PACIFIC POWER
A DIVISION OF PACIFICORP

July 20, 2006

VIA ELECTRONIC FILING

Oregon Public Utility Commission
550 Capitol Street NE, Ste 215
Salem, OR 97301-2551

Attn: Vikie Bailey-Goggins, Administrator
Regulatory and Technical Support

Re: PacifiCorp's Power Cost Rebuttal Testimony in Docket No. UE-179

Enclosed for filing is an original and 5 copies of PacifiCorp's Power Cost Rebuttal Testimony and Exhibits in Docket UE-179. Copies of this filing have also been served on the UE-179 Service List.

It is respectfully requested that all formal correspondence and Staff requests regarding this matter be addressed to:

By E-mail (preferred):	datarequest@pacificorp.com.
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Informal inquiries may be directed to Laura Beane, Manager, Regulation at (503) 813-5542.

Very truly yours,

Andrea L. Kelly
Andrea L. Kelly LB
Vice President, Regulation

Enclosures

I hereby certify that on this 20th day of July, 2006, I caused to be served, via E-Mail, a true and correct copy of PacifiCorp's Rebuttal Testimony and Exhibits in Docket No. UE-179.

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Peggy Ryan

Peggy Ryan
Supervisor Regulatory Administration

BEFORE THE PUBLIC UTILITY COMMISSION
OF THE STATE OF OREGON

PACIFICORP

General Rate Case

Rebuttal Testimony and Exhibits

Docket No. UE-179

July 2006

Case UE-179
Exhibit PPL/506
Witness: Mark T. Widmer

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Rebuttal Testimony of Mark T. Widmer

NET POWER COSTS

July 2006

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

A. Yes.

Introduction

Q. What is the purpose of your testimony?

A. I will address:

- Mr. Wordley's proposed wholesale margin, ancillary services and extrinsic value adjustments,
- Mr. Falkenberg's proposed adjustments on extrinsic value, short-term firm prudence as it relates to the GRID modeling of short-term firm transactions, Cholla 4 minimum, Sacramento Municipal Utility District (SMUD), the Nucor contract, Desert Power contract, reserve modeling, Cool Keeper, Hydro Modeling (VISTA), Station Service, Reverse Ramping, Reverse DJ-3 Derate, Monthly Outage, Planned Outage Schedule, GP Camas and Foote Creek Wind, and
- Mr. Jenks' testimony on the company's supplemental testimony on contingency reserves and regulating margin, Centralia Formula Power Transmission, extrinsic value, imprudent short-term firm sales and SMUD.

While some of the proposed adjustments are reasonable, I will demonstrate that the majority of the proposed adjustments are not reasonable and should be rejected.

In addition to my rebuttal of the proposed net power cost adjustments discussed above, additional company witnesses will address other specific proposed net power cost adjustments. Mr. Apperson, Director of Trading in the company's Commercial and Trading Department will address the prudence aspect of Mr. Falkenberg's adjustment on short-term firm sales and Mr. Mansfield Vice President of Safety, Environmental and Operations support, will address Mr. Falkenberg's proposed adjustment on imprudent outages.

Stochastic Modeling

Q. Mr. Wordley states that the major inputs to GRID are normalized/smoothed and deterministic. Is this consistent with the normalized ratemaking?

A. Yes. Notwithstanding the wholesale margin and extrinsic value adjustments previously proposed by Mr. Wordley, the use of normalized/smoothed inputs has been the standard for normalized ratemaking for many years in all of the company's jurisdictions.

Q. Would the use of data that is not smooth, somewhat random, and uncertain and correlated to some extent produce a more representative estimate of power costs for setting retail rates?

A. It may, but it is too early to reach the conclusion that stochastic modeling is an appropriate approach for setting retail rates. As part of the UE 170 settlement the company, Staff and other Parties agreed to evaluate stochastic modeling for setting retail rates. The company has held several workshops on this topic, but the process has not been completed. At the last workshop held on June 15, 2006 Staff indicated that they believed the process was long-term in nature and did not expect to reach final conclusions for sometime. So, it is too early to determine whether stochastic modeling should be used to set retail rates or to adopt substitute adjustments predicated on stochastic modeling.

Q. Is it appropriate to partially adopt stochastic modeling?

A. No. As explained by Mr. Wordley, the primary variables that impact net power costs include retail system loads, market prices for natural gas and electricity, thermal power plant forced outages and hydro generation availability. One of the major tenets of ratemaking is to provide a proper matching of costs and benefits. A partial adoption of stochastic modeling for a portion of the major factors that impact net power costs does not provide a proper matching of costs and benefits.

Q. Does the company believe a complete and balanced use of stochastic modeling for all of the major variables that impact net power costs would decrease net power costs?

A. No. Complete and balanced stochastic modeling should increase net power costs significantly on an annual basis because net power cost volatility and normalized net power cost ratemaking are asymmetrically biased in favor of customers. This is demonstrated based on a comparison of actual net power costs to normalized net power costs over for the period 2002-2005, as shown in Exhibit PPL/507. During that period actual net power costs exceeded normalized net power costs by approximately $323 million total company.

Q. If the wholesale margin and extrinsic value adjustments proposed by Mr. Wordley, which are substitutes for stochastic modeling had been adopted from 2002-2005, would the company's level of recovery been even worse?

A. Yes. The company's under recovery would have been significantly worse. On a total company basis the adjustments would reduce net power costs by approximately $65.1 million per year. Over the four year period, the cumulative under recovery would have increased an additional $260 million total company. Mr. Wordley's theory that the company would benefit at the expense of customers without the wholesale margin and extrinsic value adjustments is based on a false assumption. Also, as I explain later in my testimony there are other reasons the proposed wholesale margin and extrinsic value adjustments should be rejected.

Q. What is the company's recommendation for the use of stochastic modeling and the proposed extrinsic value and wholesale margin adjustments?

A. Stochastic modeling or adjustments such as extrinsic value and wholesale margin that are substitutes for stochastic modeling should not be adopted unless a complete and balanced approach for modeling all major factors affecting net power cost variability is used to match costs and benefits. Further, stochastic modeling should not be considered at this time because the process established in Docket UE 170 has not been completed and a consensus has not been reached.

Wholesale Margin Adjustment

Q. Please explain Mr. Wordley's proposed wholesale margin adjustment.

A. Mr. Wordley proposes to adjust the 2007 wholesale margin and volume between short-term firm and non-firm sales and short-term firm and non-firm purchases included in the company's filing to reflect the actual historical volume and margins for the 12-month historical periods ended March 31, 2004 and June 30, 2003. The adjustment is proposed as a substitute for stochastic modeling. He believes the adjustment is appropriate because the actual volumes and margins that occurred during the referenced periods were different than they were forecast for the same period using the company's GRID production dispatch model in Docket Nos. UE 134 and UE 147. Mr. Wordley proposes to reduce the company's net power costs by $38.55 million total company and $10.27 million on an Oregon basis.

Q. How is wholesale margin defined for this adjustment?

A. Wholesale margin is defined as the average price per MWh of short-term firm and nonfirm sales less the average price per MWh of short-term firm and non-firm purchases.

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

A. No. The adjustment is flawed for several reasons and is contrary to the current normalized regulation of the company.

Q. Mr. Wordley states that GRID does not capture the benefits of the company's system characteristics such as load diversity, transmission capability and resource flexibility. Is that the case?

A. No. Consistent with normalized ratemaking these values are captured on a deterministic basis by GRID. The system dispatch portion of the model is a linear program that optimizes the company's system based upon market prices, load requirements, resource characteristics, transmission availability including monetization of available transmission by buying energy in a lower priced market hub and reselling the energy in higher priced market hub and curtailing generation when lower cost market purchases are available.

Q. Does the proposed margin adjustment make sense based on historical information?

A. Not at all. The adjustment is in part predicated on Mr. Wordley's belief that there is approximately $38.55 million of wholesale margin on average that GRID is not capturing, resulting in an over recovery of net power costs if the margin adjustment is not adopted. The proposed adjustment would exist for each and every year, regardless of what the GRID forecast results showed. This does not make sense given the extreme variability of margins. Further, as I discussed above, the company under collected net power costs by approximately $323 million total company for 2002 through 2005. Adoption of this type of adjustment would have made the level of under recovery substantially worse. These results refute Mr. Wordley's hypothesis that the company is over recovering net power costs due to wholesale margins.

Q. Does the proposed margin adjustment properly capture all associated costs?

A. No. Even if one were to agree that the adjustment is appropriate, the adjustment does not capture the fuel costs or purchase power costs of the company's flexible resources that permit actual margins to be achieved.

Q. Please explain.

A. Resources with flexibility can produce intrinsic and extrinsic benefits. Intrinsic value is the benefit created through the normalized dispatch of resources. Extrinsic value is the benefit created through the flexibility of resources and the underlying volatility of the commodities. For example, on an actual basis if the market price of electricity increases at a higher rate than the price of natural gas, a combustion turbine may become more economic to run at a higher level than was dictated under normal conditions and thereby capture the extrinsic value of its flexibility. The extrinsic value of that flexibility is reflected in additional short-term firm or non-firm wholesale sales made possible by incremental generation or through the avoidance of higher priced short-term firm and non-firm wholesale purchases. Thus the gross "extrinsic" value is captured in the proposed wholesale margin adjustment. What is not captured in the proposed margin adjustment is the additional fuel expense or purchase power expense that was incurred to generate the margin.

Q. Does the company's execution of wholesale transactions at market price always provide a positive margin as Mr. Wordley states?

