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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF ROCKY MOUNTAIN POWER FOR APPROVAL OF CHANGES TO ITS ELECTRIC SERVICE SCHEDULES AND A PRICE INCREASE OF $27.7 MILLION OR APPROXIMATELY 13.7 PERCENT	)))))))	**CASE NO. PAC-E-10-07** **Direct Testimony of Randall J. Falkenberg**

DIRECT TESTIMONY OF RANDALL J. FALKENBERG

ON BEHALF OF

THE PACIFICORP IDAHO INDUSTRIAL COMSUMERS

REDACTED VERSION

October 14, 2010

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Randall J. Falkenberg, PMB 362, 8343 Roswell Road, Sandy Springs, GA 30350.

Q. BY WHOM ARE YOU EMPLOYED?

A. I am President of RFI Consulting, Inc. ("RFI"). I am appearing in this proceeding as a witness for the PacifiCorp Idaho Industrial Customers ("PIIC"). My qualifications are in Exhibit No. 605. I have been involved in PacifiCorp (or "the Company") power cost related cases for more than ten years in California, Oregon, Utah, Washington and Wyoming.

Q. WHAT KIND OF CONSULTING SERVICES ARE PROVIDED BY RFI?

A. RFI provides consulting services in the electric utility industry. The firm provides expertise in system planning, financial analysis, cost of service, revenue requirements, rate design, and energy cost recovery issues.

I. INTRODUCTION AND SUMMARY

Q. WHAT IS THE PURPOSE OF THIS TESTIMONY?

A. My testimony addresses PacifiCorp's GRID study of normalized net power costs ("NPC") for the December 31, 2010 test period. I identify certain problems in the GRID model that overstate PacifiCorp's proposed Idaho revenue requirements. I also address a related issue concerning combined cycle plant Operations & Maintenance ("O&M"). Because Idaho uses a true-up mechanism for PacifiCorp, I am not presenting a complete analysis of NPC modeling issues. Instead, I am concentrating more effort on issues that also have an implication for the Energy Cost Adjustment Mechanism true-up, or revenue requirements not subject to the true-up. I am discussing some important modeling issues as it is important to set the NPC baseline as accurately as possible.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. I have identified and quantified certain adjustments to the Company's GRID model study. These adjustments are shown on Table 1 and are summarized below. All adjustments are addressed in more detail later in this testimony. Following Table 1 is a summary explaining the basis for all proposed adjustments and other recommendations.

Conclusions and Recommendations

PacifiCorp's requested 2010 NPC of $1,070 million (total Company) in NPC is overstated by at least $25 million. My corrections result in a reduction to Idaho jurisdictional NPC of $1.51 million. I also recommend additional reductions of $29 thousand to the Idaho allocation revenue requirements related to reductions to combined cycle plant O&M. As I explained earlier, I have not done a complete analysis of the Company's NPC in this case, and additional reductions to the Company's NPCs may well be warranted.

Table 1
Summary of Recommended Adjustments

	Total Company		Est. ID Jurisdiction
		SE	6.36%
		SG	5.51%
I. GRID (Net Variable Power Cost Issues)			
PacifiCorp Request NPC	1,069,701,315		69,200,000
A. GRID Commitment Logic Error and Start Up Costs			
1 Commitment Logic Screens[1/]	(588,429)		(34,912)
2 Start Up Energy [2/]	(1,676,474)		(99,465)
B. Long Term Contract Modling			
3 SMUD Contract Delivery Pattern	(1,566,786)		(92,957)
C. OATT Wind Integration Costs			
4 Non-Owned Inter Hour Wind	(2,041,963)		(121,150)
5 Non-Owned Intra Hour Wind	(4,320,031)		(256,307)
D. Outage Modeling and Other NPC Adjustments			
6 Lake Side Outage	(2,163,834)		(128,380)
7 Colstrip Outage	(1,300,710)		(77,171)
8 JBFuel Adjustments	(2,460,037)		(145,954)
9 Naughton Outage	(700,273)		(41,547)
10 Heat Rate Adjustment	(1,831,473)		(108,661)
E. Transmission Issues			
11 DC Intertie Costs	(4,766,400)		(282,791)
12 Populus to Ben Lomond Line Losses	(1,146,067)		(67,996)
13 Idaho Power PTP Contract	(842,386)		(49,979)
Subtotal NPC Baseline Adjustments -	(25,404,863)		(1,507,271)
Allowed - Final GRID Result*	1,044,296,452		67,692,729
G. Other Adjustments			
14 Combined Cycle O&M Adjustment	(490,000)		(29,072)
Total Adjustments	(25,894,863)		(1,536,342)
Notes			
[1/] Adjustment incresed if Adjustment 14 is not approved. In that case Adj. 1:	(1,259,760)		(74,742)
[2/] Adjustment assumes Co. Screens. Adjustment if ICNU screens adopted:	(1,393,200)		(82,659)

A. <u>GRID Commitment Logic Error and Start Up Costs</u>

<u>Adjustment 1.</u> The Company acknowledges that GRID contains a logic error that results in incorrect start up and shut down decisions for gas-fired resources. This error produces an upward bias on NPC. The Company attempts to correct this error with a "screening" methodology. However, the Company's correction is ineffective. I illustrate a more effective solution to this problem as applied to the Currant Creek unit.

<u>Adjustment 2.</u> The Company includes the cost of fuel used to start up gas plants, but ignores energy generated in the

process. I recommend reflecting the value of start-up energy in the test year.

B. <u>Long Term Contract Modeling</u>

<u>Adjustment 3.</u> The Company incorrectly models the Sacramento Municipal Utility District ("SMUD") sales contract by assuming the counterparty will take power only during the highest cost months. Actual contract delivery data shows the contract should be modeled to reflect a lower cost delivery pattern.

C. <u>OATT Wind Integration Adjustments</u>

<u>Adjustments 4-5.</u> The Company includes various costs related to integration of non-owned wind resources. These costs should be excluded because the Company is not compensated for providing these integration services. The Company has already acknowledged that it does not need to provide inter-hour wind integration services for non-owned wind farms. The Commission should also make comparable adjustments in true-up proceedings.

D. <u>Outage Rate Adjustments</u>

<u>Adjustments 6-7.</u> These adjustments cap exceptionally long outages at Lake Side and Colstrip 4 at 28 days in the four-year average outage rate calculation. It is unrealistic to assume such an extreme event will occur once every four years.

<u>Adjustment 8.</u> This adjustment addresses the high cost and low quality of the Bridger fuel supply. Fuel quality problems result in inordinately high levels of lost production as compared to other plants.

<u>Adjustment 9.</u> The Company includes an outage at the Naughton plant that was due to the negligence of a subcontractor. The costs of such events should be assigned to the Company rather than customers.

<u>Adjustment 10.</u> GRID biases average heat rates due to its modeling of forced outage rates as capacity derations. When GRID models a unit at its derated maximum

capacity, the heat rate normally exceeds the full loading average heat rate. This adjustment corrects this problem.

E. Transmission Issues

Adjustment 11. **It appears the Company includes no transactions that utilize the DC Intertie in the test year. I recommend removal of intertie costs to match costs and benefits in the test year. I further recommend the Company be required to demonstrate the prudence of its management of this contract.**

Adjustment 12. **I don't take any position on including the Populus to Ben Lomond transmission line in the test year. However, if included, I recommend an adjustment to reflect reductions in losses the line will produce.**

Adjustment 13. **The Company includes an expiring transmission contract that will no longer be needed after completion of the Populus to Ben Lomond line. If the new line is included in the test year, transmission wheeling expense should be reduced to remove the cost of this contract.**

F. Non Fuel Start up O&M

Adjustment 14. **My proposed screening adjustment reduces the number of starts of combined cycle plants in the test year, overstating O&M costs. If this adjustment is not adopted, a higher value for Adjustment 1 should be used as is shown in Table 1.**

G. Filing Requirements

I recommend the Company be required to file specific GRID workpapers in future cases. The Company has agreed to these requirements in other states. It should not be difficult for the Company to comply with this requirement.

GRID COMMITMENT LOGIC ERROR

Adjustment 1: Commitment Logic Screens

Q. PLEASE PROVIDE SOME BACKGROUND CONCERNING THIS ISSUE.

A. GRID has a logic error that results in improper unit commitment and dispatch decisions for gas units and call options. The Company acknowledges the problem exists in GRID. This problem has existed since the model was developed, and has been acknowledged by the Company in numerous recent cases in the various states.

Absent user-supplied workarounds, GRID frequently fails to develop the least cost sequence of start-ups and shut-downs of gas-fired resources. Left alone, there are many hours when gas-fired generators fail to operate economically within the model. This has a spillover effect on coal-fired generation because the uneconomic operation of gas plants forces lower cost coal units to have their output curtailed.

The problem occurs because the logic in GRID separates the decision to commit (start up or to not shut down) a resource from the operating constraints (transmission and market capacity limits) imposed by other model inputs. However, these operating constraints are used later to determine the optimal dispatch of resources. The model unrealistically assumes there is always a market for energy when making the commitment (start up or shut down) decision, but once the units are running GRID assumes there is no market for the energy these resources could otherwise sell due to the previously ignored constraints.

