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

A. Yes.

Purpose and Summary

Q. What is the purpose of your testimony?

A. My testimony has two parts, a Transition Adjustment Mechanism (TAM) update section and a rebuttal section. In the TAM update section, I provide contract and forward price updates to the Company's net power costs. In the rebuttal section, I address the following issues:

- The data corrections proposed by the Company for non-owned generation operating reserves.
- The proposed adjustments from Staff and intervenor direct testimony that the Company will accept, which include Mr. Wordley's proposed operating reserve, Carbon adjustment and recommendation on stochastic modeling; Mr. Falkenberg's proposed adjustments on combustion turbine (CT) reserve capability, west-to-east reserve transfer, uneconomic CT operation and planned outages for the Gadsby CT component of the adjustment; and Mr. Jenks' proposal to provide benchmark curves for the Company's forward price curves for electricity and natural gas.
- The proposed Staff and intervenor adjustments that the Company contests, which include Mr. Wordley's wholesale margin adjustment; Mr. Falkenberg's proposed adjustments on extrinsic value of call options, excess reserve allocation, hydro modeling (Vista), station service, reverse

Dave Johnston 3 update, Cholla 4 minimum and planned outages for the Currant Creek portion of the adjustment; Mr. Jenks' proposal to reject the Company's the latest version of the GRID production dispatch model version 6.1 instead of version 5.3 and his opposition to the Hermiston loss correction.

Q. Using the TAM updates, data corrections and the adopted adjustments, have you recalculated the Company's forecast net variable power costs (NVPC) for 2008?

A. Yes. Total company net power costs are now $979.5 million, a reduction from the NVPC forecast of $1.002 billion in my direct testimony. PPL Exhibit 205 summarizes the cost impact of the TAM updates, data corrections and adopted adjustments.

I. TAM - Net Power Costs Updates

Q. Please describe the TAM net power costs updates.

A. The net power costs updates include the following contract data and forward price curve updates:

- Utah Irrigation demand side management program – net power costs are updated to include this new program,
- Blanding purchase power – net power costs are updated to include this new contract,
- Black Hills wholesale sale – the contract was updated to include a price update,
- Bonneville peaking purchase – the contract was updated to reflect a new

lower price, an operational limit that allows Bonneville to restrict return deliveries during certain periods and an operational benefit that allows the Company to return an additional 100 megawatts above the contract demand level of 575 megawatts from March through October of each year during light loads hours,

- Grant County purchase - the Grant Reasonable portion of the contract was updated to reflect new information from Grant County and the Grant Meaningful contract was updated to reflect the June 2007 forward price curve,
- Short-term firm – net power costs were updated to include new wholesale sales and purchase power transactions completed since the original April filing,
- Goodnoe project contract – the size of the project was lowered from 112 megawatts to 94 megawatts to reflect the final design from two farms to one farm,
- Coal contracts – net power costs were updated to reflect changes related to mine plan updates and actual cost increases,
- TransAlta exchange – net power costs were updated to include the new location exchange contract that provides the Company energy at our Paul substation, which the Company returns at Mid Columbia,
- Oregon Environmental Industries purchase - net power costs were updated to reflect this new qualifying facility purchase power contract,
- Schwendiman purchase – the expected start date of this qualifying facility

contract was extended until March 2008 to reflect project delays,

- June 2007 forward price curve – net power costs were updated to reflect the Company's new forward price curve,
- New gas swaps - transactions were updated and include the impact of the June 2007 curve,
- Bonneville wheeling contracts – prices were updated to reflect the latest Bonneville projections,
- Hydro generation – was re-shaped to reflect the impact of the June 2007 forward price,
- Douglas Wells purchase – the contract was updated to reflect new cost estimates provided by the project owner,
- AMP Resources – the contract was removed from net power costs because it is now not expected to be in-service during the test year, and
- Roseburg Forest Products California – the contract was removed from net power costs because of the increased uncertainty at this time that the contract will be executed.

II. Rebuttal

A. Data Corrections

Q. Please describe the corrections included in the Company's net power costs filing.

A. As shown on PPL Exhibit 205, this filing includes corrections for non-owned generation operating reserves located in the Company's east control area, Hermiston line losses and natural gas swaps. The operating reserve adjustment corrects the amount of generation expected from the Tesoro company generator. Tesoro is a retail customer located in Utah that has onsite generation. Because they are located in the Company's east control area, the Company is required to carry contingency reserves on their behalf. The correction reduces the expected level of Tesoro generation and the associated reserve requirement. The Hermiston line loss correction includes line losses that were inadvertently excluded from the line loss study used to develop the load forecast for this case. The natural gas swap correction incorporates sales transactions that were originally included as purchases as a result of incorrect labeling in the system which tracks the data. In total these corrections ***decrease*** proposed net power costs by $15.8 million total Company.

Q. Has Mr. Jenks opposed certain of these corrections?

A. Yes. Mr. Jenks recommended rejection of the Company's proposed correction for Hermiston line losses on the basis that it was outside the scope of the TAM. The Company believes that data corrections are within the proper scope of the rebuttal testimony in this case. The Company has always filed corrections to known errors in its rebuttal case, whether these errors work in customers' favor or the Company's, and it made such data corrections in its last TAM rebuttal filing in UE 170. In this case, as just noted, on a net basis the corrections work in customers' favor.

B. Uncontested Adjustments

Operating Reserve Adjustment

Q. Do you agree with the operating reserve correction proposed by Mr. Wordley?

A. Yes. As I explained above, this correction should be adopted along with the other corrections included in my rebuttal testimony.

Carbon Generation Plant

Q. Please explain the Carbon generation plant adjustment proposed by Mr. Wordley.

A. The proposed adjustment increases the Carbon plant capacity factor from 70 percent in the Company's April 2007 filing to an 80 percent capacity factor. This would result in lower net power costs as a result of additional wholesale sales and or decreased market purchases.

Q. Do you agree with the adjustment?

A. Yes. While the Company is willing to adopt the proposed mechanics of the adjustment, Carbon's exact new capacity factor will be a function of the variables that are updated in the TAM. For example, the Carbon capacity factor in this TAM update is now 74 percent after incorporating the adopted adjustments. As additional updates are made the capacity factor may change further. Therefore, the monetary impact of the Carbon adjustment should be finalized with the Company's final TAM update on November 14, 2007, so the adjustment matches final updated net power costs. Based upon the current TAM filing, the proposed adjustment would reduce net power costs by approximately $4.8 million on a total company basis.