A. Not at all. Actual margins for the period 2002 through 2005 were substantially negative in all years except 2003. The actual margin for 2002, 2004, and 2005 were a *negative* \$2.42, \$3.03, and \$4.75 per MWH, respectively. Positive margins are not assured due to a variety of factors including the timing of the transactions, movements of market prices and the types of products that were purchased and/or sold. For example, if the company bought a 6x16 HLH product to balance a super-peak position because that is what was available in the market, it would have energy that it did not need that would be resold in the wholesale market at a later time. The wholesale margin of that sales transaction would be dependent upon what market prices were at the time of the sale. If prices went up, the sales transaction would provide a positive margin. If prices went down, the sales transaction would provide a negative margin. So there is no guarantee that there will always be a positive margin on wholesale transactions.

Q. Does the company's obligation to serve load also have a negative impact on margins?

A. Yes. If the company is in a balanced energy position and has a forced outage on a large thermal coal generating plant, the company still must meet load requirements because we don't have the discretion to not serve load. Energy will likely be purchased from the wholesale market to meet loads, regardless of the price. This type of transaction has a negative impact on margins because the purchase power price is generally higher than the fuel cost.

Q. Have changes to the GRID model and the company's system occurred subsequent to the Docket No. UE 134 and UE 147 information, on which Mr. Wordley's adjustment is based?

A. Yes. As recognized by Mr. Wordley there have been several improvements to the GRID model, many of which impact wholesale margins. Those changes are summarized on Exhibit PPL/508. There have also been numerous changes to the company's system, which impact wholesale margins. For example, retail load has increased, the company has added the 525 MW Currant Creek combined cycle combustion turbine, wholesale contracts have expired, new long-term firm purchases have been made and market prices for gas and electricity have changed dramatically. These changes render the results from Mr. Wordley's analysis meaningless because the GRID model and our system are different than they were during the UE 134 and UE 147 test years.

Q. Does the information used in Mr. Wordley's proposed adjustment substantiate that there is a substantial impact of changes to the inputs that affect the company's system and GRID?

A. Yes. The adjustment is based on the average of information from Dockets UE 134 and UE 147. If the adjustment were based only on UE 134 information, the proposed adjustment would be $54.9, million total company. On the other hand, if the adjustment were based only on UE 147 information, the proposed adjustment would be $22.2 million total company. This change between the test periods demonstrates that it is not reasonable to use wholesale margin information from a prior historical period to support a proposed adjustment for a future period. The reason for this is the substantial year-to-year variation of wholesale margins.

Q. Why do the margins vary from year-to-year?

A. The margins vary due to a variety of factors. Those factors include variations in: temperature conditions and retail loads, hydro conditions, market prices for natural gas and electricity, the timing and direction of the changes in market prices, the economy, the timing and level of generation and transmission forced outage rates, etc.

Q. Are these factors controllable by the company?

A. No. These factors are not controllable by the company and occur throughout the Western Electricity Coordinating Council region at varying levels and timing. Due to the variability of these factors and the corresponding variability of wholesale margins from year-to-year, historical information is not a good predictor of a future year and should not be used to predict future margins. Thus, the actual margins for the 12-month periods ended March 30, 2004 and June 30, 2003 used in the proposed adjustment have absolutely no bearing on calendar 2007 margins and the current relationship between actual and GRID calculated margins.

Q. Is Mr. Wordley correct that GRID produces lower volumes of wholesale transactions than occur on an actual basis?

A. Yes, as is the case with any hourly production dispatch model that balances and optimizes a forecast test year on an hourly basis. The GRID model produces a lower volume of transactions because it balances loads and resources on an hourly basis with perfect foresight. On an actual basis, system balancing is a long process that involves numerous updates of load and resource balances due to changes in load forecasts, the availability of thermal units, hydro conditions etc., leading up to the actual time of delivery. As a result, actual balancing generates higher volumes than balancing with perfect foresight. Additionally, products available in the market are not always a good fit to balance resource requirements. For example, the company may only need super-peak energy to balance a position but the product that is available is a heavy-load-hour 6x16 product. This requires the company to later sell the shoulder energy, which can produce positive or negative margins depending on market price movements. As such, these types of transactions do not always produce positive margins as Mr. Wordley suggests. These types of balancing transactions also generate higher actual volumes because block transactions usually require additional transactions to fully balance positions.

Q. Are customers being disadvantaged by the lower volumes in GRID in this case?

A. No. Given that the margins produced from normalized results are substantially negative for the 2007 test period, a volume increase to a level near recent actual experience would significantly increase the company's revenue requirement. For example, if the adjustment were based on calendar year 2004 and 2005 actual wholesale volumes and margins and the UE 179 proposed volumes and margins, , the adjustment would increase revenue requirement approximately $302 million and $152 million total company, respectively.

Q. Is Mr. Falkenberg's assumption that as the company gets closer to real time that margins must improve or the company would not enter additional balancing transactions?

A. No. It is important to remember that loads and resources do not typically balance until delivery, and the company needs to balance its energy position through buying and/or selling energy at different geographic locations across its system. As a result, much of this trading activity is not comparable from a profit and loss perspective because the transactions are not comparable. For example, a super-peak power purchase in the Desert Southwest to meet load requirements in that region is not comparable to a wholesale sale of shoulder energy at mid-Columbia to balance the western energy position because the transactions are unrelated. However, that is not to say that the company does not try to get the best price available when optimizing the system through those balancing transactions.

Q. Please explain why the proposed margin adjustment is contrary to current regulation.

A. Current regulation sets the company's rates based on normalized results, not prior period actual results as Mr. Wordley's proposed adjustment uses. Normalized results are predicated on normal conditions including retail loads, hydro conditions, thermal generation, a point forecast of market prices for natural gas and electricity etc. On the other hand, as explained above, actual results are impacted by the variability of factors that occurred during the historical period.

Q. What is your recommendation to the Commission?

A. The proposed margin adjustment should be rejected because it is not consistent with normalized ratemaking. Prior period historical wholesale margin information, as defined in this case, is not relevant to a future test year and is not a good predictor of future test year results. Historical net power cost information demonstrates the adjustment is not appropriate because it would not provide a proper match between costs and benefits. The calculation is flawed because it does not include all relevant costs. The version of the GRID model used in this filing has been improved and is different than prior versions that developed the data used in Mr. Wordley's analysis. Finally, consistent with the generally accepted treatment across the United States, variances between actual and normalized net power costs should be captured through a Power Cost Adjustment Mechanism not through adjustments to normalized ratemaking.

Ancillary Services

Q. Please explain Mr. Wordley's proposed ancillary services adjustment.

A. Mr. Wordley proposes to reduce ancillary service expense to the level of the ancillary services revenue included in the company's case. The proposed adjustment reduces the company's net power cost by $4.1 million total company.

Q. Do you agree with the proposed adjustment?

A. The company agrees with the adjustment as long as the company's supplemental testimony update on contingency reserves for non-owned generation is adopted by the Commission.

Extrinsic Value

Q. Please explain Mr. Wordley's extrinsic value adjustment.

A. Mr. Wordley proposes to capture the extrinsic value of flexible resources on the company's system. The adjustment includes extrinsic value for the West Valley and Gadsby combustion turbines, the Gadsby steam plant, the Currant Creek combined cycle combustion turbine and the Desert Power and APS Supplemental purchase power agreements. The proposed adjustment would reduce the company's net power costs by $26.5 million total company and $7.07 million on an Oregon basis.

Q. Do you agree with the proposed adjustment?

A. No. There are several reasons the proposed adjustment should be rejected. First, the adjustment is intended as a partial substitute for stochastic modeling, which is not the currently approved methodology for ratemaking in Oregon. However, as part of the stipulation with the Parties for Docket No. UE 170, the company has been holding workshops on stochastic modeling in an effort to determine whether it is appropriate for ratemaking. To date no conclusions have been reached. It is certain that there are other cost drivers that should be modeled in any complete stochastic modeling process and that those factors would likely offset the benefits of extrinsic value as demonstrated by a comparison of net power costs in rates to actual net power costs. Those cost drivers include forced outages, retail loads, hydro conditions and market prices. Further, the selection of only one item for a stochastic adjustment does not produce a proper matching of costs and benefits. Because of this, it is premature to adopt any such adjustments. Second, just as wholesale margins are driven by factors not considered in normalized ratemaking, the same is true for extrinsic value because it is driven by the volatility of the market price of gas and electricity. Therefore, the appropriate mechanism for capturing extrinsic value is through a Power Cost Adjustment Mechanism, not the sort of adjustment proposed by Mr. Wordley. Third, as I will explain below, Mr. Wordley's calculation significantly overstates extrinsic value because it overstates potential capacity and unused capacity.

Q. Is there any overlap between Mr. Wordley's proposed margin and extrinsic value adjustments?

A. Yes. As I explained above the gross extrinsic value is captured through Mr. Wordley's proposed margin adjustment because extrinsic value is included in wholesale margins. Therefore, if the Commission adopts the proposed wholesale margin adjustment, the extrinsic value adjustment would be duplicative to the margin adjustment.

Q. Has Staff previously recognized that extrinsic value is captured in actual results?

A. Yes. In Staff's opening brief for UE 116 they stated:

> In other words, historical data reflects the results of actual hourly operation of the power system, implicitly reflecting all the flexibility and diversity value inherent in the company's system. (page 17 lines 10-12)

Q. Do you agree with Mr. Wordley's theory that there is no overlap between his extrinsic value and margin adjustments because GRID generation volumes during the UE 134 and UE 147 test periods for the flexible resources included in the adjustment were higher than the actual generation volumes?

A. No. The theory is wrong. Just because GRID had a higher generation value for the flexible resources does not mean there is not any overlap or there is not any extrinsic value included in actual results. It just means that due to actual spark spreads and other factors during the actual period, the combustion turbines ("CTs") were run less than they were on a normalized basis in GRID. There is no doubt that whatever actual extrinsic value was generated during actual operation for Dockets UE 134 and UE 147 test periods is included in actual wholesale margins.