Q. EXPLAIN YOUR INVOLVMENT IN THIS ISSUE.

A. I have addressed this issue in testimony in several states. I first brought it to the Company's attention in Wyoming Public Service Commission docket No. 20000-277-ER-07 in January 2008. Since that time both the Company and I have addressed various solutions in cases in Oregon, Washington, Wyoming and Utah. The Utah Public Service Commission ("Utah Commission") adopted my proposed adjustments related to this issue in Docket Nos. 07-035-89[1] and 09-035-23.[2] All of the other cases where this matter was at issue resulted in settlements that did not adopt any specific adjustment related to this problem.

Q. HAS THE COMPANY ATTEMPTED TO ADDRESS THIS PROBLEM IN ITS FILING?

A. Yes. Dr. Shu has included a daily "screening adjustment," which is intended to correct this problem. In the response to Monsanto Data Request ("DR") 2.8, the Company provided the workpapers used to develop the screens. Essentially, this methodology forces a specific daily schedule or screen for gas plants if it can reduce NPC relative to the GRID model's internal logic. Otherwise, the Company allows GRID to develop its own schedule, using the

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[1] Re Rocky Mountain Power 2007 General Rate Case, Utah Commission Docket No. 07-035-93, Report and Order on Revenue Requirements at 30 (August 11, 2008).

[2] Re Rocky Mountain Power 2009 General Rate Case, Utah Commission Docket No. 09-035-23, Report and Order on Revenue Requirements, Cost of Service and Spread of Rates at 29 (Feb. 18, 2010).

flawed logic. The Company's method is an improvement over its prior efforts. However, it can and should be improved upon to eliminate as much of the error induced cost as possible.

Q. IS THE COMPANY'S NEW SOLUTION ONE THAT YOU HAVE PREVIOUSLY PROPOSED?

A. No. The Company's proposal was developed in response to my previous proposal to use daily screens; however, the Company's approach differs from my recommended solutions and from the solutions previously accepted by regulators.

Q. HOW CAN THE COMPANY'S SCREENS BE IMPROVED?

A. Two basic improvements are required. The Company should turn off the GRID commitment logic entirely. It has become apparent that the internal logic is more flawed than previously thought. In the past, it was assumed that the only problem in GRID was that it sometimes allowed plants to run when they should have been shut down. However, it is now apparent that at times, the logic may actually shut down plants when they should be allowed to run. Consequently, relying on the internal logic as the starting point fails to identify the optimal solution. However, solving this problem requires only that the cycling units be modeled on a must run basis in the preliminary run used to develop the screens.

Q. WHAT OTHER PROBLEMS EXIST IN THE COMPANY'S DAILY SCREENS?

A. The Company method examines only a limited number of possible daily screens or schedules. For example, the Company examines 18 possible screens for Currant Creek. This limits the number of start-up/shut down choices. For example, a 10 PM shutdown of 6, 7, or 8 hours is considered, but not a longer and more accurate shutdown period. Consequently, one problem is the inflexibility of the Company approach and its failure to examine more optimal schedules.

Q. ARE THERE OTHER PROBLEMS IN THE COMPANY'S ANALYSIS?

A. Yes. Another problem with the Company's methodology is that it may be using an erroneous assumption regarding start up O&M costs. The Company assumes that starting up of a combined cycle plant requires a specific amount of fuel be burned and that other, incremental non-fuel O&M expenses will be incurred as well. In principle, I agree on both counts. However, the Company fails to recognize the energy produced during the start up sequence in its test year, and it appears that the Company may not be accounting for the incremental effect of these non-fuel O&M expenses in the preparation of its test year. If so, then both problems need to be addressed.

Q. DESCRIBE THE METHODOLOGY YOU PROPOSE.

A. The proposed methodology is similar, but more flexible. First, the GRID internal logic is turned off by invoking the must run status for each cycling unit screened. Consequently, when the screening method is applied, it determines each hour of the year when cycling units should be running or not. The Company recently agreed to make this change along with other improvements to its screening method in OPUC Docket No. UE 216.[3/] Rather than limiting the analysis to 18 screens per day, it examines 168 daily screens, and considers the possibility of a start-up or shut down every hour of the day.[4/] The method also will allow a single screen to run for days or even weeks in succession if that is the optimal choice.

Q. EXPLAIN THE ADJUSTMENTS YOU COMPUTED IN TABLE 1.

A. In Table 1, I estimate the effect of implementing more optimal screens for the Currant Creek plant. Because my screens result in a much smaller number of start-ups than the Company screens, there is also change in the amount of incremental start-up fuel and fixed (non-variable NPC) O&M expenses included in the test year. I have identified the start up O&M component of cost on Table 1, as Adjustment 14, while the fuel and purchased power cost impacts are included in Adjustments 1 and 2.

Q. HAS THE COMPANY APPLIED ITS SCREENING METHOD TO ALL RESOURCES SUBJECT TO THE LOGIC ERROR?

A. No. The Company did not apply its correction to the duct firing capability of Currant Creek or Lake Side, nor to call options. In the case of Lake Side this is a substantial problem, as the capability is invoked many hours (1048) when it is uneconomic to run. Considering the resource is only economic to run for

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3/ Re PacifiCorp's 2011 Transition Adjustment Mechanism, OPUC Docket No. UE 216, Stipulation at 3-4 (July 7, 2010).

4/ It is not difficult to expand the number of screens further and I would not object to doing so.

1683 hours, this means GRID produces an incorrect dispatch 38% of the time. In fact, there are four entire months when it would be less costly if the GRID model never used the Lake Side duct firing. I have also corrected this problem in Table 1. The Commission should require the Company to address this problem as well.

Q. WHY DON'T YOU DEVELOP SCREENS FOR ALL OF THE PACIFICORP GAS-FIRED PLANTS?

A. The final screens will depend on the adjustments adopted by the Commission and any other updates or corrections. My purpose in this case is to explain and illustrate the correct way to develop the screens, and recommend the Commission require this approach in its final order. I recommend the Commission require the Company to implement my proposed screening method after the Company models all Commission approved adjustments as a "final" GRID run for this case.

Adjustment 2: Start Up Energy

Q. DR. SHU TESTIFIES ON PAGE 8 THAT SHE INCLUDED START UP GAS COSTS IN GRID. DO YOU AGREE WITH INCLUSION OF START-UP GAS COSTS IN NPC?

A. Yes, these are legitimate net power costs. However, the Company only considers the cost of fuel required to take the unit from a warm shut-down state to minimum load but ignores the energy produced during this process. During the period the units are ramping up (about 2 hours), the power output of these units is gradually increasing.

Q. HAS THE COMPANY OPPOSED THIS ADJUSTMENT IN OTHER STATES?

A. Yes. The Company has argued various points including: 1) Within an hour there is no market for the energy; and 2) Start-up energy imposes additional reserve requirements on the system.[5/] Based on these kinds of qualitative arguments, the Company argues no value should be ascribed to start-up energy.

Q. DO YOU AGREE WITH THESE CRITICISMS?

A. No. Were the Company to apply the same arguments to wind energy, it would suggest that wind energy has zero value, or worse – that integration costs actually exceed the dispatch benefits of wind resources. All of these concerns apply more directly to wind energy than to start-up energy. For example, start-up energy is far more predictable on a day ahead, hour ahead, and intra-hour basis than is wind energy. While dispatchers do not know if wind will blow the next day or the next hour, suddenly quit, or ramp up unexpectedly, this is not the case for combined cycle plant start-up energy. Gas plant schedules are a *plan* made a day in advance, while a "wind schedule" is merely a *weather forecast*. One can predict combined cycle start energy far more reliably than wind power. The arguments concerning the lack of an intra-hour market apply to wind energy even more-so than start-up energy.

[5/] See Utah Commission Docket No. 09-035-23, Rebuttal Testimony of Gregory N. Duvall at 15-16 (Nov. 14, 2009). Mr. Duvall also made an argument concerning minimum down times which I have addressed in my analysis in this case.

Q. DID YOU ALSO CONSIDER THE CONCERNS REGARDING THE NEED TO INCREASE RESERVES TO COVER THE RAMP UP OF THE COMBINED CYCLE PLANTS IN YOUR ANALYSIS?

A. Yes. The approach I have taken is to conservatively assume that start up energy results in a back-down of coal generation which is then used for load following and providing reserves. This provides a floor on the value of start-up energy, which should be reflected in the test year.

Q. HAVE OTHER EXPERTS SUPPORTED THIS TYPE OF POWER COST ADJUSTMENT?

A. Yes. In the 2009 Utah General Rate Case (Utah Commission Docket No. 09-035-23), the Utah Division of Public Utilities power cost expert, Mr. George Evans, proposed a similar adjustment. Mr. Evans also testified in response to one of the Commissioner's questions that modeling of start-up energy was the industry standard approach.[6/] Mr. Evans has testified in numerous cases throughout the US and has approximately 30 years experience in power cost modeling.

