been a difficult issue for the Company in prior cases because it did not record spinning reserve information on a real time basis. Previously, the Company was required to perform after the fact analysis with data that required assumptions on the Company's part. As a result, the Company was more willing to agree to positions proposed by Mr. Falkenberg, at that time. However, that is not the case anymore.

Q. Please explain.

A. The Company developed a program that records the Company's actual assigned spinning reserves on a real time basis.

Q. What conclusions do you draw from such records, and how does actual spinning reserve compare with what is assumed in the Company's filed net power costs?

A. For the 12-month period from February 2000 to January 2001, shown on Rebuttal Exhibit UPL__.13R (MTW-13R), the average actual spinning reserve for the Company's Eastern system was 70 MW. In this case, the Company used an average of 72 MW for spinning reserves. Further, the amount of reserves assumed in the Company's model is conservative because an adjustment was not made to withhold capacity from other units, when a unit that is assigned to carry spinning reserve is on maintenance.

Q. Has Mr. Falkenberg also changed his positions on spinning reserves?

A. Yes, Mr. Falkenberg has changed his opinion on spinning reserves several times recently. During the 1998 Oregon rate case (UE 111) and 1998 Utah rate case (Docket No. 99-035-10), he modeled east-side spinning reserves at 30 MW on the Company's Cholla facilities. During the recently completed Oregon UE 116 case, however, Mr. Falkenberg originally stated that the Company loses very little generation due to spinning reserves and proposed to model only 6 MW of spinning reserves for the Company's east side resources. Then during the surrebuttal phase of the Company's Oregon UE-116 rate case, he once again revised his proposed spinning reserves, this time from 6 MW to 45 MW for east side resources. Of course, his current proposed modeling still understates the Company's east side spinning reserve requirements.

Q. Mr. Falkenberg claims that the 30 MW of capacity derating on Cholla is not justified based on his examination of the Company's most recent generator logs. Do you agree?

A. No. The spinning reserves utilized in the normalized net power cost calculations are based on the assumption that they are normally carried on the most expensive units on the Company's system. Actual spinning reserves are carried on different units because of system constraints, forced outages, maintenance and market opportunities. Mr. Falkenberg correctly points out that Cholla did not actually carry 30 MW of spinning reserve. However, he chooses not to acknowledge the fact that a portion of the spinning reserve requirements were put on other less expensive units (such as Carbon and Naughton 1 and Naughton 2) which are modeled to carry very little if any spinning reserves.

Q. Mr. Falkenberg asserts that the Company has overstated by as much as 75% the impact of spinning reserve requirements on the availability of generation from the thermal resources. Has he explained the basis of his assertion?

A. No, Mr. Falkenberg's direct testimony does not contain any support for this claim.

Q. Earlier you mentioned that the annual modeled level of spinning reserves is consistent with the actual level of assigned spinning reserves. Is the actual test period level really the appropriate level to model?

A. No. The actual test period level is not consistent with the amount of spinning reserves that the Company carries during high market price periods. This reason is more thermal units are dispatched and the portion of the reserve covered by the west-side resources may no longer be there during periods of high market prices. As shown on Rebuttal Exhibit UPL__.13R (MTW-13R), there was a profound increase in the level of spinning reserves carried on the Company's east side resources when market prices increased so dramatically in June 2000. As a result, the increase in the level of spinning reserves carried by the Company during periods of high market prices should be annualized to reflect this in period cost increase. In addition, I agree with Mr. Falkenberg that the Gadsby modeling should be adjusted to reflect more reserves being carried on the Gadsby units as a result of higher market prices. However, this change does not increase the overall generation levels of the Company's units, which remain consistent with the actual operation of Gadsby during a period of high market prices, whereas Mr. Falkenberg's modeling does not. I also adjusted spinning reserves, to put spinning on other units when units assigned to carry spinning reserves are on maintenance. This revision lowers the Company's net power costs by approximately $3.5 million on a Total Company basis.

Q. What is your recommendation for the net power cost modeling of required spinning reserves?

A. I recommend that Mr. Falkenberg's adjustment regarding spinning reserve should be rejected. The Company's revised level of spinning reserves is reasonable because it is representative of the Company actual operations and is consistent with the general rule of using higher cost units for reserves.

SMUD - Falkenberg

Q. Please explain Mr. Falkenberg's proposed SMUD adjustment.

Q. As a result of the cancellation of a non-regulated nuclear project, the Company entered into a series of complex transactions that resulted in the Company acquiring the firm rights to power from BPA in the future. Subsequently, the Company sold the non-regulated firm energy rights to SMUD for a $94 million payment and later accepted the firm rights to power back as a concession for a sale to SMUD at a rate that was below the then current rate for power. Mr. Falkenberg proposes to adjust the SMUD contract price to the test period price of the SCE wholesale sales contract and believes this treatment is consistent with the treatment adopted in Docket No. 99-035-10. This adjustment reduces the Company's net power costs by $11.5 million on a Total Company basis.