Q. Are there any flaws with Mr. Wordley's extrinsic value calculation?

A. Yes. The potential capacity factors do not take into account reserves being carried on the units and the assumed capacity factors in the calculation for the natural gas-fired units and the APS purchase are unrealistically high. Both of these incorrect assumptions result in a significant overstatement of extrinsic value.

Q. Why are operating reserves also an important consideration?

A. When a unit is holding operating reserves, it is not available to capture extrinsic value unless the reserves are shifted to another lower-cost unit, which would likely not be economic. Mr. Wordley's analysis did not make an adjustment in his calculation to remove capacity held for reserves, so the unused capacity and extrinsic value is overstated.

Q. Why are the potential capacity factors too high for the natural gas-fired units?

A. Due to heat rates, market prices for natural gas and electricity, and the flat pricing for natural gas and the hourly shaped prices for electricity during the test year, there is no way the natural gas-fired Gadsby and West Valley combustion turbines and the Gadsby steam units would run anywhere near the capacity factors used in the calculation of the proposed adjustment. For example, the adjustment assumes that the Gadsby CTs could run at an unrealistic 90 percent capacity factor, when they have operated at a 25.7 percent capacity factor for the period 2003 through 2005. The same is true for the APS Supplemental power purchase contract which is assumed to have an unrealistic potential capacity factor of 100 percent, but has only operated at a 12 percent average capacity factor for the same period. While the Currant Creek combustion turbine is more economic it is still very unlikely that it would run at a 90 percent capacity factor.

Q. Does the large variance between actual capacity factors and the assumed potential capacity factors used in Mr. Wordley's analysis demonstrate a significant problem with the extrinsic value adjustment?

A. Yes. Mr. Wordley's proposed adjustment is a high level estimate of what the extrinsic value could be for a year, not what it will be for a particular year. In reality the level of extrinsic value can vary significantly from year to year. In one year there could be little or no extrinsic value, and in a later year there could be quite a bit of extrinsic value. For example, when I update Mr. Wordley's extrinsic value calculation to remove the amount of capacity that is holding reserves from the potential capacity factor in the UE179 GRID study and revise the potential capacity factor to reflect average actual capacity factors from 2003 through 2005, the extrinsic value proposed by Mr. Wordley evaporates. In other words, there just was not much extrinsic value for the period 2003-2005. Yet Mr. Wordley proposes to include a $26.5 million total company extrinsic value adjustment each and every year, even though it has been virtually non-existent over the last three years. This is a clear example of why an extrinsic value adjustment should not be built into base rates. More appropriately this type of variability should be captured through a Power Cost Adjustment Mechanism which is designed to capture variability of net power costs.

Q. What is your recommendation?

A. The extrinsic value adjustment should be rejected because it is an unrealistic, one-sided stochastic adjustment that does not provide a proper match between costs and benefits of all stochastic variables. It is premature to adopt any sort of stochastic adjustment because the evaluation established in Docket UE 170 is not complete and it is not consistent with normalized ratemaking. Further, if Staff's proposed margin adjustment is adopted the gross extrinsic value would be duplicative with the proposed wholesale margin adjustment.

Q. Did Mr. Falkenberg and Mr. Jenks also propose similar extrinsic value adjustments?

A. Yes. Both proposed similar adjustments. While the adjustment proposed by Mr. Falkenberg is less than the adjustment proposed by Mr. Wordley and the adjustment proposed by Mr. Jenks' did not include a recommended value, both adjustments suffer conceptually from the same problems as Mr. Wordley's proposed adjustment and should be rejected for the same reasons. The Commission should recognize that it is inconsistent that the parties oppose implementation of a power cost adjustment mechanism, or support only a mechanism with very large dead bands, if they truly believed there were significant benefits that are not being captured by the GRID model.

Short-Term Firm Prudence

Q. Do you agree with Mr. Falkenberg's assessment that there are some serious problems with the company's GRID short-term transaction modeling because additional test period transactions will be arranged even after the October 9, 2006 Transition Adjustment Mechanism ("TAM") update?

A. Not at all. The GRID balancing and optimizing process estimates additional short-term transactions with a linear program to develop the lowest possible cost. The main difference between GRID and actual operations is that GRID does this on an hourly basis with perfect foresight. As explained above, the actual process is a long-term process that continually evaluates changes in our load and resource balance and enters transactions to balance and rebalance the system. This process leads to a higher actual volume. Under forecasted ratemaking, as is preferred in Oregon, actual information will always be different than the forecast. In the end, the best method to capture the difference between actual and forecast transactions would be through a Power Cost Adjustment Mechanism, like the one proposed by the company that captures all net power cost impacts.

Q. Is Mr. Falkenberg's assertion that GRID overstates balancing transactions (non-firm) because it does not model all future short-term firm transactions a valid problem?

A. No. The balancing transactions are a surrogate for short-term firm transactions that may be executed in the future, so the purported problem does not really exist. GRID balances the system on a forecast hourly basis with perfect foresight as other production dispatch models do.

Q. Is Mr. Falkenberg's claim that the company attempts to make a profit on all short-term transactions both firm and balancing misleading?

A. Yes. Of course the company will only make sales if the incremental cost of power is below the wholesale market price of electricity and the company will purchase power at market prices when it is the most economic alternative for meeting load requirements. However, it is frequently the case that the company does not make a profit on a balancing transaction. The company simply executes the best-available balancing transactions at prevailing market prices as long as they are economic. This approach is entirely consistent with the approach GRID uses to balance the system.

Q. Is Mr. Falkenberg's assertion that the current filing assumes an average short-term firm transaction balance of 10.3 million MWh and that the actual average short-term firm volume balance was 40.6 million MWh correct?

A. No. It appears that Mr. Falkenberg has made some math errors. The average volume of short-term firm transactions in the company's current filing is 11.8 million MWh and the average volume of short-term firm transactions for 2005 was 20.5 million.

Q. Did Mr. Falkenberg propose an adjustment related to all of his purported claims about the "serious problems" with GRID short-term transaction modeling?

A. No. Apparently the problem was not that serious. The only adjustment he proposed was related to the prudence of certain short-term firm sales transactions. He did not propose any adjustments related to volumes. So this portion of his testimony should be disregarded by the Commission. Mr. Apperson addresses the proposed short-term firm prudence adjustment.

Cholla 4 Minimum Capacity

Q. Please explain Mr. Falkenberg's proposed Cholla 4 minimum capacity adjustment.

A. The adjustment reduces the minimum capacity from the 250 MW level to 150 MW. He believes this is appropriate because the sodium depletion problem clears up during outages and the minimum can be reset to the 150 MW level. The adjustment would reduce proposed net power costs by $.47 million total company.

Q. Please explain the constraints on the minimum operating level of Cholla Unit 4.

A. The plants physical minimum operating level is 95 MW. However, due to the sodium depletion problem the minimum loading of the plant can increase to 250 MW in a period of 60 days after an outage. After an outage, the sodium depletion issue clears up. The question we are faced with is what the appropriate minimum loading level to model is.

Q. Do you agree with Mr. Falkenberg's contention that the unit seldom operates at the 250 MW level?

A. Yes, however, while Mr. Falkenberg focuses on how often the unit operates **below** 250 MW, he fails to realize that with the removal of hours due to thermal ramping prior to or after an outage, the unit historically has operated **below** the 250 MW level only 2 percent of the time over the two years ending September 2005. By re-running GRID with the minimum operating level of Cholla 4 at 150 MW, the operating level falls below 250 MW approximately 18 percent of the hours. This is inconsistent with the historical results. Therefore, Mr. Falkenberg's proposed adjustment should be rejected.

SMUD

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

A. The proposed adjustment removes the SMUD contract from the company's proposed net power costs. He believes the adjustment is appropriate because he does not think revenue imputation at $37 per MWh is compensatory and the

Southern California Edison (SCE) wholesale sales contract, upon which the revenue imputation has been based expires prior to the start of the test year. He contends that because there is not another contemporaneous transaction, the contract should just be removed from proposed net power costs. The adjustment would reduce proposed net power costs by $18.53 million total company.

Q. Please explain the SMUD transaction.

A. As a result of the cancellation of a nuclear project that was never in rate base or otherwise supported by customers, 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 these "below the line" BPA firm energy rights to SMUD for a $94 million payment. The company subsequently traded this BPA entitlement for a power sale to SMUD at a rate that was below the then current market price.

Q. Do you agree with the proposed adjustment?

A. No. The adjustment would provide more value to customers than the SMUD contract plus and the $94 million payment Just because the SCE contract is expiring does not mean the SMUD contract should be excluded from proposed net power costs or considered to have also expired. Removal of the contract would be too drastic of a step because it would be the same as adjusting the contract to current market value, which was not the original intention of the contract. Further, the adjustment would not be consistent with the treatment of the contract over the last several rate cases, which imputed revenue at $37 per MWh based on the original SCE contract.

Q. What is your recommendation?

A. Although the SCE contract was renegotiated several years ago and the $37 per MWh imputation rate currently included in rates continued to be based on the original contract not the renegotiated contract, I believe the revenue imputation should continue at $37 per MWh to be consistent with treatment for the last several years. If the commission decides that some escalation of the imputation rate is appropriate, I would recommend that the $37 per MWh rate be escalated at the rate of inflation over the remaining term of the contract consistent with the increase in the Consumer Price Index. Mr. Falkenberg's proposal to remove the contract should be rejected.

Q. Did Mr. Jenks propose a similar adjustment to Mr. Falkenberg's SMUD adjustment?

A. Yes. Mr. Jenks' recommendation should be rejected for the same reasons discussed above.

Nucor

Q. Please explain Mr. Falkenberg's proposed Nucor contract adjustment.

A. The adjustment assumes that the existing Nucor contract for ready reserves (non-spinning reserves) which expires on December 31, 2006 will be renewed. The adjustment would reduce proposed net power costs by $3.53 million total company.