<u>Adjustment 14: Start Up O&M</u>

Q. EXPLAIN WHAT IS MEANT BY START UP O&M.

A. The Company assumes that starting up a gas combined cycle plant will result in incremental non-fuel O&M expenses. The logic used in its screening method considers this cost before allowing these units to restart after a shutdown. I agree with this, in principle, and have included the same kinds of

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6/ <u>Re 2009 Utah General Rate Case</u>, Utah Commission Docket No. 09-035-23, Transcript at 549 (Dec. 14, 2009).

costs in my screening method. Because my proposed screens are more efficient, they result in 95 fewer start ups for Currant Creek than the Company screens allow. This implies lower non-fuel O&M costs should result for the unit. The Company's screening method actually *increases* the number of starts relative to the case with no screens, suggesting an increase to non-fuel O&M would is warranted if one accepts Dr. Shu's screens. Consequently, Adjustment 14 provides my calculation of the benefits of the reduced non-fuel O&M expense for the Currant Creek plant. When coupled with the Company's generation overhaul cost for Current Creek (see McDougal Exhibit No. 2 at 4.10.1), it would lower the Currant Creek overhaul costs to a level closer to that of Lake Side and Chehalis for the test year. Consequently, I recommend this adjustment to the test year as well.

Q. DOES THE COMPANY ACTUALLY INCLUDE ANY ADJUSTMENT TO THE TEST YEAR TO ACCOUNT FOR THE CHANGE IN START UP O&M DUE TO ITS SCREENS?

A. It appears they may not be doing so. I don't see any adjustment to account for the start up O&M in either the Net Power Cost adjustments or the Generation Overhaul expense adjustments. If so, then it may not be appropriate to make the reduction to non-fuel O&M recommended in Adjustment 14. However, if that's the case, then the assumption the Company uses in setting its screens (which includes a non-fuel start up O&M cost of [redacted] per start) is most certainly wrong, and should be eliminated. Either the cost is real (and should be included in the test year) or its not (and should not be used in computing the screens). Only one of these choices can be correct. If it's the former, the Adjustment 14 is appropriate. If it's the later, then a different screen is optimal and the reduction to NPC in Adjustment 1 would be substantially greater as shown on the footnote to Table 1. This is because the lower start up costs result in more economic starts, and a bigger impact from the use of a proper screen as compared to the Company runs. In either case the test year revenue requirements are lower than proposed by the Company.

B. LONG TERM CONTRACT ADJUSTMENTS

Q. DOES GRID MODEL PURCHASE AND SALES CONTRACTS?

A. Yes. GRID includes the costs and energy produced by its long-term and short-term contracts, along with its thermal generation resources.

Adjustment 3: SMUD Contract Delivery Pattern

Q. WHAT IS A CALL OPTION CONTRACT?

A. This is a contract that allows the purchaser the right to pre-schedule energy deliveries based on expected market prices and/or the purchaser's requirements. The Company is both a buyer and seller of call option contracts. The Company models a "call option sale" contract for the SMUD in the GRID model.

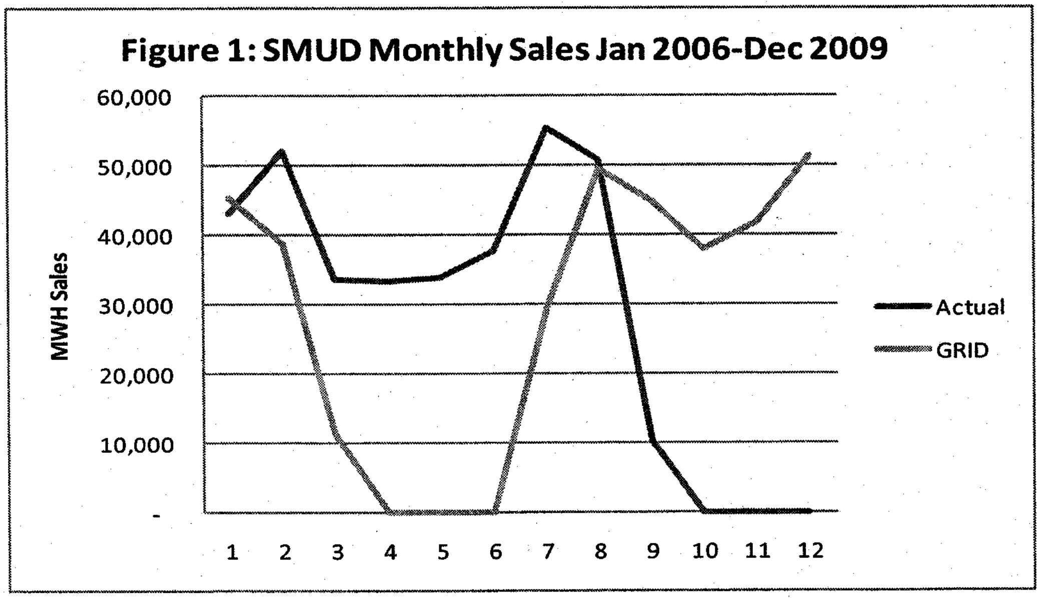
Q. EXPLAIN THE MODELING OF CALL OPTION SALES IN GRID.

A. In GRID, inputs specify contractual energy limits on an hourly, daily, weekly, monthly or annual basis. For sales with annual contract energy limits, such as the SMUD contract, GRID schedules the contract energy during the highest cost hours of the year. Because the contract has an annual energy limit of approximately 350,400 MWh (with a 100 MW maximum hourly take), the Company assumes SMUD will call the energy from the contract during the highest cost[7/] 3504 hours[8/] in the year. For SMUD, GRID assumes the counterparty finds the <u>most costly way possible</u> to use the energy available under the contract. In effect, the Company's modeling assumes the "worst case" scenario.

Q. IS THIS REALISTIC?

A. No. In fact, it simply does not happen in actual operation. Figure 1, below, compares the actual monthly delivery patterns of the SMUD contract to the GRID assumptions. Generally, SMUD use this resource in a manner that is far less costly than assumed by the Company. While the Company assumes SMUD will never take power during low cost months such as April through June, in reality SMUD takes substantial deliveries during those months.

7/ Based on COB market prices.
8/ 350,400/100= 3504.



There are many reasons why this is be the case. First, SMUD is not using the same forward price curves as the Company. It is safe to assume that SMUD has no specific knowledge of the Company's forward price curves or vice-versa. Differences in delivery location, transmission constraints, availability of the SMUD's own generation and many other factors will drive decisions to use the available energy. In the end, SMUD is interested in serving its own customers at the least possible cost (subject to its own constraints), not in maximizing the cost to PacifiCorp. The Company's approach does not represent "normalization" of the contract, but rather the very worst possible outcome for the Company.

Q. DOES THE COMPANY USE HISTORICAL DATA IN THE MODELING OF OTHER CONTRACTS?

A. Yes. The Company uses historical data to compute various inputs for the various contracts including APS, Black Hills Power, GP Camas, small purchase contracts, and reserve requirement inputs for non-owned generation located in its service area. Further the market caps used in GRID are based on historical data as well. Use of historical data is common in the Company's modeling of contracts.

Q. IN UTAH COMMISSION DOCKET NO. 07-035-93, YOU PROPOSED THE SAME NORMALIZATION ADJUSTMENT FOR THE SMUD CONTRACT. WHAT WAS THE OUTCOME OF THAT CASE?

A. The Utah Commission accepted the adjustment.[9/] The Utah Commission also declined to act on the Company's request for reconsideration regarding the matter. Finally, in Docket 09-035-23, the Utah Commission reaffirmed its support of this adjustment.[10/] As in the case of the screens, this issue has not been resolved in other states. Despite all this, the Company still disagrees with the adjustment and does not apply it in any other state. The Company has made a number of different arguments regarding this issue. In other testimony, the Company suggested that if it were correct to not use the actual data in determining the dispatch of call option sales contracts, one should assume the Company would not make the least cost decisions concerning its own purchase agreements such as the Hermiston purchase or the Bonneville Power Administration ("BPA") contract.

9/ Re Rocky Mountain Power 2007 General Rate Case, Utah Commission Docket No. 07-035-93, Report and Order on Revenue Requirements at 23 (August 11, 2008).

10/ Re Rocky Mountain Power 2009 General Rate Case, Utah Commission Docket No. 09-035-23, Report and Order on Revenue Requirements, Cost of Service and Spread of Rates at 36 (Feb. 18, 2010).

Q. DO YOU AGREE WITH THESE ARGUMENTS?

A. No. Based on such reasoning, one would not depart from the "highest cost" modeling of SMUD unless one abandoned the least cost modeling of Hermiston, BPA or other resources. Such arguments miss the fundamental point of this analysis and of power cost modeling in general. The Company decides when to use, or not use the BPA and Hermiston purchases and does so to minimize costs, subject to the constraints the Company is facing. In the case of SMUD, the Company <u>simply does not know and has not modeled any of the loads, constraints or forward prices curves used by SMUD</u>. Were the Company able to do so, it might make sense to model them in GRID without any adjustments derived from historical data. In effect, GRID is "flying blind" when it comes to the counterparties and has no reasonable basis for assuming the counterparties can even use the power available at all the highest cost hours. History shows they simply do not do so. In the end, the adjustments I make to the SMUD delivery pattern are simply a proxy for the constraints and other assumptions related to the SMUD contract that are unknown and probably unknowable to PacifiCorp. I recommend that Commission adopt Adjustment 3, to implement a more realistic shape for the SMUD contract.