Stochastic Net Power Costs Modeling

Q. Is the Company willing to accept Mr. Wordley's recommendation to file a written report to the Commission on the feasibility of net power costs' estimation through the use of stochastic modeling by September 1, 2007?

A. Yes, with one qualification on timing. The Company has completed its analysis of stochastic modeling and it is now working on internal review of the results and preparation of the summary report. To finish these tasks and incorporate any new developments from this case, the Company proposes to file its stochastic modeling report 15 business days after the issuance of the final order in this case.

CT Reserve Capability

Q. Do you agree with Mr. Falkenberg's proposal to increase the quick start capability of the Gadsby and West Valley CTs from 20 megawatts to 40 megawatts?

A. Yes. The Company agrees to incorporate the model change in future updates in this case. In this update, the proposed adjustment reduces net power costs by approximately $0.2 million total Company. The final impact of this change will be based on the Company's final net power costs update.

W-E Reserve Transfer

Q. Please explain the west-to-east reserve transfer adjustment proposed by Mr. Falkenberg.

A. The proposed adjustment would incorporate the transmission capability to transfer up to 100 megawatts of ready reserves from the Pacific–West to Pacific–East control areas. Mr. Falkenberg believes the capability should be included in the model even though there are adequate ready reserves in the east, because there are times when the transfer capability may still provide a benefit. The proposed adjustment would reduce net power costs by $2.99 million total company.

Q. Do you agree with the proposed adjustment?

A. I agree with the general recommendation to leave the transfer capability turned on in GRID so that any benefits that may arise can be captured in those limited times when it may be of use. I do not agree with ICNU's quantification of the value of this adjustment. In this update, for example, the proposed adjustment reduces net power costs by approximately $0.2 million total Company. The final impact will be included in the Company's final TAM update.

Uneconomic CT Operation

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

A. The proposed adjustment removes West Valley from GRID because the model incorrectly dispatched this resource when it was not the lowest cost resource option. The adjustment would reduce net power costs by $0.74 million total company.

Q. Do you agree with the proposed adjustment?

A. The Company accepts the mechanics of the proposed adjustment and will incorporate it in the remaining GRID updates if removal of West Valley results in lower net power costs. In this update, the adjustment reduces net power costs by $1.6 million total company.

Planned Outages

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

A. The proposed adjustment uses the 48-month average of actual planned outages for the Gadsby and West Valley CTs and the Currant Creek combined cycle combustion turbine.

Q. Do you agree with the proposed adjustment?

A. I agree with the portion of the adjustment related to the Gadsby CTs because the Company has 48 months of actual maintenance information. The adjustment related to West Valley units may no longer be necessary since the unit may be excluded in the final update if doing so lowers the net power costs. I do not agree with the proposed adjustment for Currant Creek. The Company does not have 48 months of actual information since the plant has only been in service since March 2006. I will therefore discuss Currant Creek below as I discuss contested adjustments. In this update, the Gadsby CT adjustment reduces net power costs by an immaterial amount.

Forward Price Curve Benchmark

Q. Please explain Mr. Jenks' recommendation.

A. Mr. Jenks proposes that the Company include at least two independently-produced forward electricity and natural gas prices curves with its final TAM filing. He also recommends that the Company explain any deviation of five percent or greater in the filing. He suggests that this would provide a check on the reasonableness of the Company's forward price curves.

Q. Do you agree with this recommendation?

A. Yes, with modifications. The Company is willing to make available its forward price curve, along with the independent third-party forward pricing information that the Company uses, for the one-year test period for the final TAM net power costs update. In this case, for example, PacifiCorp would make available its forward price curve for 2008, along with the independent third-party forward price information for 2008 it relied upon to determine this curve. The information will be made available on a confidential basis under the terms of a protective order. However, if the Company's curve and the independent third party pricing information vary by five percent or more, the Company will not be able to explain the difference, because we do not have access to third party data or models. Based on past experience, however, the Company does not believe that the prices will vary by more than five percent.

B. Contested Adjustments

Staff Adjustment - Wholesale Margin

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

A. Mr. Wordley proposes to adjust the 2008 wholesale margin and volume between short-term firm and non-firm sales and purchases included in the Company's filing to reflect the alleged value of the differences between the actual historical volume and margins for the 12-month historical periods ended June 30, 2003, March 31, 2004, and December 31, 2006, and the wholesale volumes and margins modeled in GRID for UE 134, UE 147 and UE 170. He believes the adjustment is appropriate because actual volumes and margins during the referenced periods were different than forecast in the Company's GRID production dispatch model in UE 134, UE 147 and UE 170.

Q. What is the value of Mr. Wordley's proposed margin adjustment?

A. The proposed adjustment reduces net power costs by approximately $66.37 million total Company and $17.24 million on an Oregon basis.

Q. Why does the Company object to Mr. Wordley's proposed adjustment?

A. Mr. Wordley's adjustment would unfairly and unreasonably offset a significant portion of the power cost increases in this case, which are based upon objectively verifiable contract and market price updates. The adjustment has many problems:

- It is inconsistent with the Commission's recent rejection of Staff's extrinsic value adjustment in UE 180, which recognized that system value should be captured by comprehensive modeling changes, not one-factor adjustments.
- It is poor regulatory policy, unjustifiably imputing an actual cost model into a normalized ratemaking paradigm.
- It is based on the incorrect premise that power costs are overstated because they do not reflect actual short-term transactions.
- It overstates the value of the margin on increased wholesale transactions.
- It is poor regulatory policy because it systematically mismatches costs and benefits.

UE 180 Order

Q. Is this the first time that Mr. Wordley has suggested this adjustment?

A. No. Mr. Wordley first proposed this adjustment in UE 116. In that case, he asserted that the margin adjustment was necessary because the Company's power cost model in use at that time, PD/Mac, was not an hourly cost model and failed to capture the flexibility of the Company's resource portfolio. (Staff/200, Wordley/5-8). The adjustment was resolved in that case through a Stipulation on power costs where the Company agreed to develop an hourly power cost model.

Q. After the Company developed GRID, an hourly power cost model, did Mr. Wordley change his rationale for his margin adjustment?

A. Yes. In UE 179, Mr. Wordley proposed the same adjustment, this time claiming that it and a closely related adjustment for extrinsic value were necessary until the Company developed stochastic power cost modeling:

> "If the company successfully implemented stochastic power cost modeling, there may no longer be a need for staff's proposed margin and extrinsic value adjustments. Stochastic power cost modeling would mitigate the concerns regarding the primary inputs to GRID discussed earlier, and would help capture the impact on power costs of the sales and purchase transactions currently not captured by GRID and the option (extrinsic) value of the undispatched capacity of PacifiCorp's flexible resources." (Staff/100, Wordley/9).