Q. Do you agree with the proposed adjustment?

A. No. Even though the company could renew the contract it is not known and measurable at this time because we do not know whether it will be renewed and if renewed, at what price.

Q. What is your recommendation?

A. The Nucor contract should not be treated any differently than other potential contracts. If new contracts are executed by the September 30, 2006 cutoff they will be included in the TAM update. To treat this contract any differently would not be appropriate.

Desert Power

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

A. The proposed adjustment would remove the Desert Power contract because the contract is now not expected to come on-line until June 1, 2007 at the earliest, and there is some uncertainty regarding its fuel supply. The adjustment would reduce proposed net power costs by $13.7 million total company.

Q. Do you agree with the proposed adjustment?

A. Yes. Even though it appears that a revised term sheet will be signed in the near future, there is still some uncertainty, particularly with regard to the on-line date. Further, if the uncertainty is cleared up and the companies sign a new term sheet prior to September 30, 2006, the contract could be incorporated in the TAM update. This would be consistent with the company's proposed treatment of the Nucor contract.

Reserve Modeling

Q. Please explain Mr. Jenks' and Mr. Falkenberg's proposed adjustments for reserve modeling.

A. The adjustment would remove the regulating margin and contingency reserve adjustments incorporated in the company's filing through my supplemental testimony. They contend this is appropriate because they do not believe the adjustments are permissible under the TAM. Mr. Falkenberg's proposed adjustment would reduce net power costs by $25.8 million total company.

Q. Mr. Jenks and Mr. Falkenberg describe the reserve modeling updates as an invalid TAM update. Do you concur with that description?

A. No. As described on the title page to Exhibit PPL/503, the company filed supplemental testimony to the general rate case. The company filed the supplemental testimony coincident with the TAM update to give the parties extra time to review the updates.

Q. Mr. Jenks and Mr. Falkenberg describe the reserve modeling updates as modeling changes (Jenks, page3, line 3) (Falkenberg, page 21, line 3). Do you concur with that description?

A. No. The GRID model logic remains unchanged. The types of model inputs remain unchanged. My supplemental testimony describes an update to existing input attributes and the inclusion of an additional, yet pre-existing, operating reserve obligation.

Q. Mr. Jenks and Mr. Falkenberg claim they did not have sufficient time to prepare a rebuttal on the supplemental testimony. Do you agree with that assertion?

A. No. Mr. Falkenberg and Mr. Jenks had nearly two months to respond to the supplemental testimony. The fact that Mr. Falkenberg spends six pages (page 19 through page 24) in his direct testimony on the supplemental testimony clearly indicates that he had sufficient time to do an exhaustive review of the supplemental testimony.

Q. Mr. Falkenberg claims GRID's modeling of the company's CT is "highly unrealistic" (page 19 line 5). Do you concur with that assertion?

A. No. Mr. Falkenberg's analysis is flawed and misleading. He contends that West Valley Unit 1, a high-cost resource, should operate at its maximum capability so that lower cost resources, such as Cholla, can hold operating reserves. To support this he contends that West Valley Unit 1 normally operates at its maximum capability. Both assertions are inaccurate.

Q. Please explain.

A. Mr. Falkenberg examined West Valley Unit 1 hourly generation as provided in the company's supplemental response to ICNU Data Request 1.24. Based on this examination, Mr. Falkenberg claims, "the CT unit normally operates at a range of loading up to their maximums". In addition, he asserts, "This unit is typical of PacifiCorp's CTs". From this, the reader is lead to believe that operating at anything other than maximum is undesirable. Mr. Falkenberg's conclusions are incorrect.

Q. What is the proper operating level for a CT?

A. That depends on the size of the operating reserve requirement and where the company holds operating reserves. If the choice is between holding operating reserves on a low-cost coal unit and holding operating reserves on a high cost gas unit, the GRID model chooses the high-cost gas unit. The company ran a GRID scenario where the company directed the model not to hold reserves on the gas

CTs. The result was an increase in net power cost of $14.5 million total company.

Q. Mr. Falkenberg claims that "the CT unit normally operates at a range of loading up to their maximums". This is at odds with your preceding testimony that states his conclusion is incorrect. Who is correct?

A. Over the 25 month's worth of hourly data provided to Mr. Falkenberg, West Valley Unit 1 operated in total 5703 hours or an average of 2737 hours per year. Of those 5703 hours, West Valley Unit 1 operated above 30 MW 37 percent of the time – this level is not normal.

Q. Still, the 37 percent and the 2737 hours are significantly different from the corresponding values of the GRID dispatch. How do you account for the difference?

A. At times, history can be a guide in predicting the future. However, the forecaster needs to temper the use of history in a forecast with an understanding of the dynamics driving the behavior. As noted above, the operating reserve requirement is a major driver in the commitment and dispatch decisions. The East control area's net operating reserve requirement in the two-year historical period has a different set of underlying factors than in the normalized forecast period. These include:

- Drier hydro conditions in the western control area during the two-year historical period left additional discretionary capacity available for holding reserves for the east control area.
- Prior to November 2005, the Grant County Priest Rapids Project contract provided to the company a larger share of the project. This, in turn,

provided additional discretionary capacity for holding reserves for the east control area.

- The addition of the Currant Creek combined cycle combustion turbine in early 2006 changes the mixture of purchased power to owned generation and therefore the two year historical period and the forecast period are different, which in turn changes the operating reserve requirement.
- A higher volume of purchased operating reserves in the two-year historical period lowered the net operating reserve requirement. On page 17, Mr. Falkenberg proposed an adjustment regarding the NUCOR operating reserve contract. However, Mr. Falkenberg did not calculate the impact of his NUCOR adjustment on the dispatch of the gas peaking units.

In addition to the above, GRID is optimizing the dispatch with normalized data and perfect foresight. The operators of the company's system do not have that advantage and cannot be expected to perfectly dispatch.

Q. Regarding the size of operating reserves, Mr. Falkenberg states, "I raised this issue is several other cases, and all were resolved by settlement." (page 21, lines 20-21). The reader is lead to believe that the company adopted his position. It that a correct assessment?

A. No. Prior net power cost settlements were "black box" settlements without comments on the merits of individual issues. The company has never agreed with Mr. Falkenberg's position on this issue.

Q. Mr. Falkenberg states, "... the new PacifiCorp analysis defines regulating margin as the difference between the average 5 minute hourly peak demand and the hourly average demand". Is that a true statement?

A. No. The study defines regulating margin as the difference between the maximum 5-minute load and the 5-minute average hourly load. The study uses this definition to establish an estimate of the actual regulating reserve requirement. In reality, the change in load from one level to another is just one component of system regulation. Another component of system regulation getting increasing attention is the impact of wind resources on the regulation margin. If anything, the company's regulation margin calculation is conservative because it does not include the impact of wind resources.

Q. Mr. Falkenberg makes the point that the regulating reverse requirement is "performance based". From this, he concludes that any measure of the regulating reverse requirement based on the ramp within an hour is invalid. Is this a logical conclusion?

A. No. The fact that NERC does not establish a formula for the regulating reserve requirement does not mean that utilities are unable to develop an estimate of the regulating margin requirement. The company needs to be able to forecast requirements so that it can operate its system appropriately by following load in order to meet its NERC performance criteria.

Q. Mr. Falkenberg describes the company's non-owned generation update as "… due to reflecting contingency reserve requirements for QFs …" (page 22, lines 22-23). He goes on describe this adjustment as a company's attempt to compensate for an alleged oversight in Docket UM 1129 (pages 23, lines 6-8). Do you concur with that assertion?

A. No. The company models all QF purchase contracts as unit contingent, meaning the company must carrying contingency reserves for those contracts because the operator cannot carry reserves for their single plant. The company's non-owned generation update relates to other non-owned generation in the company's control area that does not go to serve the company's retail load. My supplemental testimony did not refer to QF purchase contracts nor did it refer to avoided cost issues. UM 1129 has no relevance to this case.

Cool Keeper

Q. Please explain Mr. Falkenberg's proposed Cool Keeper adjustment.

A. The proposed adjustment would increase the size of the program based on more current information and expand the curtailment period to be consistent with the tariff. The adjustment would reduce proposed net power costs by $.17 million total company.

Q. Do you agree with the proposed adjustment?

A. Yes.

Hydro modeling

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

A. The adjustment would replace the company's hydro generation forecast developed using the company's VISTA hydro generation model, with the mean based on hydro generation derived from historical hydro generation information from the company's prior Washington general rate case. Mr. Falkenberg believes this is appropriate because the company's hydro forecast overstates extreme conditions. The adjustment would reduce proposed net power costs by $2.46 million total company.

Q. Do you agree with Mr. Falkenberg's claim that the current VISTA hydro model results, stated in the form of three exceedence levels overstates the likelihood of extreme hydro events?

A. No. Similar to the real world, the likelihood of extreme hydro events is a function of the underlying character of the assumed hydrologic conditions, and the ability of the model to manage the water to avoid extreme conditions. The input data is comprised of the best empirical information available at the time the forecast is produced. It includes the current state of physical plant, biological, regulatory operating constraints and system characteristics, i.e., whether the plant is a run of river facility or a facility with a storage reservoir and maintenance outage scheduling. This information is combined with the natural phenomenon of varying streamflow levels, to allow the VISTA model to produce a probabilistic forecast of hydro generation. The company agrees with Mr. Falkenberg that hydrology is not likely to be consistent across the wide geographic region covered by PacifiCorp and therefore reduced the range of hydro generation from the full range of hydrology to levels closer to the expected level of generation. That way when the data is brought together the overall effect is a reasonable likely outcome.