C. NON -OWNED ("OATT") WIND INTEGRATION COSTS

Q. DOES THE COMPANY INCLUDE WIND INTEGRATION COSTS FOR ANY NON-OWNED WIND FARMS LOCATED IN ITS SERVICE AREA?

A. Yes. The projects are generally transmission customers taking service under the terms and conditions of the Company's Open Access Transmission Tariff ("OATT").

Q. DOES PACIFICORP'S OATT INCLUDE ANY CHARGES FOR WIND INTEGRATION SERVICES?

A. No. While the OATT does provide for charges for reserves for transmission customers, it does not provide any charges for wind integration service. As a result, the Company is providing integration services to these customers without compensation. Unfortunately, retail customers will be required to subsidize wholesale transmission service, if this is allowed by the Commission.

Q. DO OTHER TRANSMISSION PROVIDERS INCLUDE WIND INTEGRATION CHARGES IN THEIR OATT?

A. Yes. BPA includes such charges in its OATT, and PacifiCorp pays BPA for wind integration services. The Company has included these charges in its GRID test year for some time. There is no reason why the Company should not seek approval to include such charges in its OATT. Until such approval is granted, the Company should not be allowed to charge retail customers for providing services to its wholesale transmission customers.

Q. IS THERE ANY REASON WHY THE COMPANY COULD NOT HAVE ALREADY MADE A FILING AT THE FERC SO THAT IT COULD HAVE INCLUDED WIND INTEGRATION CHARGES IN ITS OATT, OR IMPLEMENT SOME OTHER MECHANISM?

A. No. The Company has expected since at least the time of its 2004 IRP that it would experience substantial costs for wind integration. Its 2004 IRP supported a value of $4.64/MWH.[11/] By January 1, 2011, the Company will have had more than six years to have made the appropriate filings with the FERC to recover wind integration costs from transmission customers. Further, the Company has conducted numerous meetings relative to its jurisdictional allocation procedures for the past decade. There is no reason why the Company should not have engaged the FERC in this process to address an equitable solution to the OATT wind integration issue. The Company's lack of diligence is no excuse to charge retail customers such costs.

Adjustment 4: Non-Owned Wind Farm Inter-Hour Integration Costs

Q. PLEASE EXPLAIN THE BASIS FOR THIS ADJUSTMENT.

A. The Company models a charge of $6.50/MWH for wind integration costs in GRID. This includes both intra and inter-hour integration costs for non-owned wind farms for which it provides transmission services. The Company did not differentiate between these two kinds of costs in this case, but has done so in its IRP studies.

Adjustment 4 removes the cost of inter-hour wind integration from GRD for non-owned generators. This is much the same as the case of the

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11/ Re PacifiCorp Large QF Avoided Cost Case, Utah Commission Docket No. 03-035-14, Report and Order at 23 (Oct. 31, 2005).

Goodnoe and Leaning Juniper projects which are located on the BPA transmission system. The Company assumes it must provide its own inter-hour integration for these wind farms, and that BPA will not do so. Likewise, it stands to reason that non-owned projects located on the PacifiCorp transmission system should not require or be provided inter-hour integration from PacifiCorp. The Company recently indicated in an Oregon discovery response that it agrees with this position.[12/] I estimated this adjustment by removing the Company's estimated 2010 inter-hour wind integration cost ($2.09/MWH) from the Company's assumed total wind integration cost used in this case ($6.50/MWH).

Adjustment 5: Non Owned Intra Hour Wind Farm Integration Costs

Q. PLEASE DISCUSS THIS ADJUSTMENT.

A. This adjustment completes the disallowance of the cost of integrating OATT customer wind farms by removing the intra-hour cost component. It is computed by taking the residual of the figures quoted above ($6.50-$2.09) times the OATT wind farm MWH.

Q. DOES THIS ADJUSTMENT HAVE AN IMPLICATION FOR THE TRUE-UP PROCEEDING?

A. Yes. The true up should make a parallel adjustment for OATT wind farms to eliminate the actual cost of providing integration services to these entities. If this is not done, retail customers will be charged for providing service to wholesale transmission customers.

12/ Exhibit No. 607 at 1 (Response to OPUC DR 22, OPUC Docket No. UE 216).

D. OUTAGE RATE MODELING ISSUES

Q. EXPLAIN THE USE OF THERMAL DERATION FACTORS IN GRID.

A. In GRID, thermal deration factors (also called unplanned outage rates) control the amount of generation available from thermal units. The more energy available, the lower net variable power costs. If a generator has an average unplanned outage rate of 20%, GRID assumes a thermal deration factor of 80%. This means that only 80% of the unit's capacity is available to produce energy. The remaining capacity is assumed to be permanently unavailable. The Company computes thermal deration factors based on a four year moving average of outage rates. This calculation includes all outage events that occurred during the four year period (2006-2009). This provides a mechanism for the Company to recover costs associated with prior outages, albeit at current market prices.

Q. ARE UNPLANNED OUTAGES AN IMPORTANT DRIVER IN OVERALL NET POWER COSTS?

A. Yes. Any increase in unplanned outages increases NPC. Consequently, it is important to review unplanned outages to determine if they were prudent or reasonable to included in a four year moving average.

<u>Adjustment 6-7: Lake Side and Colstrip 4 Extreme Outage Events</u>

Q. PLEASE EXPLAIN THIS ADJUSTMENT.

A. In reviewing Dr. Shu's workpapers, I noticed that Lake Side had an extremely high outage rate modeled in GRID. Based on the historical data period used by the Company, Lake Side had an outage rate of [redacted]. In examining the data supporting this figure, I found that more than [redacted] of the lost energy was due to a single event starting [redacted]

Q. PLEASE DISCUSS THE LONG OUTAGE AT COLSTRIP 4 IN 2009.

A. A problem was discovered during the 2009 planned outage of Colstrip 4, which prevented the units' return to service in May. The outage extended for [redacted] before the equipment could be repaired. This single event was responsible for [redacted] of the lost generation at the plant in the entire four year period. As a result, the Company computes an average outage rate for Colstrip 4 of [redacted]. For 2009 this equates to an outage rate in [redacted] for the unit.

Q. SHOULD THE ENTIRE DURATION OF THESE EVENTS BE REFLECTED IN RATES?

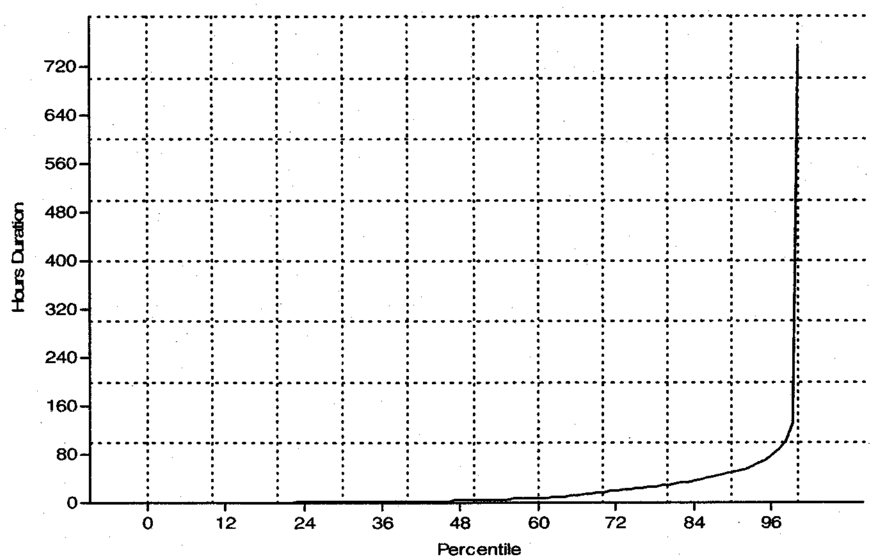
A. No. These were extremely rare events and not ones likely to recur once every four years, as is assumed in the Company's four year moving average calculation. It is very unlikely that these events are representative of conditions in the rate effective period. As a result, it is quite likely that including these events in the test year outage rate will produce an inaccurate forecast. Further, the extreme length of these events suggests a prudence investigation should be undertaken in the appropriate true up proceeding.

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend these outages be capped at 28 days in the outage rate calculation. This approach was recently recommended by a Company witness in a recent OPUC docket, UM 1355, and provides a reasonable method for dealing with extremely long outages. The figure below illustrates in part, why this is the case.

Figure 2

PacifiCorp Thermal Plant Outage Duration: 2004-2008



Q. PLEASE EXPLAIN THE FIGURE ABOVE.

A. This chart shows the cumulative percentage of forced outages occurring as a function of outage duration. The data was based on all forced outages at PacifiCorp plants from July 2004 to June 2008.[13/] For example, more than half of these events were lasted for five hours or less. Ninety percent were 51 hours or less duration. Virtually all of the events that occurred (99.8%) were less than 672 hours (28 days) duration. This clearly establishes that outages

13/ This data was used because it is now considered "non-confidential" by the Company.

longer than 28 days are extremely rare and simply won't occur once every four years for a specific resource.

Q. PLEASE ELABORATE ON YOUR COMMENT THAT PACIFICORP SUPPORTED THE CAPPING OF OUTAGES AT 28 DAYS IN A RECENT OREGON CASE.

A. Oregon Docket UM 1355 was a generic investigation into methods to improve outage rate forecasts. Various proposals were made by the parties. PacifiCorp's final proposal was a "collar" mechanism that would eliminate extremely high or low outage rates from the four year average calculation. However, prior to applying its collar, PacifiCorp proposed to cap outage durations at 28 days.[14] If the annual average outage rate for the resource was still outside of a range based on historical data, the Company would further reduce the outage rate under its collar proposal.