These adjustments were resolved in UE 179 through a Stipulation that settled all issues in the case.

Q. Did Mr. Wordley propose similar adjustments in PGE's last rate case, UE 180?

A. Yes. Mr. Wordley proposed an extrinsic value adjustment:

> "Until PGE develops and implements stochastic power cost modeling, Staff recommends that the Commission adjust the NVPC estimates for the extrinsic value of PGE's resources to ensure that customers receive the benefits from the Company's flexible power resources for which they are already paying in rates." *In re Portland General Electric*, Order No. 07-015 at 11.

Q. How did the Commission resolve this adjustment?

A. The Commission rejected this adjustment on the basis that it was unreasonable to review only one factor in considering the overall accuracy of PGE's power cost model (one that would lower NVPC), especially when the model generally underestimated NVPC. The Commission also directed PGE to study stochastic modeling and file a report on its potential for use in forecasting NVPC. *Id.* at 11-12.

Q. Are Staff's adjustments for wholesale margin and extrinsic value related?

A. Yes. Staff has historically argued for both margin and extrinsic value adjustments in PacifiCorp's power cost filings. In essence, Staff's wholesale margin adjustment is a one-sided approach to capturing extrinsic value, where benefits are counted without consideration of the expense incurred to obtain the benefit.

Extrinsic value is the benefit created through the flexibility of a resource and the underlying volatility of the commodities. For example, 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. The extrinsic value of that flexibility is generated through additional wholesale sales made possible by incremental generation or through the avoidance of higher priced wholesale purchases.

The potential benefits of extrinsic value are covered in the proposed wholesale margin adjustment. What is never captured in the margin adjustment, however, is the additional fuel expense incurred to generate the extrinsic value. Thus, the margin adjustment is a deviation from a general extrinsic value adjustment, one that is incomplete and one-sided.

Q. Does the Commission's Order rejecting the extrinsic value adjustment in UE 180 apply equally to the margin adjustment in this case?

A. Yes. As just noted, Staff has historically argued for both margin and extrinsic value adjustments in PacifiCorp's power cost filings on the basis that PacifiCorp's power cost model (first PD/Mac and then GRID) systematically overstated power costs by not capturing these values. The Commission's conclusion that PGE's power cost model did not overstate power costs by failing to account for extrinsic value applies even more clearly to PacifiCorp's model and the margin adjustment. That is, while the GRID model does not account for actual volumes of short-term purchases and sales, this does not result in a systematic overstatement of power costs—in part because, as noted below, PacifiCorp's actual, historic margins on its short-term purchase and sale transactions are negative on an average basis.

Additionally, the Commission in UE 180 rejected a single-factor approach, implicitly recognizing that a deterministic power cost model fails to capture other values that might partially or fully offset an extrinsic value adjustment. Instead, the Commission recognized that the better course was to work toward a new power cost model that more comprehensively captures the costs and benefits of stochastic volatility.

This reasoning applies with full force to Staff's margin adjustment. Rather than adopting this adjustment that captures the benefits of system cost variation without considering the significant costs of system variation, the Commission should adopt Staff's recommendation that PacifiCorp file the results of its stochastic power cost analysis, working toward development of a power cost model that fairly and accurately captures the system values Staff has attempted to quantify in its extrinsic value and margin adjustments.

Inconsistency with Normalized Ratemaking

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 this accurate?

A. No. These benefits are all captured on a deterministic basis by GRID. The system dispatch portion of the model is a linear program that optimizes the Company's system with perfect foresight based upon market prices, load requirements, resource characteristics and transmission availability. This optimization includes 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. Mr. Wordley claims that his adjustment is reasonable because "there is considerably more variation and interaction, between actual loads, market energy prices, thermal plant availability and hydro generation than what is modeled in GRID." Does the actual variability justify the adjustment?

A. No. The existence of variability between forecast and actual short-term wholesale transactions does not justify adoption of what is essentially an historical true-up adjustment for prior unrelated periods within a power cost model that is otherwise based upon normalized forecasts. If the Commission adopted the Staff's margin adjustment, consistency and matching principles would require adoption of similar true-ups (without deadbands or sharing) for other cost items with actual results that generally vary from normalized forecasts, such as hydro generation, loads and forced outages. This, in turn, suggests adoption of a power cost adjustment mechanism to comprehensively true-up forecasted power costs to actual power costs, a very different power cost model from the one now approved for PacifiCorp in Oregon.

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

A. Yes. This is a characteristic of any deterministic 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. Even with a stochastic model, the volumes may still be lower than actual results because a model can only capture the variation determined by the given statistical properties. 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., up to the actual time of delivery. Additionally, products available in the market are not always a good fit to balance resource requirements, which also leads to higher actual volumes. As a result, actual balancing generates higher volumes than GRID or other deterministic models.

PacifiCorp's Power Costs Are Not Overstated

Q. Mr. Wordley asserts that his adjustment is necessary to ensure that power costs are not systematically overstated. Is this true?

A. No, the opposite is true. The results from the Company's last two rate cases demonstrate (1) that power costs in rates were generally close to the Company's actual costs; and (2) application of the proposed margin adjustments Mr. Wordley has calculated for these cases would have produced a significant understatement of power costs.

Approved net power costs in UE 147 were $610.7 million, based on a forecast test year of twelve months ended March 2004. Actual net power costs for that test year were higher, $646.6 million. Mr. Wordley's margin adjustment, however, asserts that GRID underestimated wholesale margins in UE 147 by $22.2 million, so that power costs in UE 147 should have been $588.5 million—or $58.1 million below the $646.6 million actual net power costs incurred for the UE 147 test period.

This same problem exists for the UE 170 test period except the problem is even worse. In UE 170, the Company's filed net power costs were approximately $814 million. The wholesale margin adjustment Mr. Wordley calculated for UE 170 is $102.5 million. The actual net power costs for 2006 were $783.2 million. If the filed net power costs were adjusted to reflect Mr. Wordley's margin adjustment, authorized net power costs would have been $711.5 million or $71.7 million below actual costs.

Overstatement of Value of Margin

Q. How is Mr. Wordley defining wholesale margin?

A. Mr. Wordley defines wholesale margin as the average price per megawatt hour of short-term firm and nonfirm sales, less the average price per megawatt hour of short-term firm and non-firm purchases.