The exceedence levels (25^{th}, 50^{th} and 75^{th} percentiles) should be looked at as an envelop that is likely to include the actual levels of generation. As Mr. Falkenberg notes in his testimony, extreme events such as a VISTA forecast of the 5^{th} or 95^{th} percentile are excluded.

Q. What do the 25^{th}, 50^{th}, and 75^{th} percentiles represent?

A. They represent the likelihood that generation will exceed that particular level. The 25^{th} percentile represents a wet period where 75 percent of the time the expected level of generation will be less than that level. The 75^{th} percentile represents a dry period where 75 percent of the time the expected level of generation will be higher than that level. The 50^{th} percentile represents the median generation level where 50 percent of the time the expected level of generation will be greater than the median and 50 percent of the time it will be less than the median.

Q. Why are the 5^{th} and 95^{th} hydro exceedence levels extreme and the 25^{th} and 75^{th} are not?

A. The 25^{th} and 75^{th} percentiles are within one standard deviation of the mean for all the hydro outcomes. By statistical standards this is a very conservative estimate of the total possible variation from the expected level of generation. On the other hand, the 5^{th} and 95^{th} percentiles barely fall within two standard deviations from the mean level of generation. Thus the 5^{th} and 95^{th} percentile generation levels are extreme and the 25^{th} and 75^{th} percentile generation levels are not extreme as Mr. Falkenberg suggests.

Q. Do you agree with Mr. Falkenberg's solution to his 'extreme events' hypothesis?

A. No. Mr. Falkenberg substitutes the as-filed GRID hydro forecast data with an obsolete data set that no longer represents the operational constraints and capabilities of the company's hydro generation facilities. He supports this substitution with the argument that it is more mathematically accurate to use the mean of the substituted data set than the as-filed three exceedence level forecast produced by VISTA.

Q. What is wrong with using the older data?

A. The problem with using older historical generation is that in many cases the plant has changed, i.e. a runner or generator replacement or improved gates and electronics. The other single factor that makes the historical data obsolete is that the rules of plant operation have changed at nearly every plant on our system. New licenses have changed the requirements for bypass flow and minimum releases.

Q. Does Mr. Falkenberg provide any statistical analysis to support this contention?

A. None whatsoever. Mr. Falkenberg simply provides an exhibit showing the calculation of the average annual generation for each of the company's owned hydro facilities.

Q. Has the company performed any statistical analyses to determine the accuracy of Mr. Falkenberg's claims?

A. Yes. The general conclusion is that there is little statistical significance to support the contention that the company's current method of hydro modeling is inaccurate or improved on by using the mean rather than three exceedence levels.

Q. **If there is no statistical support for this adjustment, what criterion did Mr. Falkenberg use to select his methodology?**

A. The only apparent reason is that using the mean and the obsolete hydro information produces higher hydro energy levels and thus a decrease to net power costs. The company uses the three exceedence level methodology to capture normalized power costs over a reasonable range of expected hydro conditions. A single level of hydro generation does not represent a reasonable range.

Q. **When evaluating the performance of VISTA hydro forecasting for use in a rate case, is the company attempting to take advantage of predicted, lower levels of hydro generation?**

A. No. The company uses the VISTA model for regulatory filings, near-term production planning and long term planning because we believe it produces the best forecast.

Q. **Mr. Falkenberg has stated that the hydrologic record does not include "even a single year" of water data that is comparable across all plants. Is that an accurate statement?**

A. No. The company has records of hydro generation that are comparable for its system for the period 1989 through today. After correcting for resources that have been decommissioned, it is a good record of historical hydro generation. The issue is that this historical record does not reflect the operating rules and guidelines that are in effect today. The reason for using VISTA is that with the model, one can quickly determine the possible generation from a new operating regime or new equipment under a wide variety of hydrologic conditions. Thus, we can look ahead without knowing what the streamflow conditions will be and identify the expected hydro generation for the total system with reasonable confidence.

Q. What is your recommendation?

A. The proposed adjustment should be rejected because the data used in the analysis is not representative of the company's hydro system during the test period because it is from a prior rate case. There is no statistical evidence to support forecasting hydro generation based on the mean. The adjustment appears to be an unjustified attempt to lower proposed net power costs. The method employed by the company is the same method used for internal planning.

Station Service

Q. Please explain Mr. Falkenberg's proposed station service adjustment?

A. Mr. Falkenberg proposes to eliminate the company's station service adjustment because he believes: a) the adjustment is not well supported, b) is not industry standard and c) GRID understates coal-fired generation. The proposed adjustment would reduce proposed net power costs by $4.27 million total company.

Q. Do you agree with the proposed adjustment?

A. No. Whether or not another utility models station service during outages in the same manner as the company is irrelevant and not a sound reason for rejecting the company's adjustment. The fact remains that the company's modeling of loads and resources does not capture station service when a unit is off-line.

Q. **How does the company model the load associated with station service when thermal units are off-line?**

A. Station service is modeled as an addition to retail load to capture the associated system cost. The information is captured and provided by PacifiCorp Energy's Compliance Reporting Department.

Q. **Why isn't station service captured in the load and resource modeling?**

A. Load is equal to net generation plus interchange. Net generation only captures station service when the units are running, thereby, excluding station service when the units are not running. To be consistent, heat rates are also calculated based on when the thermal units are running and do not include the impact of station service when the units are not running. Unless a separate load adjustment is made, as proposed by the company the cost of that station service will not be recovered by the company and there will not be a proper match between costs and benefits.

Q. **Has the company provided evidence that demonstrates station service is not captured in load?**

A. Yes. The company's supplemental response to OPUC data request 360 provided an actual hourly load calculation. That information demonstrated that station service shows up as negative generation when an individual thermal unit is offline and is thereby excluded from net generation.

Q. Do you agree with the portrayal in Mr. Falkenberg's Table 2, that GRID generation understates actual coal generation for the 48-month period ended September 30, 2005?

A. No. Just the opposite is true. The information used in Table 2 for actual generation is incorrect because it includes generation for the Hunter 1 and Hunter 2 generation plants owned by our partners. To correct Table 2, the 4-year average actual generation of 45.8 million MWh should be reduced by 1.4 million MWh to remove our partners' Hunter 1 and 2 owned generation. This correction reduces the 4-year average actual generation to 44.4 million MWh, which is substantially below the 45.1 million MWh produced by GRID in the company's original filing and the 44.9 million MWh included in the TAM filing update.

Q. What is your recommendation for this adjustment?

A. The proposed adjustment should be rejected because Mr. Falkenberg's claims are groundless as demonstrated by the company's supplemental response to OPUC data request 360, the Table 2 analysis used to discredit the need for the company's adjustment is incorrect and correction of Table 2 supports the company's modeling.

Reverse Ramping

Q. Please explain the reverse ramping adjustment proposed by Mr. Falkenberg.

A. The proposed adjustment reverses the ramping adjustment included in the company's filing. He believes the company's adjustment is not warranted because he believes GRID understates actual coal-fired generation and the company's modeling approach is not standard industry practice. He also believes the Oregon

Commission Order in Docket UE-139 is supportive of his adjustment. The proposed adjustment would reduce proposed net power costs by $3.68 million total company.

Q. Do you agree with the proposed adjustment?

A. No. The reasons stated by Mr. Falkenberg in support of his proposed adjustment are either incorrect or do not provide a sound basis for the proposed adjustment. For example, as I explained above GRID does not understate coal-fired generation, GRID coal-fired generation exceeds the 4-year average actual generation by over 500,000 MWhs.

Q. Is there any substance to the argument that the company is modeling phantom outages and that the modeling is not standard industry practice?

A. No. The company has merely used an alternate modeling approach to capture the cost of thermal ramping because GRID is not currently structured to capture ramping as some models do.

Q. Please explain.

A. The availability rates in GRID assume that coal fired units are available at full load when being ramped down for maintenance and when restarted and ramped up after planned maintenance and forced outages. In reality, coal-fired units are not available at full load when ramping down for maintenance and when ramping up from outages due to the physical capabilities of the units. Generation is lost while a unit ramps to the minimum level required for synchronizing with the GRID and when a unit is being shut for maintenance. The company's ramping methodology simply reduces thermal availability to reflect generation not available due to ramping to match costs and benefits.

Q. Do you agree with Mr. Falkenberg's suggestion that the UE-139 Commission decision that rejected PGE's ramping adjustment is on point relative to the company's thermal ramping adjustment because it rejected an ad-hoc data manipulation?

A. No. The circumstances are completely different and therefore the PGE order does not provide a sound basis for disallowing the company's adjustment. PGE merely speculated that the problem was related to ramping. In the company's case, there is no speculation. It is a fact that the company's thermal generation is lower as a result of ramping before and after the thermal plants are down for maintenance and after outages. Customers are not being harmed by the company's modeling, they are only being asked to pay for costs related to the benefits they already receive. For these reasons and the others explained above, Mr. Falkenberg's proposed adjustment should be rejected.

Reverse DJ-3 Derate

Q. Please explain Mr. Falkenberg's proposal to reverse the company's rerating of the Dave Johnston Unit 3 generation plant.

A. The proposed adjustment would increase the company's official rerated net generation capability of 220 MW to 230 MW. He believes the adjustment is appropriate because at times the unit runs above the 220 MW level. The adjustment would reduce proposed net power cost by $3.68 million total company.

Q. Mr. Falkenberg claims that the company's de-rate adjustment to Dave Johnston 3 is not reasonable. Do you agree with that assertion?

A. No. The unit is limited by state law to 1.2 lb/MM Btu SO2 as long as the heat input is below 2500 MMBtu per hour. If the unit exceeds the 2500 MMBtu heat input number, a reduction in the SO2 emission rate is triggered to 0.5lb/MM Btu SO2. Through analysis, the company determined that running the unit at the 2500 MMBtu/hr heat input number the unit produces approximately 220 MW of net generation. If the company triggers the 0.5 lb/MMBtu SO2 emission limit the company either has to build a scrubber or find a lower sulfur coal source. There are no plans to build a scrubber by the end of the test period and the company is already burning among the lowest sulfur source coals available.