Q. ARE YOU ADOPTING THE ENTIRE PACIFICORP OREGON COLLAR PROPOSAL?

A. No, the PacifiCorp proposal has not been accepted by regulators, and has various other unrelated defects. In the Oregon case there are several other competing alternatives and a decision is pending. In any case, capping the long outages at 28 days would result in an outage rate for 2009 that would be unlikely to require adjustment based on the PacifiCorp proposal. If any of the UM 1355 collar proposals were applied, however, it would only serve to further reduce the Lake Side and Colstrip outage rates.

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[14] Re OPUC Investigation Into Forecasting Forced Outage Rates for Electric Generating Units, OPUC Docket No. UM 1355, Supplemental Testimony of David J. Godfrey, PPL Exhibit No. 102 at 9 (July 24, 2009).

Q. WAS THIS TREATMENT OF LONG OUTAGES PREVIOUSLY REQUIRED BY THE OREGON COMMISSION?

A. Yes. In the final order in Oregon Docket UE 191, the OPUC stated as follows:

> The Company documents show that the anticipated duration of the resulting outage was five to seven weeks. An outage of that duration, no matter what the cause, is anomalous, and raises issues regarding its inclusion in normalized rates. In this case, we find that a 28-day period is a reasonable limit on the length of the outage for the purpose of calculating the TAM adjustment factor. To the extent the actual outage exceeded 28 days, the Company should make an appropriate adjustment to the outage rate used in running the GRID model.[15]

Q. WILL CAPPING FORCED OUTAGES AT 28 DAYS RESULT IN IMPROVED ACCURACY FOR OUTAGE RATE FORECASTS?

A. Yes. This issue was analyzed also in Oregon Docket UM 1355. Based on an analysis of four year moving average forecast of outage rates for PacifiCorp plants from 1989 to 2008, the use of the 28 day cap reduced the sum squared forecast error by more than 9% as compared to use of four year moving average based on the uncapped data. I also performed statistical tests to determine the validity of this accuracy gain. The results indicate that the accuracy improvement is statistically significant at the 99% percent confidence level.

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend the Commission limit the long 2009 Lake Side and Colstrip outages to 28 days. The impact of this adjustment is shown on Table 1.

15/ Re PacifiCorp's 2008 Transition Adjustment Mechanism, OPUC Docket No. UE 191, Order 07-446 at 21 (Oct. 17, 2007).

<u>Adjustment 8: Bridger Fuel Quality</u>

Q. CAN FUEL PROBLEMS CAUSE GENERATOR OUTAGES OR DERATIONS?

A. Yes. Fuel problems can result in a reduction to capacity, or a complete shutdown of a plant. Some problems, such as frozen or wet coal are caused by bad weather and are beyond the Company's control. However, fuel quality testing is a normal practice at all power plants and is intended to prevent output reductions, violation of air quality standards or damage to power plants. Utilities report to North American Electric Reliability Council ("NERC") the instances where fuel quality problems result in lost energy due to outages or derations.

Q. DOES IT APPEAR THAT PACIFICORP HAS PROBLEMS WITH FUEL QUALITY AT ANY OF ITS PLANTS?

A. There appears to be an inordinate number of derations at the Bridger plant related to fuel quality problems. Review of data from 2006-2009 shows that on average, the Company loses far more energy due to fuel quality issues at Bridger than any other plant. In fact, 78% of all energy lost due to fuel quality problems occurred at Bridger. Bridger fuel quality losses are more than twice the NERC average for comparably sized plants.

Q. WHAT IS YOUR RECOMMENDATION?

A. Bridger coal is produced at a Company owned captive mine. The level of fuel quality losses is excessive and both the production of coal and the operation of the plant are under the Company's direct control. Absent justification for these circumstances in its rebuttal case, I recommend the Commission disallow the additional costs resulting from this problem.

Q. HAVE YOU REVIEWED THE COMPANY'S COST INFORMATION FOR THE BRIDGER PLANT?

A. Yes. The Company also has included substantial costs in the test year related to management bonuses, employee meals and gifts and donations as part of the Bridger coal costs. Given the fuel quality issues at this plant, I believe it would be reasonable to require the Company to absorb these costs until it can demonstrate that its overall performance has improved. Adjustment 8 on Table 1 includes both of these adjustments.

<u>Adjustment 9: Naughton 3 Outage</u>

Q. PLEASE EXPLAIN THE BASIS FOR ADJUSTMENT 18.

A. This adjustment removes outage events that occurred at Naughton Unit 3 in April and May 2009 from the historical record used to compute outage rates for GRID. Exhibit 607 (page 2) is a copy of a recent discovery request[16/] concerning this event. Exhibit 608 (pages 6-9) is a copy of confidential discovery information from another discovery response[17/] demonstrating that the Company's contractor, [redacted] According to the Company, the contractor [redacted]

[16/] See Exhibit 607 at 2 (Response to ICNU DR 2.5).
[17/] See Exhibit 608 at 6-9 (Response to ICNU DR 2.3).

[redacted] Because the Company was compensated by Siemens for these problems, imprudence and/or negligence is not debatable. [redacted] Consequently, I made adjustments to both planned and forced outages.

Q. DOES THE LIQUIDATED DAMAGES PAYMENT COMPENSATE CUSTOMERS FOR THIS EVENT?

A. No. Replacement power costs were much higher and if the outage is included in the historical record for the next four years it would result in customers bearing substantially greater costs, at current market price levels.

<u>Adjustment 10: Heat Rate Deration Adjustment</u>

Q. WHAT IS THE PURPOSE OF ADJUSTMENT 10?

A. This adjustment adjusts heat rates so they are not artificially inflated due to the deration of unit maximum capacities used to model forced outages in GRID. A modeling technique designed to eliminate this problem is already used by at least one other regional utility, Portland General Electric ("PGE"), in its power cost model, MONET. I believe this represents standard industry practice, as do other experts. For example, in Utah Commission Docket No.

07-035-93, another power cost modeling expert, Mr. Philip Hayet, testified that the technique is well accepted in the community of production cost modeling experts.[18/] Further, this technique was recommended for application to PacifiCorp by OPUC Staff witness, Kelcey Brown in OPUC Docket UM 1355.[19/] Finally, PacifiCorp itself uses the same technique for modeling of fractionally owned units, such as Bridger and Colstrip. The adjustment I propose in this case is a simplification intended to partially address this issue.

Q. WHY IS AN ADJUSTMENT NECESSARY?

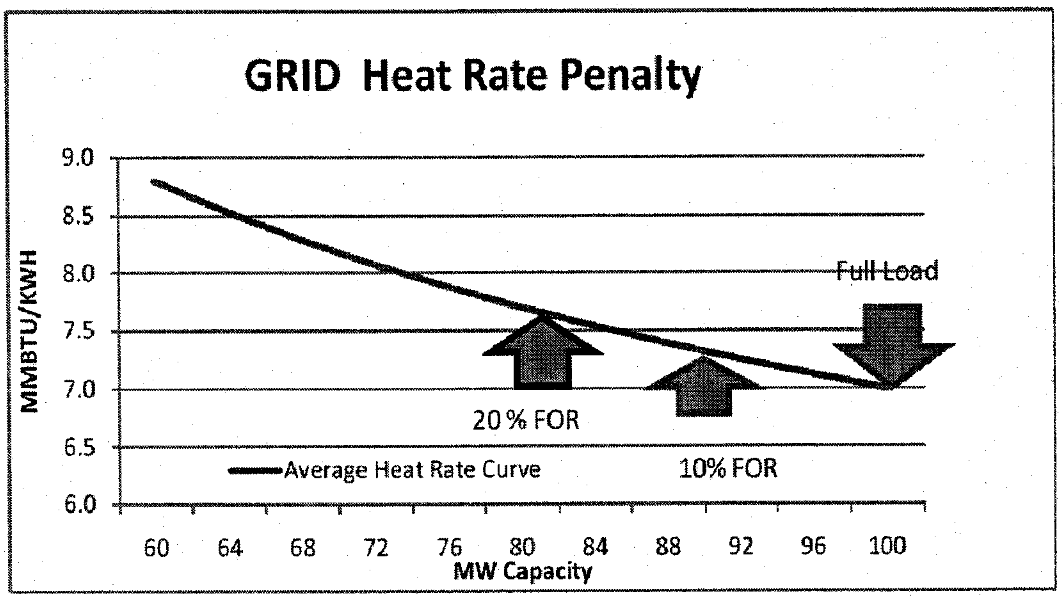
A. In GRID, and some other power cost models, forced outages are modeled by "shrinking" the capacity to account for outages. For example, a 100 MW unit with a 20% forced outage rate is seen as an 80 MW unit.

A problem with the GRID modeling is that when the capacity of units is derated to model outages, there is a mismatch with the heat rate curve. The chart below shows what happens when a heat rate curve sized for a 100 MW unit is applied to the now shrunken 80 MW unit. The unit artificially "moves up the heat rate curves" and efficiency appears to be reduced. As the forced outage rate increases for a unit, its heat rate normally increases in the GRID modeling. This, however, is highly unrealistic, as lengthening the period of a forced outage should have no effect on the resources average heat rates. The GRID method also "rewards" the Company for having high outage rates.