Q. Do you agree with this definition?

A. No. Typically, a wholesale margin is connected to wholesale trading, where a company buys energy that it intends to sell to generate a margin. Mr. Wordley is improperly applying the concept of margin to the Company's short-term transactions, the majority of which are balancing transactions where the Company is either buying or selling energy to cover a short position or to reduce a long position to balance the system.

Q. What margin does Mr. Wordley propose in his adjustment and how does this compare to the Company's historical wholesale margins?

A. Mr. Wordley's wholesale margin adjustment would produce a wholesale margin of $5.43 per megawatt hour if adopted, based on the Company's filed case, which now includes a $2.92 margin. In comparison, actual margins per megawatt hour for calendar years 2002 through 2006 were ($2.41~~2~~), $.08, ($3.03), ($4.75) and $1.59.[1] Thus, the adjustment does not reflect the actual information upon which it purports to be based.

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[1] The following are the total sales and purchases on which these margins are based:
2002: **Sales**–$617,419,752; Energy–~~$~~22,627,158 MWh; Average Price–$27.29
Purchases–$678,978,961; Energy–22,859,398 MWh; Average Price–$29.70
2003: **Sales**–$740,392,188; Energy–~~$~~18,814,901 MWh; Average Price–$39.35
Purchases–$656,264,254; Energy–~~$~~16,710,040 MWh; Average Price–$39.27

Mismatches Inherent in the Margin Adjustment

Q. Does the proposed adjustment create significant problems with the mismatch of costs and benefits?

A. Yes. There are at least three ways in which the proposed wholesale margin adjustment violates the regulatory principle of matching in a manner that is prejudicial to PacifiCorp.

- There are different resources included in the actual results than in GRID filed net power costs. Similarly, certain resource costs are excluded in the normalized net power costs even though these costs were incurred to generate actual wholesale sales or offset actual wholesale purchases.
- There are different resource planned maintenance schedules in actual operations than were in GRID due to the 48-month normalization method.
- The adjustment combines general rate and TAM case results, even though the TAM updates wholesale transaction volumes throughout the year, leading to a more accurate forecast, while a rate case does not.

Q. Does the development of the wholesale margin adjustment from Dockets UE 170 and UE 134 violate the regulatory principle of matching?

2004: **Sales**–$931,783,050; Energy–$21,950,084 MWh; Average Price–$42.45
Purchases–$906,980,291; Energy–$19,940,246 MWh; Average Price–$45.48
2005: **Sales**–$1,224,842,304; Energy–$22,669,497 MWh; Average Price–$54.03
Purchases–$1,093,436,691; Energy–18,601,461 MWh; Average Price–$58.78
2006: **Sales**–$1,846,626,450; Energy–$34,387,824 MWh; Average Price–$53.70
Purchases–$1,518,140,121; Energy–$29,132,315 MWh; Average Price–$52.11

A. Yes. The GRID data for UE 170 and UE 134 is not comparable to the actual data for those test years due in part to the treatment of new resources under Oregon's used and useful statute, ORS 757.355.

Q. Please explain.

A. GRID modeled net power costs for UE 170 did not include the impact of the 525-megawatt Currant Creek combined cycle combustion turbine or the 100-megawatt Leaning Juniper wind project because they were not in-service prior to the start of the test year. However, both resources are in actual net power costs because Currant Creek was placed in service in March 2006 and Leaning Juniper was placed in service in September 2006. As a result, actual net power costs include approximately 1.8 million megawatt hours of below market price generation used to make wholesale sales and or avoid market purchases that were not included in UE 170 GRID calculated net power costs and not being paid for by Oregon customers. Actual costs also include $58 million of natural gas fuel expense that is not captured in the margin adjustment even though the benefit of the generation is included in the margin adjustment. A similar situation exists for UE 134 where GRID modeled net power costs did not include the 200 megawatts of West Valley combustion turbines, which started in June 2002 and were included in actual net power costs.

Q. Could you discuss the mismatch inherent in the adjustment related to plant maintenance?

A. Yes. Normalized ratemaking uses a 48-month average for planned maintenance. However, in a given year actual planned maintenance varies from the 48-month average because thermal plant overhaul schedules change from year to year. In a situation where the actual planned maintenance is less than the 48-month average, more generation will be available to make additional wholesale sales or reduce wholesale market purchases, which is incorporated in the wholesale margin calculation. But, there is also a significant level of fuel expenses associated with the additional generation benefit that is not included in the wholesale margin adjustment—or elsewhere in PacifiCorp's rates. It is also worth noting that the use of actual forecast maintenance is not allowed in the TAM net power costs calculation, yet it is included in the wholesale margin adjustment. The same is also true for variation in other system elements, such as hydro generation.

Q. Please explain.

A. If we have a good hydro year and the Company is able to make more wholesale sales, the entire benefit of those sales is included in the wholesale margin adjustment. Conversely, if the Company has a bad hydro year and generates with higher cost thermal resources, the only recourse the Company has to collect the higher thermal costs is through a deferred accounting application or by seeking interim rate relief. The Commission has made clear that it will not allow a Company such relief absent extraordinary circumstances.

Q. Earlier you mentioned that there was a problem with the type of cases Mr. Wordley uses to develop the wholesale margin adjustment. Please explain.

A. Dockets UE 134 and UE 147 were not TAM filings and therefore did not include the data updates that the TAM process includes. As a result, net power costs for those dockets have a significantly lower volume of short-term transactions than

TAM filings do because the TAM updates incorporate new transactions for the 2008 test year up through October 31, 2007. For example, the Company's April 2007 filing in this docket, which would be similar to the UE 134 and UE 147 filings, included 16.6 million megawatt hours of sales. The net power costs update filed with this rebuttal includes 26.8 million megawatt hours of sales and will be updated again for transactions completed by October 31, 2007. The point here is that since Mr. Wordley's wholesale margin adjustment is in large part based on the volume difference between GRID net power costs and actual net power costs, it is not appropriate to use the comparison between GRID results from UE 134 and UE 147 with the corresponding actual results for this TAM because they were not updated as are TAM net power costs.

Q. What is your recommendation to the Commission?

A. The proposed margin adjustment should be rejected.

ICNU Adjustment - Extrinsic Value Call Options

Q. Please explain Mr. Falkenberg's proposed adjustment for call options.

A. The proposed adjustment imputes extrinsic value for five call option contracts included in GRID. Mr. Falkenberg believes this is reasonable because it will prevent a situation where customers pay for the costs of the contracts and receive no benefits. The proposed adjustment would reduce net power costs by $5.27 million total Company.