Q. Does the order from Docket No. 99-035-10 suggest that the Commission's intent was to impute SMUD revenues based on the SCE contract during each test year?

A. No. If that were the case, the price utilized in the revenue imputation from Docket No. 99-035-10 would have been $49.42 per MWh, the actual SCE price in 1999. However, the price adopted by the Commission for revenue imputation was $37.00 per MWh. The $37 per MWh represented the expected SCE sale price for the first year the renegotiated SCE contract was in effect. The adopted results therefore do not suggest that the Commission intended to have the price imputation change yearly based on the actual SCE contract price for each successive test year, as proposed by Mr. Falkenberg.

Q. Does the Company believe the renegotiated SCE contract is contemporaneous with the SMUD sales contract?

A. No. The Company does not believe the renegotiated SCE contract is contemporaneous with the SMUD contract. As DPU witness Mr. Burrup testified in Docket No. 99-035-10:

> "the Southern California Edison contract was renegotiated and is not contemporaneous with 1985, which is the SMUD rate".

The Company agrees with this point of view.

Q. Please explain.

A. The pricing changes made in the renegotiated contract were the result of changes that took place in the market about eight years after the original SCE contract was negotiated. From SCE's perspective, it wanted revised pricing terms that would provide what it thought would be more price stability than the original contract. Fortunately for customers, prices have increased quite a bit as a result of the pricing terms agreed to in late 1995. Therefore, the current terms and price of the SCE contract are not comparable to the SMUD contract and should not be used for the purpose of imputing revenues for the SMUD contract.

Q. Would the use of the test period SCE contract price for revenue imputation fit the Commission's reasoning for using a contemporaneous contract?

A. No. In the Commission's Order in Docket No. 99-035-10 the following statement was made:

> "As we have said elsewhere, such a judgement should be made in light of circumstances existing at the time. This view continues to be appropriate and we will apply it in this Docket".

The renegotiated SCE contract cannot be considered to be contemporaneous with the SMUD contract given that the pricing terms were revised to be representative with conditions at the time the contract was renegotiated in 1995, or some eight years later.

Q. Is other information available that demonstrates the renegotiated SCE contract is not contemporaneous with the SMUD contract?

A. Yes. Based on the terms of the renegotiated SCE contract, the price is expected to be almost $80 per MWh in 2001 because the energy price component is escalated based on the annual change in the Southern California border price of gas. The annual effect of this adjustment would be approximately $22 million or 25% of the $94 million payment received by the Company, with 13 years remaining on the contract. Clearly, the method proposed by Mr. Falkenberg would over compensate customers. In addition, it should be noted that the Company did not have any wholesale sales contracts that were indexed to gas prices prior to 1995.

Q. Has the Company had an opportunity to renegotiate the terms of the SMUD contract?

A. No. Unlike the circumstances associated with the SCE renegotiation, SMUD has not been interested in renegotiating its contract.

Q. Is the amount of the revenue imputation adjustment using $37 per MWh consistent with treatment being utilized in other states?

A. Yes. The stipulated adjustment between the Company and OPUC Staff in UE 116 is $2.75 million on an Oregon allocated basis. Using $37 per MWh to impute revenue results in a $2.9 million adjustment on a Utah allocated basis. This is the adjustment the Company has made in its original filing. In contrast, Mr.

Falkenberg's proposed adjustment is significantly higher ($4.3 million on a Utah allocated basis, or $1.4 million higher than the Company's own adjustment).

Q. What is your recommendation for the regulatory treatment of the SMUD contract?

A. The renegotiated SCE contract is not contemporaneous with the SMUD contract, and should not be used as the basis for an adjustment. The continued use of the $37 per MWh imputation price adopted in Docket No. 99-035-10 continues to provide a reasonable outcome. Further, while the stipulation between the Company and OPUC Staff in UE 116 does not establish a precedent, it does provide a reasonable benchmark that demonstrates the excessive size of Mr. Falkenberg's proposed adjustment. For these reasons, the Commission should reject Mr. Falkenberg's proposed adjustment.

Extraordinary Outages (Cholla 4) - Falkenberg

Q. Please explain Mr. Falkenberg's proposed adjustment for 1996 Cholla 4 outage.

A. Mr. Falkenberg proposes to remove a 1996 outage at the Company's Cholla 4 generating plant as a consequence of the Commission allowing the Company to defer replacement power costs associated with the Company's Hunter 1 failure.