Q. Mr. Falkenberg states that in the last year, 2005, the level of generation at the Dave Johnston 3 unit has exceeded the 220 MW level approximately 1200 hours. Did the company exceed the state imposed emission limit in these hours?

A. No. The company reviewed the 48 month historical generation levels ending September 2005, consistent with the data used to determine the thermal de-rates included in GRID. The company found that over the last two years of the data, the generation level was above 220 MW on average 700 hours of the year or approximately 9 percent of the time. During these hours, the level of generation was on average 222 MW. This is due to variations in the sulfur content of the coal source. Through the company use of targeting the SO2 emission limit, the level of generation could slightly be above 220 MW a limited amount of time but not consistently.

Q. Given the results of the analysis, do you agree with Mr. Falkenberg's proposed adjustment to the Dave Johnston 3 capacity?

A. No. Mr. Falkenberg proposes to change the capacity at Dave Johnston 3 to 230 MW. In doing so, GRID would calculate the Equivalent Availability of this unit above 220 MW 100 percent of the time. Given the historical data and the company's SO2 emission limit target, this adjustment is unreasonable. The company believes that the 220 MW capacity is the appropriate level at which to run the Dave Johnston 3 unit. For these reasons, Mr. Falkenberg's proposed adjustment should be rejected.

Monthly Outage

Q. Please explain Mr. Falkenberg's proposed monthly outage rate modeling adjustment.

A. The proposed adjustment would reverse the company's monthly modeling of forced outage rates and substitute annual forced outage rates. He believes his adjustment is appropriate because it is not industry practice and outages are random. The adjustment would reduce proposed net power costs by $2.29 million total company.

Q. Do you agree with the proposed adjustment?

A. No. As I previously discussed one of the major principles of ratemaking is to properly match costs and benefits. While I agree that outages are random, there is a lumpiness to those outages each and every year. In some years the lumpiness may be more or less favorable to the company. Because the market value of energy varies from month to month and sometimes significantly, it is important to match the lumpiness of the outages with the cost of the outages in order to ensure the company is recovering its costs and customers are not paying too much. This is not possible with annual outage rate modeling because it is always assumed that the outages occur equally every month of the year and we know that is not the case. On the other hand, the use of the company's monthly 48-month rolling average outage methodology will ensure that costs and benefits are matched.

Q. Is the methodology used in this case a significant departure from the previous methodology?

A. No. The only difference is that we moved from annual outage rates to monthly outage rates. The total level of outages is actually the same. This is consistent with the use of monthly information for other GRID inputs.

Q. Why did the company switch to a monthly 48-month rolling average compared to its prior use of a 48-month rolling annual average?

A. As market prices have escalated to the levels prevalent in the wholesale market today it is very important to match costs and benefits. Failure to do so could exacerbate what has been a significant under recovery of costs for some time for the company. Historically, with lower market prices, monthly modeling was not as important as it is today because the cost of outages was much less. While Mr. Falkenberg states that monthly modeling has not been an industry standard I believe it may only be a matter of time before other utilities recognize this issue. However, it may not be as important to other utilities.

Q. What is your recommendation for the proposed adjustment?

A. The Commission should reject Mr. Falkenberg's proposed annual forced outage rate modeling because it does not provide a proper match between costs and benefits.

Planned Outage Schedule

Q. Mr. Falkenberg proposes an adjustment due to the shape of the normalized planned outage schedule (page 35, lines 6-7). Do you agree with this adjustment?

A. No. Mr. Falkenberg has a valid point regarding the shape of the company's normalized planned outage schedule. However, his adjustment is seriously flawed. The company compared the capacity on maintenance in the normalized planned outage schedule with the capacity on maintenance in the 48-month historical period. The company concluded, the normalized planned outage schedule needs to change as follows:

- The Currant Creek fall planned outage should move to the spring.
- The planned outages in January should move into March and April.

In the revised schedule, the January schedule for Gadsby and West Valley moved forward four weeks and Currant Creek moved from October to May. These changes caused other units to reshuffle to maintain the shape of the capacity on maintenance consistent with the 48-month historical period. Applying the above changes to the planned outages lowers proposed net power costs by $1.3 million total company.

GP Camas

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

A. The proposed adjustment reduces the expected level of generation during the test period based on a 48-month historical trend line. He believes the adjustment is appropriate because he expects the decline in generation to continue at the same rate it previously declined. The adjustment would reduce proposed net power costs by $69,000 total company.

Q. Do you agree with the proposed adjustment?

A. No. Recent history demonstrates that the decline in generation previously experienced has stabilized. So, the trend line analysis used by Mr. Falkenberg to predict generation during the test period understates the expected level of generation.

Q. What level of generation did the company use in the GRID model?

A. Consistent with previous rate cases, the company modeled the level of generation as the most current historical 12-month level. At the time the company prepared the filing, information was available for the 12 months ending September 2005. The company currently has information for the 12 months ending May 2006.

Q. If the company used updated information would the result be essentially the same as it is in proposed net power costs?

A. Yes. Re-running the GRID model with information for the twelve month period ending May 2005 only decreases proposed net power costs by approximately $1,400 total company. This demonstrates that the trend line proposed by Mr. Falkenberg understates expected generation levels and therefore should be rejected.

Foote Creek

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

A. The proposed adjustment increases the generation for the Foote Creek wind generation project. The adjustment reduces proposed net power costs by $.89 million total company.

Q. Do you agree with the proposed adjustment?

A. Yes.

Centralia Formula Transmission (FTP) contract with BPA.

Q. Mr. Jenks claims that because the contracts to replace the expiring Centralia FTP contract are not energy contracts, they are not eligible for inclusion in the next TAM update (page 5, lines 14-21). Do you concur with that assertion?

A. No. The TAM update procedure does not distinguish between new energy contracts and new transmission contracts, it applies to all net power cost components, one of which is wheeling contracts. Mr. Jenks claims that a new transmission contract requires a prudence review. Yet, in the nearly two months that my supplemental testimony was available to Mr. Jenks, Mr. Jenks did not submit a single data request regarding the need for additional transmission capability after the existing FTP contract expires. The company specifically mentions the expiring FTP contract in the supplemental testimony to make parities aware of a potentially large expense issue.

Q. Does this conclude your rebuttal testimony?

A. Yes.

Case UE –179
Exhibit PPL/507
Witness: Mark T. Widmer

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Rebuttal Testimony of Mark T. Widmer

Power Cost Comparison

July 2006

PacifiCorp - Oregon
NPC In Rates Vs Actual
2002-2005

	2002	**2003**	**2004**	**2005**
NPC in Rates	591.7	648.2	598.0	643.6
Actual NPC	677.7	598.2	745.6	782.8
Difference	(86.0)	50.0	(147.6)	(139.2)
Average Difference	(80.7) 2002-2005			

Notes:

2002 NPC in Rates Docket #UE-134 effective August 1, 2002 ($589.0 million)
2003 NPC in Rates Docket #UE-147 effective September 1, 2003 ($598.0 million)
2003 NPC in Rates includes 56 million of Summer 2002 Purchase Power Deferral
2005 NPC in Rates Docket #UE-170 effective October 4, 2005 ($785 million)

Case UE –179
Exhibit PPL/508
Witness: Mark T. Widmer

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Rebuttal Testimony of Mark T. Widmer

GRID Model Changes

July 2006

GRID Release Summary

December 2001: First use of GRID in general rate case
- Oregon Docket UE-134

March 2004: GRID release 2.1&2.2
- Logic enhancements:
  - Apply a credit for backing down thermal units in the operating reserve calculation.
  - Apply a credit for quick start thermal units that are not committed in the operating reserve calculation.
  - In regulating margin calculation, consider the change in net interchange when calculating the change in system load.
  - In regulating margin calculation, determine which direction the system load is changing when calculating the change in system load.
- Logic corrections:
  - Apply the Reserve Credit as a credit not as a debit.
  - Apply startup cost to the generation using the Commitment Operating Level versus the nameplate.
  - Correct error regarding restrictions and non-hourly time period.
  - In the logic for the Energy Limited archetype, the time period was off by one hour.

May 2004: Grid release 2.3
- Logic corrections:
  - Correct issue with multi delivery points that tie to the same reference market.
  - Correct special 15-hour heavy load hour (HLH) definition for the BPA Peaking contract.

May 2005: GRID release 5.1
- Logic enhancements:
  - Create a peak shaving algorithm to dispatch a resource against the net system load.
  - Add planned outage functionality for hydro plants
  - Add ramp rate functionality for hydro plants
  - Change hydro reserves capability to a MW parameter – versus a yes/no attribute.

December 2005: GRID release 5.2&5.3
- Logic enhancements:
  - Dynamically determine the marginal unit for the reserve credit calculation.
  - Limit the reserve credit to when there is a reserve obligation.

Case UE-179
Exhibit PPL/1200
Witness: John A. Apperson

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Rebuttal Testimony of John A. Apperson

SHORT-TERM FIRM SALES

July 2006

Q. Please state your name, business address and present position with PacifiCorp (the company).

A. My name is John A. Apperson, my business address is 825 NE Multnomah, Suite 600, Portland, Oregon 97232, and my present position is Director, Energy Trading.

Qualifications

Q. Briefly describe your educational and professional background.

A. I received a Bachelor of Science degree in electrical engineering from Oregon State University. I have worked for PacifiCorp since 1982 and have held various positions in transmission planning and commercial and trading areas. I was promoted to my current position in April 2000. I am a Registered Professional Engineer in the state of California.