Q. Do you agree with the proposed adjustment?

A. No. This is not a case of customers not receiving a benefit. Customers receive the benefit of reliable service and the benefit of energy dispatch when it is economic. As I explain, not all the call option contracts meet the Commission criteria for allowing imputation of extrinsic value, because some of them lower the net power costs as dispatched in GRID. And while the option contracts are not providing an energy dispatch value at this time, that could change with future TAM updates.

Q. How do call option contracts ensure reliable service?

A. The contracts in part ensure reliable service by providing physical delivery of energy into our Utah load area during periods of increased demand and / or transmission constraints when prices are higher. So even if the contracts are not dispatched purely in GRID, they can provide customers a real benefit in the event of a change in the Company's system.

Q. Is the proposed adjustment consistent with Commission precedent?

A. No. While Mr. Falkenberg makes reference to the Commission's decision in UE 180, he expands the impact of that decision by suggesting that unless a contract energy component provides enough benefits to cover the premium, extrinsic value should be imputed. This is definitely not what the order adopted. In the pertinent part of that order the Commission states:

> "The Super Peak and Cold Snap contracts can be distinguished from the Company's other resources because they **do not dispatch at all in the Monet run** used to estimate test year power costs. Without an extrinsic value adjustment, customer rates would **include all of the costs and none of the benefits**." *In re Portland General Electric*, Order No. 07-015 at 13.

Nowhere in the order does the Commission state that the energy portion of the contract must provide enough benefit to cover the cost of the premium. In fact, Mr. Falkenberg's logic doesn't make sense for an option contract purchased to provide reliability and capture value when market prices justify dispatch.

Q. Please explain.

A. When the Company buys an option contract, the Company looks for out-of-the-money contracts that have a lower premium as a means of providing reliability while keeping costs low, because the contracts are not expected to be dispatched all of the time. If the Company were to buy in-the-money option contracts, the premium and overall cost would be higher because of the expectation that they would be dispatched most of the time.

Q. Mr. Falkenberg claims that the removal of the contracts lowered net power costs. Is that the case in the Company's updated net power costs?

A. No. Two of the contracts used in Mr. Falkenberg's adjustment lower the net power costs when they are dispatched and would ~~reduce~~increase net power costs if removed. Therefore, customers are receiving a benefit from these contracts in addition to the reliability benefit they receive.

Q. What is the impact of the other three call option contracts?

A. When the remaining call option contracts used in Mr. Falkenberg's adjustment are removed from the GRID calculation, the Company's net power costs decrease. Therefore, the Company proposes to remove these contracts from the Company's final TAM calculation as long as that is still the case when the final update is completed. If their removal does not lower net power costs, they should not be removed.

Q. What other adjustment may the Company make regarding the call option contracts?

A. Following the same logic, the Company may also remove the premium payments when those in-the-money contracts are not dispatched. At the current time, removing those three contracts and a portion of the premium payments of the other two contracts, lowers net power costs by approximately $5.3 million on total Company basis. The value of the adjustment will be based on the Company's final net power costs update.

ICNU Adjustment - Excess Reserve Allocation

Q. Please explain Mr. Falkenberg's proposed adjustments for excess reserve allocation.

A. Mr. Falkenberg proposes to adjust reserve requirements for a variety of reasons. Those reasons include his belief that the GRID regulating margin calculation is not consistent with a Western States Coordinating Council white paper, is not consistent with the Company's actual practice, and what he says is a more serious issue whereby GRID allocates more capacity to reserves than required to meet the requirements. The proposed adjustments would reduce net power costs by $14.9 million total Company.

Q. Do you agree that the operating reserve requirements as modeled in the Company's April 1, 2007 filing were overstated?

A. Yes, but not for the reasons suggested by Mr. Falkenberg. As noted above, the Company had an error in its operating reserve modeling, which has been corrected in the net power costs update filed with my rebuttal testimony. This is the same adjustment that was proposed in Mr. Wordley's testimony.

Q. Why do you contest Mr. Falkenberg's excess reserves adjustment?

A. The adjustment double counts contractual reserves and assigns a cost to the excess reserves when there is no cost because they are derived from the unused capacity of the Company's western hydro units.

ICNU Adjustment - Regulating Reserve

Q. Mr. Falkenberg criticizes GRID's regulating reserve calculation. Does he propose any adjustment on this basis?

A. No. He does not propose a specific adjustment.

Q. Mr. Falkenberg makes the point that the regulating reserve requirement is "performance based." From this, he concludes that any measure of the regulating reserve 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 preclude utilities from developing 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 the NERC performance criteria.

Q. Mr. Falkenberg states that the Company's method of calculating regulating margin in GRID is not comparable to the methods identified in the Western Systems Coordinating Council white paper included in his testimony as ICNU Exhibit/104. Do you agree?

A. No. The Company's method is similar to Method B, the load following method discussed on pages 9 and 10 in the white paper. Method B calculates the regulating margin requirement as the sum of the 10 minute forecast load change plus the 10 minute schedule variation in ramps and dynamic schedules (interchange) plus a function in ACE (difference between scheduled interchange and actual interchange). GRID calculates regulating margin requirement as the hourly change in net area load, which includes interchange divided by 2. The main difference is that GRID does the calculation on an hourly basis instead of 10 minute increments. Since GRID uses an average approach, it is conservative because it does not capture the 10 minute spikes and drops in load. Further, as I explained in my direct testimony, GRID does not capture the ramping requirements associated with wind generation variability.

Q. Has the Company recently successfully litigated the issue of regulating reserve calculation with ICNU?

A. Yes. The issue was litigated in the Company's most recent Washington case Docket No. UE-061546. The order for that case was received June 2007 and the issue was decided in the Company's favor.

ICNU Adjustment - Hydro modeling

Q. Mr. Falkenberg raises multiple issues with the hydro generation data used by the Company in this filing. Starting with the discussion of correlation among the hydro facilities, how do you respond?

A. In the simplest of terms, I agree with Mr. Falkenberg's statements regarding the correlation (or lack thereof) among the individual hydro plants and river systems.

However, I disagree with his conclusion and his mean hydro adjustment calculation.

The Company is aware that it would be a relatively rare occurrence if the entire region including the Mid-Columbia River and the Utah plants would be either significantly dry or wet contemporaneously. "Dry," or 75 percent exceedence level, represents a reasonable lower bound for hydro generation and "wet," or 25 percent exceedence level, represents a reasonable upper bound. The Company believes that most of the actual outcomes will fall between the upper and lower boundaries.