Q. Do you agree with his proposed adjustment?

A. No. I disagree for two primary reasons. First, the Commissions approval of the Company's deferred accounting application for the November 2000 Hunter 1 failure has nothing to do with the 1996 Cholla 4 overhaul outage. Further, the Company has not received approval to recover the deferred replacement power costs at this time. Second, the Company did not file to recover replacement power costs associated with the Cholla 4 overhaul outage. Of course, had the Company recovered replacement power costs for the overhaul outage, it would have been appropriate to exclude it from the Company's normalized thermal availability calculation. However, that is not the case.

Q. Was the Cholla outage similar to the Hunter 1 outage as Mr. Falkenberg has suggested?

A. No the Hunter 1 outage was a catastrophic failure of a generating unit during a peak season, while the Cholla outage was a planned major overhaul outage. Therefore, Mr. Falkenberg's suggestion that the two events are similar is false and the Commission should reject his proposed adjustment.

Transmission Modeling Issue - Hayet

Q. On page 4 of Mr. Hayet's testimony, he states that "PacifiCorp has not completed its evaluation of alternative ways to normalize net power costs as required by the Commission, and therefore, for this rate case it had to derive net power costs using a reformatted production dispatch model. As a result, PacifiCorp built an Excel based spreadsheet model to calculate net power costs". Is this a correct characterization of the Company's responsibility in this case?

A. No. The responsibility of evaluating alternative ways to normalize net power costs as required by the Commission was not placed in the Company's hands. The responsibility was placed in the control of the Division of Public Utilities (DPU). In its May 24, 2000 order in the PacifiCorp 1999 General Rate Case, the Utah Public Service Commission stated on page 45

> "We desire the Division and interested parties to undertake an evaluation of alternative approaches to the normalization of net power costs".

The Division, not the Company, was placed in control of the review. A copy of the pertinent page from the order is included as Rebuttal Exhibit UPL__.14R (MTW-14R).

Q. When was the review initiated?

A. After months of delay, the Company telephoned the Division during October 2000 to inquire the status of the review. Subsequently, the Division scheduled the first meeting to discuss the issue on December 8, 2000, some six months after the order was issued. By this time, market prices had skyrocketed and the Company had experienced tremendous increases in net power costs. With the combination of these cost increases and the Commission order from Docket No. 99-035-10 barring the continued use of the Company's PD/Mac model, the Company was left no alternative but to develop a spreadsheet model so it could file to recover the significant price increases it was experiencing.

Q. With these time constraints, was the Company able to build or acquire a robust net power cost model?

A. No. The process of acquiring or building a new model takes a great deal of time. Given the urgent need to seek rate relief to cover the significant costs the Company was bearing, the Company did not have the time necessary to bring a new model online. The Company therefore developed a spreadsheet model that included some simplifying assumptions, one of which was the way the model dispatched and balanced the system. This issue is directly related to Mr. Hayet's proposed transmission modeling adjustment.

Q. Please explain Mr. Hayet's proposed adjustment for transmission modeling.

A. The Company's net power cost model as filed balances the Company's system on an east-side and west-side basis independently from the other. Mr. Hayet proposes to adjust the model so it will dispatch the system on an integrated basis. The proposed adjustment will reduce the Company's net power costs by $32.5 million on a Total Company basis, assuming the Company's proposed market prices are adopted. If Mr. Falkenberg's proposed short-term firm and non-firm market price adjustment is adopted, Mr. Hayet's proposed adjustment would reduce the Company's proposed net power costs by $1.2 million on a Utah allocated basis.

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

A. Not entirely. I agree that it is appropriate to model the Company's system on an integrated basis. In doing so, it is important to make sure transfer capabilities and market sizes are accurate, otherwise the results will still not be correct, despite the attempt at more robust modeling. Our review of Mr. Hayet's proposed modeling changes and the work being done for a new net power cost model led us to find transmission modeling errors in the Company's previous modeling. These errors were incorporated in Mr. Hayet's modeling. In addition, Mr. Hayet assumed unlimited non-firm market sizes, which are not reflective of the Company's ability to buy and sell power. Therefore, his modeling of the Company's system on an integrated basis is wrong because it is not representative of the Company's system.

Q. Why didn't the Company originally model the system on an integrated basis?

A. The Company made simplifying modeling assumptions when developing the model because of time constraints. Two offsetting simplifying assumptions were made with regard to operating the system on an integrated basis. Basically, the model was not allowed to operate on an integrated basis, which increased net power costs and the model was allowed to buy unlimited amounts of energy from the respective markets, which lowered net power costs. It was the Company's opinion that these simplifying assumptions were offsetting, so we were comfortable using the model as filed.