Q. What are your responsibilities as Director of Energy Trading?

A. I am responsible for financial and physical hedging and balancing of the company's energy position in the wholesale market, and associated activities performed by the cash and forward trading, real-time trading, and the prescheduling groups to economically meet the company's load obligations.

Purpose of Testimony

Q. What is the purpose of your testimony?

A. I will respond to Mr. Falkenberg's questions and Mr. Jenks' statements about the prudence of short-term firm sales which the company entered into in 2004 for delivery in 2007.

Prudence of Short-Term Firm Sales

Q. **Did PacifiCorp make a disproportionate number of below-market sales in 2004 for delivery in 2007 at the Mid-Columbia?**

A. No. The sales which the company entered into were not priced below market. Each of the sales was executed at or near the prevailing forward market price on the day of the transaction.

Q. **Should the company's transaction prices for those sales be compared to the company's December 30, 2005 official forward price curve?**

A. No. This is not an appropriate comparison. A "below-market" transaction would be a transaction whose price is below the forward market price on the day of the transaction. For regulatory purposes, prudence is determined by evaluating the information available at the time of a transaction. To describe the company's sales as "below market" by comparing the sale prices to forward market prices transacted on a day other than the day the sales were transacted is inappropriate and misleading.

Q. **How is Mr. Falkenberg's transaction price comparison inaccurate and misleading?**

A. Mr. Falkenberg suggests that the company could have perfect foresight of market prices in the forward market and the prudence measure is one of precise timing without regard to risk to the company or its customers.

Q. **Did PacifiCorp take a short position, as described in Mr. Falkenberg's testimony, thereby exposing the company to market price volatility?**

A. No. While it is true that PacifiCorp made sales in the last quarter of 2004 for delivery in 2007, it is also true that the sales were made to offset a west side long energy position for both heavy load hour and light load hour periods. The company's energy positions were long prior to the sales. The company's 2007 energy positions after the sales were made in 2004 were still long, although less so, as the sales reduced the company's west side long position. These sales reduced the company's overall exposure to market price volatility.

Q. Did the company sell power, as described in Mr. Jenks' testimony, which could have shored up its east side short capacity position?

A. No. The company made sales in 2005 for delivery in the months of 2007 where the company held a long position. The sales reduced the company's exposure to market price volatility.

Q. Did the company make any sales for delivery in the third quarter of 2007, the period the IRP showed a capacity deficit?

A. Yes. The company made two 25 MW sales for delivery in the third quarter of 2007. These sales were made at a time when the company had a long energy position. Therefore, the sales reduced the company's exposure to market price volatility.

Q. Were these transactions consistent with the company's risk management policies?

A. Yes. The company's policy was to balance its energy position up to 48 months in advance of delivery to mitigate the company's exposure to market price volatility. This policy was equally applicable to making sales when the company's energy position was long and making purchases when the energy position was short. The company adhered to a value-at-risk limit and to position limits to limit the company's and customers' exposure to market price volatility.

Q. What is a value-at-risk limit?

A. Value-at-risk is a measurement established by the company's board to limit the company's exposure to financial losses. The company employed a calculation to prudently manage its risk exposure and minimize its cost of capital. The company balanced its energy position to remain within this limit at all times. Utilization of a value-at-risk limit is a customary practice in the energy industry.

Q. What is a position limit?

A. Similar to value-at-risk, a position limit is a measurement established by the company's risk policy for the purpose of limiting the company's energy positions at individual market hubs, as well as its overall energy position to further mitigate its exposure to market price volatility. These limits were applied to monthly and quarterly periods for heavy load hour and light load hour energy positions over a forward period.

Q. Were any of the 2004 sales speculative trading activity?

A. No. The company did not make sales resulting in increased price exposure purely in anticipation of making a profit due to anticipated price movements.

Q. Was the company's west side long position entirely at the Mid-Columbia?

A. No. Sales were made at Mid-Columbia to reduce the company's exposure to market price volatility for the company's overall west system position, including California-Oregon Border and points internal to the company's system.

Q. What is the company's process to balance its 2007 energy positions?

A. The company begins to balance its energy position up to 48 months in advance of delivery. Typically, annual and quarterly products are available and monthly products are not available for forward periods with this time horizon. Therefore, the company transacts to balance its average energy position with annual and quarterly products, even if the energy position is increased for one or more months. These transactions have the effect of decreasing the company's overall exposure to market price volatility. As the delivery month approaches and monthly products become available in the market, the company will further balance its energy position. As the delivery day nears, the company balances its energy position using balance-of-month and day-ahead products. Again, the company balances its average position for these periods. Finally, the company completely balances its position in real-time. This process can result in purchases and sales made for the same delivery period; however, in each step of the process the company is further mitigating its exposure to market price volatility.

Q. Do you agree with any of Mr. Falkenberg's proposed short-term firm adjustments?

A. No. The sales transactions in question were executed at market prices to balance the company's energy position pursuant to risk management policies approved by the company's board of directors. It is inappropriate and misleading to compare prices of sales completed in 2004 to forward market prices from the company's December 2005 official forward price curve. Prudence should be measured based on market prices available when transactions are executed. These transactions were not speculative in nature as Mr. Falkenberg suggests; rather, the company entered into these trades to limit the company's and customers' exposure to market price volatility by balancing the company's west side energy position. Mr. Falkenberg's proposed adjustments are imprudent and speculative in nature as it suggests that the company and customers should carry significant market price exposure from either large long or short energy positions in the hope of timing the market perfectly. Further, the proposed adjustments by Mr. Falkenberg could create significant and undesirable collateral effects (e.g., cost of credit increases and credit agency downgrades) if market timing is less than perfect. The Commission should not adopt Mr. Falkenberg's proposed adjustments.

Q. Do you agree with Mr. Jenks' arguments to disallow the sales?

A. No. Mr. Jenks, like Mr. Falkenberg, misunderstood that the company had a long energy position, and for the same reasons his arguments should not be adopted by the Commission.

Q. Does this conclude your testimony?

A. Yes.

Case UE-179
Exhibit PPL/1300
Witness: Mark C. Mansfield

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Rebuttal Testimony of Mark C. Mansfield

OUTAGES

July 2006

Q. Please state your name, business address and position with the Company.

A. My name is Mark C. Mansfield. My business address is 1407 West North Temple Street, Room 310, Salt Lake City, Utah. My position is Vice President of Safety, Environmental, and Operations Support.

Qualifications

Q. Please describe your education and business experience.

A. I have a Bachelor of Science degree in Mechanical Engineering and a Master of Business Administration degree. I am also a registered professional engineer in the State of Utah. During my career with PacifiCorp, I have served as an Engineer at the Carbon Plant, Maintenance Supervisor at the Carbon Plant, Maintenance Superintendent at the Hunter Plant, and Director of Technical Support for PacifiCorp Generation in Salt Lake City. I have served as the Managing Director of the Naughton Plant, Huntington Plant, and Hunter Plant. In 2006, I became Vice President of Safety, Environmental and Operations Support for PacifiCorp Energy.

Summary of Testimony

Q. Please summarize your rebuttal testimony.

A. My rebuttal testimony responds to certain issues raised by ICNU witness Falkenberg regarding (1) PacifiCorp outage rates, and (2) the treatment of certain generating unit outages. My testimony makes the following points:

- In response to Mr. Falkenberg's testimony about PacifiCorp thermal plant performance, my testimony shows that:
  - PacifiCorp thermal generation performance should not be judged by Mr.

Falkenberg's outage rate in Exhibit ICNU/108.

- No one performance factor should be used alone to assess system performance.
- Even though the coal-fired plant outage rate declined in Mr. Falkenberg's Exhibit ICNU/108, the total net generation output by the plants was improved for the same period.

- In response to Mr. Falkenberg's testimony that certain generating unit outages should be excluded from ratemaking calculations because they were the result of "imprudent operation and management", my testimony shows that:
  - Specific outages identified by Mr. Falkenberg were correctly reported and are not evidence of "imprudent operation and management.
  - Outages that involve personnel or maintenance error should not be excluded from net power cost calculations.
  - Selectively removing forced outages in order to improve PacifiCorp thermal system equivalent availability and capacity factor in the net power cost calculation is unreasonable given that PacifiCorp system equivalent availability factor and capacity factor are already better than the industry average.

PacifiCorp Outage Rates

Q. Is Mr. Falkenberg's method of using outage rates to judge PacifiCorp generating plant performance an accurate indicator of performance?

A. No. No single parameter can be used alone as a measure of overall system performance. Unit ratings, planned outage rate, equivalent forced outage rate, equivalent availability factor, capacity factor, and net generation must all be taken into consideration when measuring system performance.

Q. Mr. Falkenberg uses Exhibit ICNU/108 to conclude "that the increase in outage rates has also lead to the need for additional thermal capacity". What is your opinion?

A. Mr. Falkenberg's Exhibit ICNU/108 is based on the test year data that was used for the 1999 General Rate Case and the current proceeding. The test periods for availability data for these general rate cases are the 4-year period ending 12/31/1998 and the 4-year period ending 9/30/2005. The total actual output from generating units identified in Mr. Falkenberg's exhibit was actually greater for the period ending 9/30/2005 than the period ending 12/31/1998.

PacifiCorp Coal-fired Generating Units		
	4-years Ending 12/31/1998	4-years Ending 9/30/2005
Total Net Generation from Coal-fired units	175,971,000 MWh	177,440,000 MWh

The improvement in output resulted from a positive combination of system performance and market conditions. This is an example of how no single factor can be used to judge system performance. In this case, overall energy output of the thermal units was improved and is indicative of PacifiCorp maximizing the utilization of its generating assets.

Q. Please comment on Mr. Falkenberg's Exhibit ICNU/109.

A. Mr. Falkenberg's Exhibit ICNU/109 uses the outage rates in the net power cost model to show that PacifiCorp "outage rates" are greater than the industry. However, this one factor does not provide a complete picture. The following table provides a more complete comparison of performance using standard NERC availability definitions. The table compares PacifiCorp coal-fired unit performance to the average performance of an equivalent system in the NERC availability database.