As Mr. Falkenberg mentions, in the Company's first use of VISTA, greater extremes and more points across a range of possible outcomes were included. Upon reviewing the data, we found that when combined for all river systems, these extremes were greater than any year in the historical record. That discovery prompted the move to 25 percent and 75 percent exceedence levels. On individual river systems the 25 percent / 75 percent levels are roughly equal to plus and minus one standard deviation of the annual total generation. When all of the river systems are combined, the range is closer to plus and minus two standard deviations—a reasonable range of possible hydro generation.

Q. After review of the associated work papers, it appears that much of Mr. Falkenberg's recommended hydro adjustment comes down to the use of the mean rather than the median as the best measure of the central tendency of hydro generation. Please explain why PacifiCorp supports the use of the median value for hydro generation.

A. Both mean and median are legitimate statistics used to define the central tendency of an underlying distribution. Mr. Falkenberg clouds the issue when he argues that the mean can be more accurately calculated. The question of accurate calculation is not relevant. Either metric can be calculated accurately. The question is whether the mean or the median defines the central tendency of the VISTA hydro generation data distribution. In the case of a symmetric distribution the mean and the median would be equal. However, as Mr. Falkenberg correctly points out, the distribution of hydrologic generation data is asymmetric. Thus, it would be inappropriate to use the mean rather than the median to define the central tendency of hydro generation data. Again, the issue is not a question of accuracy, but a choice of the best statistic to use to define the central tendency.

The Company believes that the median rather than the arithmetic mean provides the best predictive result for any future year. All values above the median have the same probability of occurrence (50 percent) as do all of the values below the median. In a small sample, such as 40 measures of the annual hydro generation, the mean can be affected by the magnitude of a single extreme event.

As an example, consider the Lewis River historical generation. Exhibit 206 shows the mean and the median value of the historical generation calculated with and without the extreme years (above and below the 90th percentile). The effect of excluding the extreme years on the mean hydro generation is a shift of 190.6 megawatt ~~hour~~days, while the impact on the median is unaffected. By selecting the median rather than the arithmetic mean as the third point and measure of central tendency, there is some assurance of stability in the hydro generation distribution, with changes generally affecting the upper and lower bounds.

Q. Is Mr. Falkenberg's mean hydro adjustment calculation incorrect?

A. Yes. First, Mr Falkenberg substitutes the "mean" hydro generation impact in the calculation using a flawed linear regression approach. Second, he inappropriately averages the generation of three exceedence levels to determine the "mean" annual hydro generation.

As I explain, the 25 percent and 75 percent exceedence values have equal probability but not equal weight. Using them in a calculation of the mean is not appropriate. One would have to go back and model all the levels of generation to determine the average. However, the mean hydro impact calculation used by Mr. Falkenberg is wrong.

Q. What is Mr. Falkenberg's method for making the hydro adjustment, and why is it wrong?

A. Mr. Falkenberg uses a linear regression using the GRID hydro generation as the independent variable and the GRID model output of total Company net power costs as the dependent variable. In turn, he isolates the slope parameter, ignoring the intercept parameter, to calculate the difference between the Company's hydro normalized net power costs and an estimated mean hydro condition net power costs.

By ignoring the regression calculated intercept and substituting median hydro net power costs, Mr. Falkenberg produces a solution that is not feasible given his own regression estimates. The problem has two parts. First, rather than using the regression estimated intercept corresponding to his estimated slope parameter, he instead uses the median hydro net power costs as the intercept. Alone, this misstep causes his use of the regression approach to be misapplied. Second, though he estimates the slope parameter based on the total company hydro generation levels, his extrapolation uses differences. A regression estimate of the slope based on differenced data will produce a different slope than the one produced with Mr. Falkenberg's analysis.

Q. What is your recommendation?

A. Mr. Falkenberg's adjustment should be rejected because the median is the best measure of central tendency. Further, if Mr. Falkenberg's calculation is corrected to include all the information from his own analysis, the impact of his adjustment is zero.

ICNU Adjustment - 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 that the adjustment is trivial, not well supported and is not industry standard. The proposed adjustment would reduce proposed net power costs by $3.28 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 is not a sound reason for rejecting the adjustment. The fact remains that the Company's modeling of loads and resources does not capture station service when a unit is offline and station service is a load on the Company's system.

Q. How does the Company model the load associated with station service when thermal units are offline?

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 costs of that station service will not be recovered by the Company and there will not be a proper match between costs and benefits.

Q. Does Mr. Falkenberg's suggestion that his adjustment is reasonable because there are times when the Company's generation exceeds the maximum ratings modeled in GRID provide a supportive reason for adopting his adjustment?

A. No. The reasoning is not consistent with normalized ratemaking. As explained by Mr. Falkenberg, the higher operating levels are due to factors such as cooler operating temperatures, higher fuel quality and other circumstances, which allow generators to briefly exceed their rated capacities. This limited variation in generation does not belong in normalized ratemaking.

Q. Is the Company's adjustment one-sided as claimed by Mr. Falkenberg?

A. No. The Company's GRID modeling produces ~~44.9~~45.1 million megawatt hours of coal generation, which exceeds the actual 48-month period ended December 2006 amount of 44.6 million megawatt hours. Therefore, the Company's generation modeling is generous if anything.

Q. Do you agree with Mr. Falkenberg's claim that the Company's adjustment is trivial?

A. No. This is a substantial cost incurred to serve customers that should be recoverable.

Q. What is your recommendation for Mr. Falkenberg's adjustment?

A. The proposed adjustment should be rejected because the Company's adjustment is not one-sided, is not trivial and our modeling is appropriate.

ICNU Adjustment - 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.