Q. Have you calculated the Company's correct transfer capabilities between its eastern and western systems?

A. Yes. The correct transfer capabilities from the eastern system to the western system and from the western system to the eastern system are shown on Rebuttal Exhibit UPL__.15R (MTW-15R).

Q. Have you calculated the correct market sizes for non-firm sales and purchases?

A. Yes. A calculation of market sizes that takes into consideration firm transmission rights to wholesale markets, existing transactions and various restrictions is provided as Rebuttal Exhibit UPL__.16R (MTW-16R).

Q. Have you calculated the impact of modeling the Company's system on an integrated basis with the correct transfer capabilities and market sizes?

A. Yes. The corrections reduce Mr. Hayet's proposed adjustment to $.8 million on a Total Company basis.

Q. What is your recommendation for this issue?

A. The Commission should accept the adjustment with the Company proposed corrections because it is reflective of the Company's system capabilities.

Q. On page 22, Mr. Hayet states that the Commission may want to investigate the reasons availability has declined so dramatically. Is the premise of this statement correct?

A. No. As I demonstrated above in my rebuttal of Mr. Falkenberg's proposed thermal availability adjustment, the Company's thermal availability has varied within a reasonable range from prior years. Therefore, the Commission should ignore Mr. Hayet's suggestion.

Q. How do you respond to the other modeling changes proposed by Mr. Hayet, including dynamic treatment of forced outages, generation levels between minimum and maximum, ability to model heat rates and time period modeling?

A. While the proposed modeling changes may or may not be appropriate for future use, now is not the right time to address them. The case includes several very large proposed net power cost adjustments, which deserve the Commission's full attention. Since the Company is in the process of developing a new robust net power cost model, Mr. Hayet's recommendations for future modeling changes should be addressed in the context of the new model.

Net Power Costs – Ms. Wilson

Q. Does Ms. Wilson adopt the net power cost adjustments proposed by Messrs. Falkenberg and Hayet?

A. Ms. Wilson adopted all of Mr. Falkenberg's and Mr. Hayet's proposed adjustments except Mr. Falkenberg's proposed adjustment for assumed short-term firm losses. Accordingly, my rebuttal of Mr. Falkenberg's proposed adjustments also address Ms. Wilson's proposed net power cost adjustments. Further, as I mentioned above, Mr. Watters is addressing prudence adjustments, including Ms. Wilson's proposed increase in long-term firm revenue. However, I will address a misperception in Ms. Wilson's testimony in regards to the net power costs adopted in the Company's last case.

Q. Are you referring to page 2 of Ms. Wilson's testimony, where she states that the DPU proposed net power costs of $537 million are $154 million higher than the approximate $383 million from the last rate case?

A. Yes. The Commission adopted Total Company net power costs from the Docket No. 99-035-10 that were approximately $426 million, not $383 million. Therefore, the DPU proposed Total Company net power costs are $111 million higher than the last case, not $154 million.

Thermal Availability, Thermal Maintenance - Herz

Q. Please explain Mr. Herz's proposed thermal availability and thermal maintenance adjustments.

A. Mr. Herz proposes, as Mr. Falkenberg did, that the average thermal availability and maintenance used in the Company's net power cost model should be adjusted to a six-year average from a four-year average. In addition, Mr. Herz proposes to move some thermal maintenance from June to either February or April. The proposed adjustments would reduce the Company's net power costs by $58 million for thermal availability and $58.1 million for thermal maintenance on a Total Company basis. His combined proposed adjustment is much larger than Mr. Falkenberg's because he did not propose to make an adjustment to the Company's short-term firm and non-firm annualized market prices.

Q. Do you agree with his proposal to move to a six-year average?

A. No. His proposed adjustments are essentially the same as Mr. Falkenberg's proposed thermal availability adjustment, except they are made separately. Therefore, the Commission should reject Mr. Herz's proposed adjustments for the same reasons I discussed in my rebuttal of Mr. Falkenberg's thermal availability adjustment.

Q. Are Mr. Herz's proposed adjustments for Gadsby similar to Mr. Falkenberg's proposed Gadsby adjustment?

A. Yes. Mr. Herz also proposes to make adjustments to the inputs for Gadsby so the units run much higher than their recent actual operation during a period of very high market prices. Therefore, my rebuttal of Mr. Falkenberg's proposed Gadsby adjustments are also applicable to Mr. Herz's proposed adjustment.