18/ Re Rocky Mountain Power 2007 General Rate Case, Utah Commission Docket No. 07-035-93, Direct Testimony of Philip Hayet, Exhibit No. CCS 5D at 25 (April 7, 2008).

19/ Re OPUC Investigation Into Forecasting Forced Outage Rates for Electric Generating Units, OPUC Docket No. UM 1355, Supplemental Reply Testimony of Kelcey Brown, Staff Exhibit No. 300 at 20 (August 13, 2009).

Figure 3



Q. DO YOU HAVE ANY DATA THAT ILLUSTRATES THIS PROBLEM?

A. Yes. When the long outage for the Lake Side plant, discussed above, was removed from the GRID database, the average heat rate for Lake Side was decreased by .9%. However, it stands to reason that the time spent when a plant is sitting idle should have no impact on its average heat. The fact that it does in GRID, is proof that this problem is real.

Q. HAS THE COMPANY ALREADY CONCEDED THERE IS VALIDITY TO THIS ARGUMENT?

A. In Oregon Docket UM 1355, the Company's witness, Mr. Gregory N. Duvall's testimony indicated he agreed that at least at the derated maximum capacity of a unit, the criticism was valid. Mr. Duvall testified that the solution I propose was not correct below the derated maximum capacity and that "the issue that ICNU is trying to address (i.e. the heat rate to use at the derated capacity level) is near zero in this example, and is not nearly as large as the error they create."[20] His testimony addressed different aspects of this problem, for which I proposed a more comprehensive solution in the Oregon case using the techniques alluded to above. The reference to the adjustment being "near zero" was based on the heat rate curve for a single plant, which was unrepresentative.

Q. DO YOU AGREE WITH THE COMPANY ABOUT THIS?

A. No. However, for purposes of this case, I will concentrate solely on the impact of the problem when generators are modeled as running at the derated maximum capacity, which the Company has apparently conceded.

Q. CAN YOU PROVIDE AN EXAMPLE WHICH ILLUSTRATES THIS PROBLEM?

A. Yes. The Confidential table below illustrates the problem. It shows the heat rate equation used in GRID for Bridger Unit 2. Based on the data used in GRID, the capacity of Unit 2 is approximately [redacted]. However, there are partial outage derations that occur, that lower the available capacity to [redacted] on average. These events do not result in shutdown of the plant, but do degrade the average heat rate in the field and should do so in GRID as well. Based on the average [redacted] capacity loading, the heat rate for the unit is [redacted] MMBTU/MWh.

20/ Re OPUC Investigation Into Forecasting Forced Outage Rates for Electric Generating Units, OPUC Docket No. UM 1355, Supplemental Testimony of Gregory N. Duvall, PPL Exhibit No. 405 at 19 (July 24, 2009).

In GRID, however, full forced outages are assumed to reduce the maximum available capacity of the unit by an additional [redacted] MW, resulting in a maximum derated capacity in GRID of [redacted] MW. When the GRID heat rate curve is applied, the result is [redacted] MMBTU/MWh. When the Bridger fuel cost difference is applied to the difference between the two heat rates, the resulting error is close to [redacted] This may seem like an inconsequential amount, however this problem occurs thousands of hours per year for nearly every unit and can become a very substantial sum of money.

[redacted]

Q. HAVE YOU PERFORMED AN ANALYSIS USING GRID THAT ISOLATES THE IMPACT OF THIS PROBLEM?

A. Yes. I isolated the effect based on only the hours when units were dispatched to the maximum derated capacity in GRID. I computed the hourly cost differences in the same manner as shown above. The result is the amount shown on Table 1.

Q. ARE THERE OTHER ASPECTS OF THIS PROBLEM?

A. Yes, as I mentioned above. This adjustment only isolates the problem at the high end of the heat rate curve. A similar problem exists at lower loadings. Further, the Company reduces the maximum capacity of units in GRID to model outages, but does not do so for the minimum loading levels. It is possible to implement a more comprehensive adjustment in GRID to address these issues. However, given the presence of a true-up which tends to mute the importance of modeling issues, and because Adjustment 10 captures the majority of the effect, I have not included the other components of this adjustment, in the interest of economy.

E. TRANSMISSION ISSUES

__Adjustment 11: DC Intertie Costs__

Q. WHAT IS THE PURPOSE OF THE DC INTERTIE CONTRACT?

A. [redacted]

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[21] Exhibit 608 at 1 (WUTC Docket No. UE-100749, Response to ICNU DR 1.33).

[redacted]

Q. WHAT IS YOUR RECOMMENDATION?

A. This contract should be removed from the test year to match costs and benefits. There are few, if any, transactions that rely on this contract. Presumably, in actual practice the Company would not make such purchases unless they resulted in cost savings. The contract may provide compensating benefits, but because the test year is largely based on projected data there are none that can be identified and included at this time. However, it is possible that if the contract is not really useful to the Company any longer, it may be the Company should consider selling its rights, or seeking to escape from it. Transmission capacity in the region is limited, and it is hard to imagine that this important link has no value. The Company should be required to demonstrate the prudence of its management of this contract in the next ECAM true-up.

22/ Exhibit 609 (WUTC Docket No. UE-100749, Response to ICNU DR 10.3).

Adjustment 12 – Populus to Ben Lomond Line Loss Adjustment

Q. ARE YOU TAKING A POSITION REGARDING THE RATE TREATMENT OF THE POPULUS TO BEN LOMOND LINE IN THIS CASE?

A. No. The issues related to timing, prudence and used and usefulness of the line are beyond the scope of my testimony and presumably will be addressed by other witnesses. However, if the Commission chooses to include the line in rates, there are certain issues that should be addressed.

Q. WILL THE POPULUS TO BEN LOMOND LINE REDUCE LOSSES?

A. Yes. The Company agrees that the line would produce a reduction in losses.[23/] One of the advantages of using higher voltages is that losses are reduced. This follows from the equation $P_{Loss} = P^2R/V^2$. However, the above equation is appropriate for a single line viewed in isolation, but is not directly applicable in the case of a complex transmission network.[24/] The Company has produced an estimate indicating that at a 700 MW loading, savings in losses with the Ben Lomond line in place would amount to 10.8 MW based on a load flow study.[25/]

Q. HOW DID YOU QUANTIFY THE LOSS REDUCTIONS?

A. I assumed that most of the savings were the result of higher voltages on the segment covered by the Populus to Ben Lomond line. I therefore computed the reduction in losses based on the squared ratio of loadings on the line. For

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23/ See Exhibit 606 (Utah Commission Docket No. 10-035-89, Response to OCS DR 2.5, 6.5, and 6.7).

24/ Id.

25/ Id.

example, when the line was loaded to 700 MW, the loss reduction was 10.8 MW. If the loading was 600 MW, the loss reduction was $(600/700)^2*10.8$.[26/] I computed these savings on an hourly basis outside of GRID, though I expect results using GRID would be quite close. The results are shown on Table 1. I believe this is a reasonable, if not conservative, approach, but would certainly welcome input from the Company on this matter.

Adjustment 13: Transmission Contract Adjustment

Q. DOES COMPLETION OF THE POPULUS TO BEN LOMOND LINE REDUCE THE NEED FOR PURCHASED TRANSMISSION CAPACITY?

A. Yes. The Company will no longer need some of the short term firm and contract capacity it is purchasing, once the new line is completed. There is a 61MW contract that expires [redacted] of the new transmission line.

Q. IS THE 61 MW CONTRACT NEEDED AFTER COMPLETION OF THE POPULUS TO BEN LOMOND LINE?

A. No, for two reasons. First, it produces no economic benefits in the GRID study. Second, if capacity were actually needed for reliability purposes, it would be far more cost effective to purchase 61 MW of STF capacity.[27/]

Q. DID YOU EXPLORE THIS ISSUE IN DISCOVERY?

A. Yes. While the Company does not agree that the new line eliminates the need for the 61 MW contract, it does not indicate the contract would be extended. Instead the Company merely indicated it would study whether the additional

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26/ This method turns out to be more conservative than simply using the ratio of the loadings.

27/ See Exhibit 606 at 2 (Response to OCS DR 6.2).

capacity was needed in the future.[28/] Conversely, in other discovery responses,[29/] the Company clearly indicated it would require additional capacity if the Populus to Ben Lomond line was delayed. I believe that this demonstrates the avoidance of this high cost transmission contract is one of the benefits of the line that should be included as a part of the pro-forma adjustment to reflect all of the costs and system benefits of the project, assuming it is included in the test year. The impact of this adjustment is shown on Table 1.

F. NON FUEL START UP O&M

Q. IS ADJUSTMENT 14 DISCUSSED ABOVE A NPC ADJUSTMENT?

A. No. It is a reduction to non-fuel O&M and is not in one of the accounts included in the definition of NPC. For this reason, it is included at the bottom of Table 1, and not part of the NPC adjustments listed. However, these are legitimate test year costs, so they should be reflected in the test year, as discussed above.