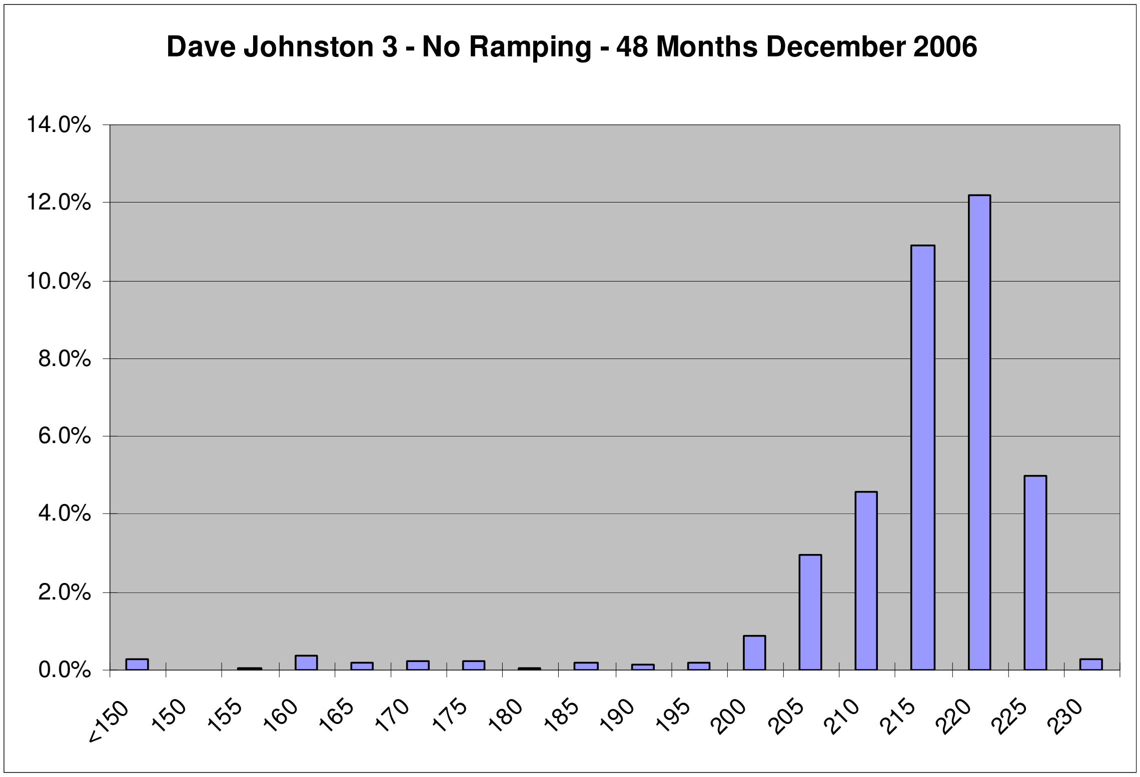
A. The proposed adjustment would increase the Company's official re-rated net generation capability of 220 megawatts to 230 megawatts. Mr. Falkenberg believes the adjustment is appropriate because at times the unit runs above the 220-megawatt level. The adjustment would reduce proposed net power costs by $2.71 million total Company.

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

A. No. The unit is limited by state law to 1.2 lb/MM Btu of SO2 emission as long as the heat input is below 2500 MMBtu/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/hour heat input, the unit produces approximately 220 megawatts 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 four years, the level of generation at the Dave Johnston 3 unit has exceeded the 220 megawatt level approximately 5900 hours and by nearly 1800 hours in 2006. Did the Company exceed the state imposed emission limit in these hours?

A. No. The Company reviewed the 48-month historical generation levels ending December 2006, 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 megawatts, on average, approximately ~~3.9~~5.0 percent of the time, as shown on Table 1 below. During these hours, the level of generation was on average 225 megawatts or less. 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 megawatt a limited amount of time but not consistently.


Dave Johnston 3 - No Ramping - 48 Months December 2006
14.0%
12.0%
10.0%
8.0%
6.0%
4.0%
2.0%
0.0%
<150
150
155
160
165
170
175
180
185
190
195
200
205
210
215
220
225
230

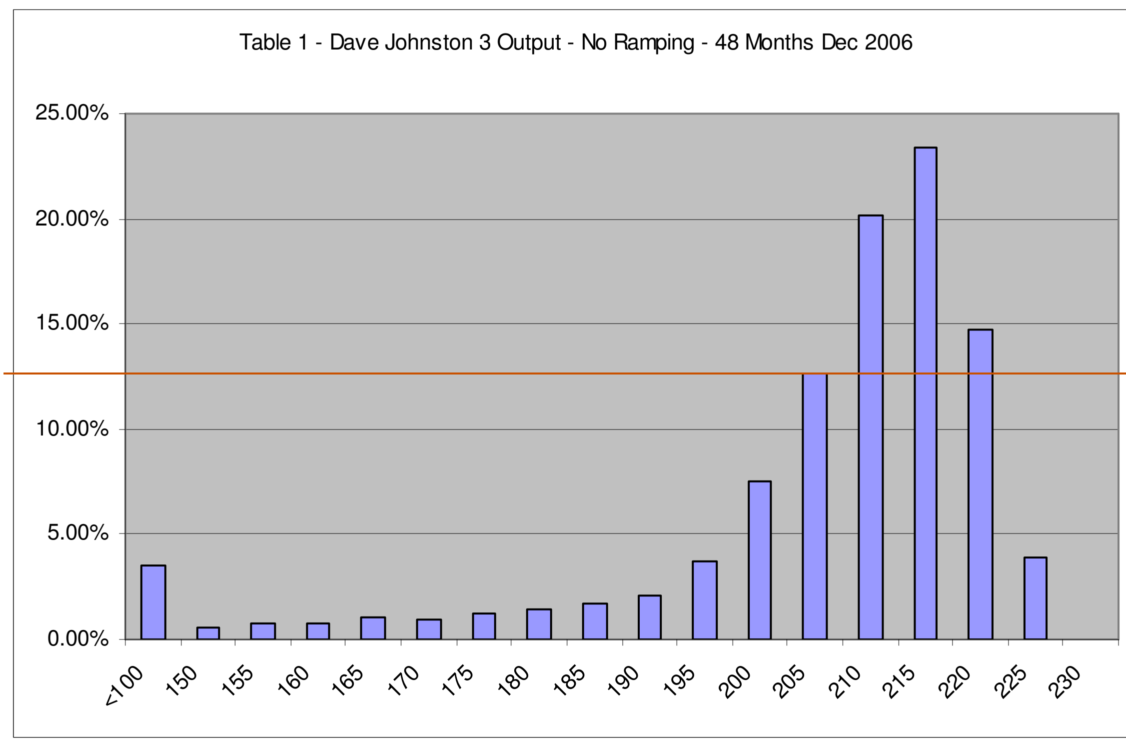


Table 1 - Dave Johnston 3 Output - No Ramping - 48 Months Dec 2006
25.00%
20.00%
15.00%
10.00%
5.00%
0.00%
<100
150
155
160
165
170
175
180
185
190
195
200
205
210
215
220
225
230

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 megawatts. In doing so, GRID would calculate the Equivalent Availability of this unit above 220 megawatts 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 megawatt 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.

ICNU 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 megawatt level to 150 megawatt. Mr. Falkenberg believes this is appropriate because the sodium depletion problem clears up during outages and the minimum can be reset to the 150 megawatt level. The adjustment would reduce proposed net power costs by $0.27 million total Company.