	NERC Equivalent System for 4-years Ending 12/31/2004	PacifiCorp Coal-fired Units for 4-years Ending 12/31/2004	PacifiCorp Coal-fired Units for 4-years Ending 12/31/2005
Forced Outage Rate	4.93%	6.25%	5.91%
Equivalent Forced Outage Rate	7.05%[1]	10.02%	10.03%
Planned Outage Factor	7.45%	3.30%	3.47%
Equivalent Availability Factor	84.02%	85.54%	85.47%
Capacity Factor	71.79%	82.29%	82.51%

The table shows that PacifiCorp planned outage factor is better than the industry average. The table also shows that the equivalent availability factor, which results from the combination of forced outages and planned outages, is better than the industry average. Likewise, the capacity factor, which is a measure of actual output, shows that PacifiCorp thermal units are significantly better than the industry average.

Q. Is capacity factor a function of market conditions?

A. Not, entirely. The capacity factor is also a function of how well the company can manage its load profile and generation resources. PacifiCorp has contracts in place that enable the coal-fired generating units to continue to produce energy at near full load levels during off-peak periods. The energy is "stored" in neighboring hydro-electric systems and then made available to the PacifiCorp

[1] The equivalent forced outage rate factor of 7.05% is different from the 9.28% value calculated by Mr. Falkenberg in Exhibit ICNU/109. The 7.05% is based on the industry standard definition for equivalent forced outage rate. Mr. Falkenberg's value of 9.28% is based on a calculation that is comparable to the outage rate factor as used in the GRID model.

system during peak periods. The small spread between capacity factor and equivalent availability factor indicates that most of the available generation is being utilized. This is another example of how PacifiCorp maximizes the utilization of its generating assets.

Q. Are maintenance requirements increased as a result of PacifiCorp's high capacity factors?

A. The net unit output ratings for PacifiCorp units require that the steam generators (boilers) and turbines operate near maximum design capacity when the generating units are at full load. The fact that the capacity factor is within a few percent of the equivalent availability indicates that the generating units are operating near maximum load most of the time the units are connected to the system. Wear rates and stresses increase proportionally, and in some cases exponentially, with load. Maintaining high availability with units operating continuously near maximum capability is a much greater challenge than operating at loads that are in-line with the industry average capacity factors. It is the combination of high capacity factor and higher than industry average equivalent availability that is indicative of good performance.

Exclusion of "imprudent and unreasonable outage costs"

Q. Do you agree with Mr. Falkenberg's conclusion that the selected outage reports provide evidence of "imprudent operation and management of PacifiCorp's resources"?

A. No. Mr. Falkenberg incorrectly infers that imprudent operation and management is evidenced by incidents that involve personnel error. PacifiCorp strives to reduce personnel error by contractors and employees, but it nonetheless occurs, as it does in any business. While personnel error cannot be totally eliminated, the negative impact on production is reduced by emphasizing continuous improvement.

Q. What has been the company's approach to continuous improvement?

A. The process of continuous improvement includes tracking unit availability, analyzing causes of failures, and taking appropriate corrective action. The NERC Generating Availability Database is used to track availability. PacifiCorp has a number of programs that focus on analyzing failures and implementing corrective actions. We do not use a single program such as Six Sigma, but use a number of programs that address specific areas we want to improve. As PacifiCorp identifies areas that need improvement corrective action plans are developed. Examples include our Electric Power Research Institute (EPRI) based boiler tube failure reduction program for our boilers. We have a chemistry management program that uses EPRI cycle chemistry improvement program to address plant chemistry issues. Our high energy piping condition assessment program includes on-going inspections, maintenance and analysis of critical piping issues. We are also in the process of implementing a more structured root cause analysis program for the analysis significant plant incidents. The fact that PacifiCorp maintains an extensive database on unit outages and can provide the reports from these programs for Mr. Falkenberg's review is evidence that PacifiCorp is a prudent operator.

Q. How does PacifiCorp's record with respect to personnel errors compare with that of other utilities?

A. The percent equivalent availability factor attributed to personnel error in the industry is small. The percent equivalent availability factor attributed by PacifiCorp to personnel errors is in-line with the industry.

PacifiCorp Coal-fired Generating Units		
	Equivalent Coal-fired NERC Industry Level Data	PacifiCorp Coal-fired Plants
Percent Equivalent Availability Factor Lost Due to Personnel Error NERC Codes 9900-9940	0.06%	0.05%

Q. Mr. Falkenberg points out that outages he has determined to be due to personnel or maintenance errors were not reported to NERC as being due to personnel or maintenance error. How does PacifiCorp determine how to report outage causes?

A. PacifiCorp plant personnel determine the cause and duration of each derating and forced outage and enter that information into the PacifiCorp Availability Information System (AIS) database. The AIS data base uses standard NERC cause codes. Each incident is coded with the most appropriate NERC cause code based on available information. The information in the AIS database is reported to NERC.

Q Is there any reason to believe that PacifiCorp intentionally under reports the number of incidents caused by personnel error?

A. Absolutely not. Accurate information is essential to good analysis of the causes of deratings and outages. Plant personnel determine the most appropriate code using available information. The data entered into the database is reviewed and validated monthly for consistency and accuracy.

Q. **Mr. Falkenberg identifies a number of specific outages that he claims were due to "personnel or maintenance errors or other avoidable problems" that were attributed to another cause. What is your perspective on these outages?**

A. Plant personnel assigned the appropriate NERC cause code to each outage given the nature of the event. Personnel error or maintenance error may have played a part in the incidents; however, that does not mean the incidents were incorrectly coded or reported. PacifiCorp uses the NERC guidelines for reporting into the NERC Generating Availability Data System. The guidelines recommend selecting the code which best describes the cause or component responsible for the event. The NERC guidelines specifically recommend to not assign the cause to an auxiliary component or operation that triggered the failure of a major component or system. Plant personnel select the appropriate code based on available information about each event. In general, the maintenance error codes or operator error codes are attributed to incidents where the outages are a direct consequence of operator or maintenance action. These codes would not necessarily be applied to an incident in which a root cause analysis indicated an equipment failure resulted from a chain of events initiated by personnel error.

Q. **Can you provide an example?**

A. Yes. Mr. Falkenberg questioned the characterization, or NERC code, that was assigned to several outages. I will use the incident that occurred at Hunter Plant on Unit 1 on November 1, 2002, as an example. This outage was caused by a steam leak in a circumferential weld in the hot reheat piping. The failure occurred in the original manufacturer's shop weld. PacifiCorp's subsequent metallurgical failure analysis identified "…no metallurgical or compositional defects which could have contributed to the premature failure of this weld…". An unusual welding procedure was used, but the procedure met code requirements and there was no evidence linking the failure to this procedure. Since 2003, an industry awareness of this problem has developed and the issue is under evaluation by the Electric Power Research Institute Program 87. PacifiCorp has a very proactive critical piping condition assessment program. As a result of this failure, PacifiCorp has modified its inspection protocol for critical piping to identify damage resulting from this mechanism. The outage was correctly recorded as an "Unplanned (forced) outage". Plant personnel coded the failure as a "leak" in the "reheat steam piping up to turbine stop valves". This was in-line with the NERC guideline to assign the cause of the event to the major component or system that is responsible for the event. It should be noted that the purpose of the NERC Generation Availability Data System is to track outage statistics and is not intended to be a root cause analysis tool, although the data within the database may be used as a resource for a particular root cause analysis.

Q. Mr. Falkenberg claims that outage incidents reported to NERC as being due to operator or personnel errors contribute to imprudent and unreasonable costs. Do you agree?

A. No. Personnel errors alone are not an indication of imprudence. PacifiCorp records the cause of each outage incident as accurately as practical in the

PacifiCorp Availability database, which is essential to having good information for making decisions on how to improve plant performance. PacifiCorp recognizes that personnel error does contribute to some outages. PacifiCorp is committed to minimizing these incidents by maintaining an emphasis on continuous improvement.

Q. Do you agree that selected outages should be removed from calculation of net power costs?

A. No. PacifiCorp's equivalent availability factor and capacity factor are better than industry averages.

Four-year period ending	NERC Equivalent System		PacifiCorp Coal-fired System	
	Equivalent Availability Factor	Capacity Factor	Equivalent Availability Factor	Capacity Factor
2004	*84.02%*	*71.79%*	*85.54%*	*82.29%*
2005	*Data not available*		*85.47%*	*82.51%*

PacifiCorp coal-fired plant capacity factor is only 3 percent less than the equivalent availability which indicates that the coal fired units operate near the maximum available capacity all the time. Also, the small spread between equivalent availability factor and capacity factor compared to the average industry spread shows that PacifiCorp is able to achieve a higher than average utilization of its thermal generating assets. Mr. Falkenberg recommends that certain outages be removed in order to further "improve" the system availability and capacity factor and consequently reduce net power costs. Mr. Falkenberg's recommendation is unreasonable and unwarranted given that PacifiCorp's equivalent availability and capacity factors are better than industry averages.

Q. Please summarize the Company's position regarding the removal of outages from the availability calculations for ratemaking purposes.

A. All outages should remain in the availability calculations used in the net power cost model. PacifiCorp is focused on continuous improvement. Our objective is to maximize the generation from the thermal units with attention to safety and environmental compliance. Consequently, PacifiCorp maintains a constant emphasis on minimizing deratings and outages. Even so, it is not possible to eliminate all personnel error. Removing outages attributed to personnel error from the net power costs model inputs will result in unreasonably high thermal unit output. The historic forced outage rate should be the basis of the outage rate used in the net power cost model.

Q. Does this conclude your rebuttal testimony?

A. Yes.