Q. Does Mr. Herz's alternative recommendation to use the six-year historical availability factors for each unit, combined with the elimination of the high year and low year operating equivalent availability factors, still result in a double counting as you discussed in rebuttal of Mr. Falkenberg's proposed thermal availability adjustment?

A. Yes. The alternative recommendation also double counts prior thermal operation levels.

Q. Does the Company agree with Mr. Herz's proposal to move some of the thermal maintenance from June to either February or April?

A. No. Mr. Herz's proposal to move some of the Company's thermal maintenance from June to either April or February is designed to capture the lower prices for those months. While the Company agrees that it is important to attempt to schedule outages during lower priced periods, that is not the only factor that should be considered. Other factors that also need to be considered are the availability of Company and contract workforces to perform the maintenance, contractual issues, and weather. In addition, it is necessary to plan major outages in advance, at which time the expected market conditions may be different from actuals. An example of this is the spring of 2000, which had higher prices than the preceding winter. The Company believes its modeling of thermal maintenance is appropriate and Mr. Herz's proposal to shift some maintenance should be rejected by the Commission.

Deseret Pricing - Yankel

Q. Please explain Mr. Yankel's proposed adjustment for Deseret pricing.

A. Mr. Yankel states that the Deseret contract should be priced at market and proposes to adjust the monthly price of the sale to the average monthly price of short-term purchases in the Utah portion of the system. The proposed adjustment would reduce the Company's net power costs by $37.3 million on a Total Company basis, utilizing the Company's proposed STF and non-firm market prices.

Q. Do you agree with the proposed adjustment?

A. Not entirely. I do agree that the Deseret pricing included in the Company's filing was too low. However, Mr. Yankel's proposed correction is wrong. Mr. Yankel's correction assumes that the price of Deseret will be the same as the average monthly purchase price for short-term firm transactions. That assumption would be correct only if the short-term firm transactions had the same percentage of on and off-peak MWh. That is not the case. In addition, a portion of the sales is for displacement of Deseret generation. Under the Company's market price proposal there would not be any displacement sales because market prices are well above the displacement price of $7.50 per MWh. The proper method of correcting the Deseret supplemental sale contract would be to eliminate the displacement sales and to price the supplemental on-peak and off-peak energy at the relevant on and off-peak prices.

Q. Have you calculated the impact of the corrected Deseret pricing?

A. Yes. A summary of the revised Deseret pricing is included as Rebuttal Exhibit UPL__.17R (MTW-17R). This would reduce the Company's filed net power costs by $25.3 million on a Total Company basis. If the Commission adopts Mr. Falkenberg's proposed market price adjustments, the $25.3 million increase in net power costs would need to be reversed to be consistent with Mr. Falkenberg's proposal.

WAPA I and WAPA II Wholesale Sales - Yankel

Q. Please explain Mr. Yankel's proposed adjustment for the WAPA 1 and WAPA II contracts.

A. Mr. Yankel proposes to remove the Company's WAPA I and WAPA II contracts from the Company's case. He attempts to justify this adjustment because, in his opinion, the Company normalized short-term firm and non-firm market prices on "going forward prices" and because the contracts had provisions so they could be terminated and eventually did terminate the WAPA II contract and Block A from the WAPA I contract. The proposed adjustment would reduce the Company's net power costs by $41 million on a Total Company basis. If Mr. Falkenberg's proposal to use actual market prices is adopted by the Commission, the adjustment would reduce net power costs by $10.7 million on a Total Company basis.

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

A. No. Mr. Yankel's proposed adjustment is without merit. First, As I explained earlier in my rebuttal of Messrs. Chalfant and Falkenberg, the Company did not normalize short-term firm and non-firm market prices on a proforma (going forward) basis as Mr. Yankel states. The Company adhered to the test period and annualized only the impact of price increases that occurred during the actual test period. Second, the fact that the WAPA I and WAPA II contracts had termination clauses in them is meaningless. The fact remains that both contracts were in effect during the entire test year and should be included in rates.

Q. On page 32 of Mr. Yankel's testimony, he states that these contracts were served from short-term firm purchases. Is that really the case?

A. No. Mr. Yankel's statement is not true. Mr. Yankel can not even make the case that the WAPA contracts are served primarily by short-term firm sales even if he assigned all of the lowest cost resources to retail load and the next lowest costs resources to the highest priced long-term firm wholesale sales contracts.

Q. What is your recommendation?

A. Mr. Yankel's statements in support of his proposed adjustment are fundamentally wrong and his proposal is contrary to the test year rule, which the Commission has used in recent rate cases. Therefore, the Commission should reject his proposed adjustment.

Q. Does this conclude your rebuttal testimony?

A. Yes.