Q. Is this the first case that the Company has modeled Cholla 4 with a 250 megawatt minimum operating capacity?

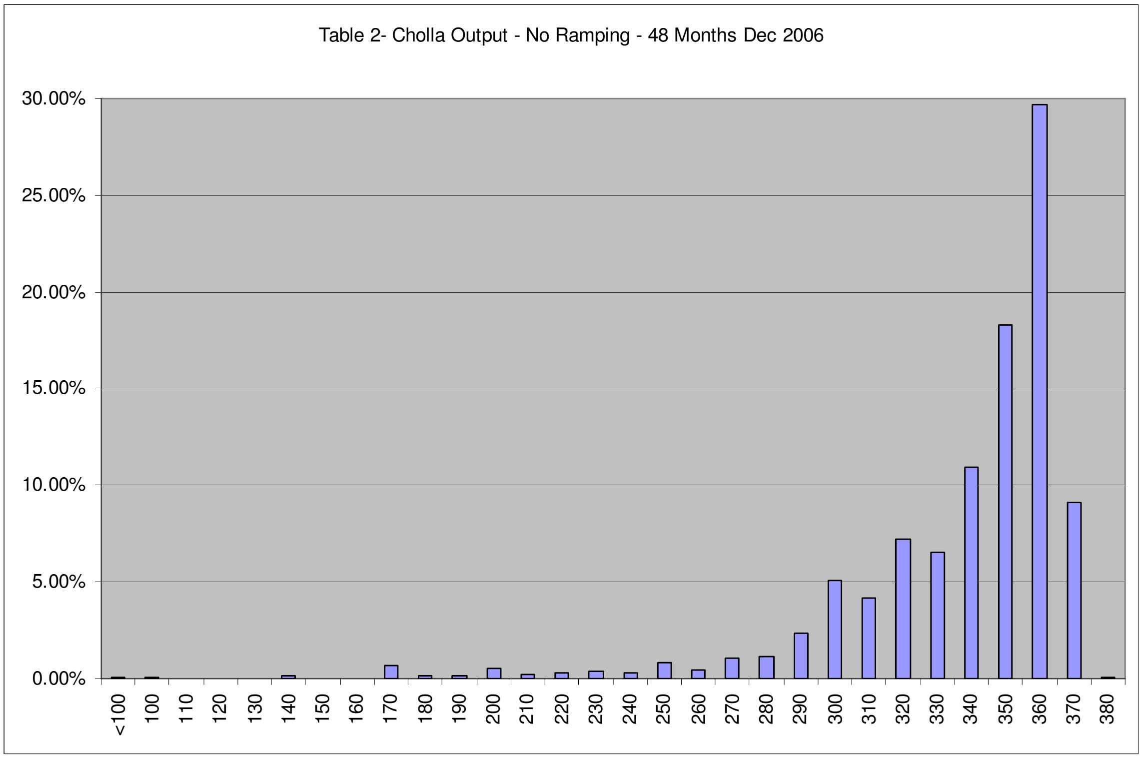
A. No. Contrary to Mr. Falkenberg's assertion, this is not the first case that the Cholla 4 minimum operating capacity has been modeled at 250 megawatts. The Company has been modeling Cholla 4 in this manner for several years.

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

A. The plants physical minimum operating level is 95 megawatts. Due to transmission constraints the Company is limited to a minimum generation level of 150 megawatts. Additionally, a sodium depletion problem causes the minimum loading of the plant to increase up to 250 megawatts in a period of 60 days after an outage. After an outage the sodium depletion issue clears up. The question here is the appropriate minimum operating level.

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

A. Yes, however, since Mr. Falkenberg focuses on how often the unit operates **below** 250 megawatts, 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 megawatts level only 3.0 percent of the time over the four years ending December 2006 as shown on Table 2 below. Obviously, the Company's modeling has not assumed a worst case scenario. By re-running GRID with the minimum operating level of Cholla 4 at 150 megawatts, the operating level falls below 250 megawatts approximately 14 percent of the hours. This is inconsistent with the historical results. Therefore, Mr. Falkenberg's proposed adjustment should be rejected.



ICNU Adjustment - Planned Outages, Currant Creek

Q. Earlier in your testimony you indicated that you accepted the Gadsby CTs portion of Mr. Falkenberg's proposed adjustment but did not accept the Currant Creek portion of the adjustment. Please explain your reasoning

A. The reasoning is straightforward. The Company has fours years of actual information for the Gadsby CTs so it is appropriate to use a 48-month average. On the other hand, Currant Creek is a new plant and does not have 48 months of history to create the normalized maintenance level. It has been the Company's policy that when a new generating unit comes online, the planned maintenance schedules will be estimated based on manufacturers' recommendations. For the type of units used at the Currant Creek plant, the manufacturer GE Energy has recommended schedules for various maintenances. For example, combustion inspections will take seven days; hot gas path inspections will take 14 days; and major inspections will take 28 days. Based on this information, the Company made a very conservative estimate and modeled the seven-day maintenance schedule for Currant Creek. Therefore, Mr. Falkenberg's proposed adjustment to the maintenance schedule of the Currant Creek plant should be rejected.

CUB Adjustment - GRID Version Change

Q. Please explain the background on the Company's proposal to use an upgraded version of GRID in this case.

A. Prior to beginning the preparation of the 2008 TAM filing, the Company approached Staff, CUB and ICNU about the possibility of using the latest version of GRID, version 6.1, instead of version 5.3, which was used in the prior general rate case. In these conversations, we informed the parties that the Company believed that the upgraded version 6.1 would produce a slightly lower net power costs than version 5.3. Staff consented to use of the GRID update, and ICNU indicated they would not contest the update. In my conversion with Mr. Jenks, I understood that CUB would also not contest the update.

Based upon these conversations, the Company developed the TAM filing based on version 6.1. Subsequently, during a discussion with CUB immediately before this case was filed, CUB informed the Company that it did not agree to the use of version 6.1. Unfortunately, the case had been substantially prepared and the Company was unable to go back to version 5.3 and meet the required April 2, 2007 filing date.

Q. Would switching back to GRID version 5.3 be a burden at this point?

A. Yes. Switching back to version 5.3 would be an administrative burden at this point as it would require the parties to return their GRID computers to the Company so they could be re-imaged with version 5.3. This could not occur until after the two-to-three week period necessary for the Company to convert the net power costs data into version 5.3 format. Going backwards to version 5.3 would also require the parties to rerun analysis already performed with version 6.1.

Q. Does this conclude your rebuttal testimony?

A. Yes.