G. RECOMMENDED FILING REQUIREMENTS AND WORKPAPERS

Q. DOES ICNU HAVE ANY OTHER RECOMMENDATIONS?

A. Yes. In stipulations in Oregon Docket UE 199, Washington Docket UE-090205 and Wyoming Docket 20000-341-EP-09, PacifiCorp has agreed to provide certain workpapers and supporting documents at specific times, as well as immediate access to the GRID model with its filings. Experience with

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28/ Id.

29/ See Exhibit 606 at 3 (Response to OCS DR 6.3).

these requirements in other states has become increasingly positive as time passes. Exhibit 609 provides a copy of the documents agreement related to the filing requirements from Washington. I recommend comparable workpaper filings be required for Idaho as well.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

Case. No. PAC-E-10-07
Exhibit No. 605
Witness: Randall J. Falkenberg

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

PACIFICORP IDAHO INDUSTRIAL CUSTOMERS

Exhibit Accompanying Direct Testimony of Randall J. Falkenberg

Qualifications of Randall J. Falkenberg

October 14, 2010

QUALIFICATIONS OF RANDALL J. FALKENBERG, PRESIDENT

EDUCATIONAL BACKGROUND

I received my Bachelor of Science degree with Honors in Physics and a minor in mathematics from Indiana University. I received a Master of Science degree in Physics from the University of Minnesota. My thesis research was in nuclear theory. At Minnesota I also did graduate work in engineering economics and econometrics. I have completed advanced study in power system reliability analysis.

PROFESSIONAL EXPERIENCE

After graduating from the University of Minnesota in 1977, I was employed by Minnesota Power as a Rate Engineer. I designed and coordinated the Company's first load research program. I also performed load studies used in cost-of-service studies and assisted in rate design activities.

In 1978, I accepted the position of Research Analyst in the Marketing and Rates department of Puget Sound Power and Light Company. In that position, I prepared the two-year sales and revenue forecasts used in the Company's budgeting activities and developed methods to perform both near- and long-term load forecasting studies.

In 1979, I accepted the position of Consultant in the Utility Rate Department of Ebasco Service Inc. In 1980, I was promoted to Senior Consultant in the Energy Management Services Department. At Ebasco I performed and assisted in numerous studies in the areas of cost of service, load research, and utility planning. In particular, I was involved in studies concerning analysis of excess capacity, evaluation of the planning activities of a major utility on behalf of its public service commission, development of a methodology for computing avoided costs and cogeneration rates, long-term electricity price forecasts, and cost allocation studies.

At Ebasco, I specialized in the development of computer models used to simulate utility production costs, system reliability, and load patterns. I was the principal author of production costing software used by eighteen utility clients and public service commissions for evaluation of marginal costs, avoided costs and production costing analysis. I assisted over a dozen utilities in the performance of marginal and avoided cost studies related to the PURPA of 1978. In this capacity, I worked with utility planners and rate specialists in quantifying the rate and cost impact of generation expansion alternatives. This activity included estimating carrying costs, O&M expenses, and capital cost estimates for future generation.

In 1982 I accepted the position of Senior Consultant with Energy Management Associates, Inc. and was promoted to Lead Consultant in June 1983. At EMA I trained and consulted with planners and financial analysts at several utilities in applications of the PROMOD and PROSCREEN planning models. I assisted planners in applications of these models to the preparation of studies evaluating the revenue requirements

QUALIFICATIONS OF RANDALL J. FALKENBERG, PRESIDENT

and financial impact of generation expansion alternatives, alternate load growth patterns and alternate regulatory treatments of new baseload generation. I also assisted in EMA's educational seminars where utility personnel were trained in aspects of production cost modeling and other modern techniques of generation planning.

I became a Principal in Kennedy and Associates in 1984. Since then I have performed numerous economic studies and analyses of the expansion plans of several utilities. I have testified on several occasions regarding plant cancellation, power system reliability, phase-in of new generating plants, and the proper rate treatment of new generating capacity. In addition, I have been involved in many projects over the past several years concerning the modeling of market prices in various regional power markets.

In January 2000, I founded RFI Consulting, Inc. whose practice is comparable to that of my former firm, J. Kennedy and Associates, Inc.

The testimony that I present is based on widely accepted industry standard techniques and methodologies, and unless otherwise noted relies upon information obtained in discovery or other publicly available information sources of the type frequently cited and relied upon by electric utility industry experts. All of the analyses that I perform are consistent with my education, training and experience in the utility industry. Should the source of any information presented in my testimony be unclear to the reader, it will be provided it upon request by calling me at 770-379-0505.

PAPERS AND PRESENTATIONS

Mid-America Regulatory Commissioners Conference - June 1984: "Nuclear Plant Rate Shock - Is Phase-In the Answer"

Electric Consumers Resource Council - Annual Seminar, September 1986: "Rate Shock, Excess Capacity and Phase-in"

The Metallurgical Society - Annual Convention, February 1987: "The Impact of Electric Pricing Trends on the Aluminum Industry"

Public Utilities Fortnightly - "Future Electricity Supply Adequacy: The Sky Is Not Falling" What Others Think, January 5, 1989 Issue

Public Utilities Fortnightly - "PoolCo and Market Dominance", December 1995 Issue

QUALIFICATIONS OF RANDALL J. FALKENBERG, PRESIDENT

APPEARANCES

3/84	8924	KY	Airco Carbide	Louisville Gas & Electric	CWIP in rate base.
5/84	830470-EI	FL	Florida Industrial Power Users Group	Fla. Power Corp.	Phase-in of coal unit, fuel savings basis, cost allocation.
10/84	89-07-R	CT	Connecticut Ind. Energy Consumers	Connecticut Light & Power	Excess capacity.
11/84	R-842651	PA	Lehigh Valley	Pennsylvania Power Committee	Phase-in of nuclear unit. Power & Light Co.
2/85 cancellation of	I-840381	PA	Phila. Area Ind. Energy Users' Group	Electric Co.	Philadelphia Economics of nuclear generating units.
3/85	Case No. 9243	KY	Kentucky Industrial Utility Consumers	Louisville Gas & Electric Co.	Economics of cancelling fossil generating units.
3/85	R-842632	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Economics of pumped storage generating units, optimal res. margin, excess capacity.
3/85	3498-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	Nuclear unit cancellation, load and energy forecasting, generation economics.
5/85	84-768-E-42T	WV	West Virginia Multiple Intervenors	Monongahela Power Co.	Economics - pumped storage generating units, reserve margin, excess capacity.
7/85	E-7, SUB 391	NC	Carolina Industrial Group for Fair Utility Rates	Duke Power Co.	Nuclear economics, fuel cost projections.
7/85	9299	KY	Kentucky Industrial Utility Consumers	Union Light, Heat & Power Co.	Interruptible rate design.
8/85	84-249-U	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Prudence review.
1/86	85-09-12	CT	Connecticut Ind. Energy Consumers	Connecticut Light & Power Co.	Excess capacity, financial impact of phase-in nuclear plant.
1/86	R-850152	PA	Philadelphia Area Industrial Energy Users' Group	Philadelphia Electric Co.	Phase-in and economics of nuclear plant.
2/86	R-850220	PA	West Penn Power Industrial Intervenors	West Penn Power	Optimal reserve margins, prudence, off-system sales guarantee plan.
5/86	86-081-E-GI	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Generation planning study, economics prudence of a pumped storage hydroelectric unit.
5/86	3554-U	GA	Attorney General & Georgia Public Service Commission Staff	Georgia Power Co.	Cancellation of nuclear plant.
9/86	29327/28	NY	Occidental Chemical Corp.	Niagara Mohawk Power Co.	Avoided cost, production cost models.

**Expert Testimony Appearances
of
Randall J. Falkenberg**

Date	Case	Jurisdict.	Party	Utility	Subject
9/86	E7-Sub 408	NC	NC Industrial Energy Committee	Duke Power Co.	Incentive fuel adjustment clause.
12/86	9437/ 613	KY	Attorney General of Kentucky	Big Rivers Elect. Corp.	Power system reliability analysis, rate treatment of excess capacity.
5/87	86-524-E-SC	WV	West Virginia Energy Users' Group	Monongahela Power	Economics and rate treatment of Bath County pumped storage County Pumped Storage Plant.
6/87	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Prudence of River Bend Nuclear Plant.
6/87	PUC-87-013-RD E002/E-015 -PA-86-722	MN	Eveleth Mines & USX Corp.	Minnesota Power/ Northern States	Sale of generating unit and reliability Power requirements.
7/87	Docket 9885	KY	Attorney General of Kentucky	Big Rivers Elec. Corp.	Financial workout plan for Big Rivers.
8/87	3673-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	Nuclear plant prudence audit, Vogtle buyback expenses.
10/87	R-850220	PA	WPP Industrial Intervenors	West Penn Power	Need for power and economics, County Pumped Storage Plant
10/87	870220-EI	FL	Occidental Chemical	Fla. Power Corp.	Cost allocation methods and interruptible rate design.
10/87	870220-EI	FL	Occidental Chemical	Fla. Power Corp.	Nuclear plant performance.
1/88	Case No. 9934	KY	Kentucky Industrial Utility Consumers	Louisville Gas & Electric Co.	Review of the current status of Trimble County Unit 1.
3/88	870189-EI	FL	Occidental Chemical Corp.	Fla. Power Corp.	Methodology for evaluating interruptible load.
5/88	Case No. 10217	KY	National Southwire Aluminum Co., ALCAN Alum Co.	Big Rivers Elec. Corp.	Debt restructuring agreement.
7/88	Case No. 325224	LA Div. I 19th Judicial District	Louisiana Public Service Commission Staff	Gulf States Utilities	Prudence of River Bend Nuclear Plant.
10/88	3780-U	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Co.	Weather normalization gas sales and revenues.
10/88	3799-U	GA	Georgia Public Service Commission Staff	United Cities Gas Co.	Weather normalization of gas sales and revenues.
12/88	88-171-EL-AIR 88-170-EL-AIR	OH OH	Ohio Industrial Energy Consumers	Toledo Edison Co., Cleveland Electric Illuminating Co.	Power system reliability reserve margin.

**Expert Testimony Appearances
of
Randall J. Falkenberg**

Date	Case	Jurisdict.	Party	Utility	Subject
1/89	I-880052	PA	Philadelphia Area Industrial Energy Users' Group	Philadelphia Electric Co.	Nuclear plant outage, replacement fuel cost recovery.
2/89	10300	KY	Green River Steel K	Kentucky Util.	Contract termination clause and interruptible rates.
3/89	P-870216 283/284/286	PA	Armco Advanced Materials Corp., Allegheny Ludlum Corp.	West Penn Power	Reserve margin, avoided costs.
5/89	3741-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	Prudence of fuel procurement.
8/89	3840-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	Need and economics coal & nuclear capacity, power system planning.
10/89	2087	NM	Attorney General of New Mexico	Public Service Co. of New Mexico	Power system planning, economic and reliability analysis, nuclear planning, prudence.
10/89	89-128-U	AR	Arkansas Electric Energy Consumers	Arkansas Power Light Co.	Economic impact of asset transfer and stipulation and settlement agreement.
11/89	R-891364	PA	Philadelphia Area Industrial Energy Users' Group	Philadelphia Electric Co.	Sale/leaseback nuclear plant, excess capacity, phase-in delay imprudence.
1/90	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Sale/leaseback nuclear power plant.
4/90	89-1001-EL-AIR	OH	Industrial Energy Consumers	Ohio Edison Co.	Power supply reliability, excess capacity adjustment.
4/90	N/A	N.O.	New Orleans Business Counsel	New Orleans Public Service Co.	Municipalization of investor-owned utility, generation planning & reliability
7/90	3723-U	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Co.	Weather normalization adjustment rider.
9/90	8278	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Revenue requirements gas & electric, CWIP in rate base.
9/90	90-158	KY	Kentucky Industrial Utility Consumers	Louisville Gas & Electric Co.	Power system planning study.
12/90	U-9346	MI	Association of Businesses Advocating Tariff Equity (ABATE)	Consumers Power	DSM Policy Issues.
5/91	3979-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	DSM, load forecasting and IRP.
7/91	9945	TX	Office of Public Utility Counsel	El Paso Electric Co.	Power system planning, quantification of damages of imprudence, environmental cost of

**Expert Testimony Appearances
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Date	Case	Jurisdict.	Party	Utility	Subject
					electricity
8/91	4007-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	Integrated resource planning, regulatory risk assessment.
11/91	10200	TX	Office of Public	Texas-New Mexico Utility Counsel	Imprudence disallowance. Power Co.
12/91	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Year-end sales and customer adjustment, jurisdictional allocation.
1/92	89-783-E-C	WVA	West Virginia Energy Users Group	Monongahela Power Co.	Avoided cost, reserve margin, power plant economics.
3/92	91-370	KY	Newport Steel Co.	Union Light, Heat & Power Co.	Interruptible rates, design, cost allocation.
5/92	91890	FL	Occidental Chemical Corp.	Fla. Power Corp.	Incentive regulation, jurisdictional separation, interruptible rate design.
6/92	4131-U	GA	Georgia Textile Manufacturers Assn.	Georgia Power Co.	Integrated resource planning, DSM.
9/92	920324	FL	Florida Industrial Power Users Group	Tampa Electric Co.	Cost allocation, interruptible rates decoupling and DSM.
10/92	4132-U	GA	Georgia Textile Manufacturers Assn.	Georgia Power Co.	Residential conservation program certification.
10/92	11000	TX	Office of Public Utility Counsel	Houston Lighting and Power Co.	Certification of utility cogeneration project.
11/92	U-19904	LA	Louisiana Public Service Commission Staff	Entergy/Gulf States Utilities (Direct)	Production cost savings from merger.
11/92	8469	MD	Westvaco Corp.	Potomac Edison Co.	Cost allocation, revenue distribution.
11/92	920606	FL	Florida Industrial Power Users Group	Statewide Rulemaking	Decoupling, demand-side management, conservation, Performance incentives.
12/92	R-009 22378	PA	Armco Advanced Materials	West Penn Power	Energy allocation of production costs.
1/93	8179	MD	Eastalco Aluminum/ Westvaco Corp.	Potomac Edison Co.	Economics of QF vs. combined cycle power plant.
2/93	92-E-0814 88-E-081	NY	Occidental Chemical Corp.	Niagara Mohawk Power Corp.	Special rates, wheeling.
3/93	U-19904	LA	Louisiana Public Service Commission Staff	Entergy/Gulf States Utilities (Surrebuttal)	Production cost savings from merger.
4/93	EC92 21000 ER92-806-000	FERC	Louisiana Public Service Commission Staff	Gulf States Utilities/Entergy	GSU Merger prodcution cost savings

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Date	Case	Jurisdict.	Party	Utility	Subject
6/93	930055-~~EU~~ ~~FL~~		Florida Industrial Power Users' Group	Statewide Rulemaking	Stockholder incentives for off-system sales.
9/93	92-490, 92-490A, 90-360-C	KY	Kentucky Industrial Utility Customers & Attorney General	Big Rivers Elec. Corp.	Prudence of fuel procurement decisions.
9/93	4152-U	GA	Georgia Textile Manufacturers Assn.	Georgia Power Co.	Cost allocation of pollution control equipment.
4/94	E-015/ GR-94-001	MN	Large Power Intervenors	Minn. Power Co.	Analysis of revenue req. and cost allocation issues.
4/94	93-465	KY	Kentucky Industrial Utility Customers	Kentucky Utilities	Review and critique proposed environmental surcharge.
4/94	4895-U	GA	Georgia Textile Manufacturers Assn.	Georgia Power Co	Purchased power agreement and fuel adjustment clause.
4/94	E-015/ GR-94-001	MN	Large Power Intervenors	Minnesota Power Light Co.	Rev. requirements, incentive compensation.
7/94	94-0035-E-42T	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Revenue annualization, ROE performance bonus, and cost allocation.
8/94	8652	MD	Westvaco Corp.	Potomac Edison Co.	Revenue requirements, ROE performance bonus, and revenue distribution.
1/95	94-332	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Company	Environmental surcharge.
1/95	94-996-EL-AIR	OH	Industrial Energy Users of Ohio	Ohio Power Company	Cost-of-service, rate design, demand allocation of power
3/95	E999-CI	MN	Large Power Intervenor	Minnesota Public Utilities Comm.	Environmental Costs Of electricity
4/95	95-060	KY	Kentucky Industrial Utility Customers	Kentucky Utilities Company	Six month review of CAAA surcharge.
11/95	I-940032	PA	The Industrial Energy Consumers of Pennsylvania	Statewide - all utilities	Direct Access vs. Poolco, market power.
11/95	95-455	KY	Kentucky Industrial	Kentucky Utilities	Clean Air Act Surcharge,
12/95	95-455	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Company	Clean Air Act Compliance Surcharge.
6/96	960409-EI	FL	Florida Industrial Power Users Group	Tampa Electric Co.	Polk County Power Plant Rate Treatment Issues.
3/97	R-973877	PA	PAIEUG.	PECO Energy	Stranded Costs & Market Prices.
3/97	970096-EQ	FL	FIPUG	Fla. Power Corp.	Buyout of QF Contract
6/97	R-973593	PA	PAIEUG	PECO Energy	Market Prices, Stranded Cost
7/97	R-973594	PA	PPLICA	PP&L	Market Prices, Stranded Cost

Expert Testimony Appearances
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Date	Case	Jurisdict.	Party	Utility	Subject
8/97	96-360-U	AR	AEEC	Entergy Ark. Inc.	Market Prices and Stranded Costs, Cost Allocation, Rate Design
10/97	6739-U	GA	GPSC Staff	Georgia Power	Planning Prudence of Pumped Storage Power Plant
10/97	R-974008 R-974009	PA	MIEUG PICA	Metropolitan Ed. PENELEC	Market Prices, Stranded Costs
11/97	R-973981	PA	WPII	West Penn Power	Market Prices, Stranded Costs
11/97	R-974104	PA	DII	Duquesne Light Co.	Market Prices, Stranded Costs
2/98	APSC 97451 97452 97454	AR	AEEC	Generic Docket	Regulated vs. Market Rates, Rate Unbundling, Timetable for Competition
7/98	APSC 87-166	AR	AEEC	Entergy Ark. Inc.	Nuclear decommissioning cost estimates & rate treatment.
9/98	97-035-01	UT	DPS and CCS	PacifiCorp	Net Power Cost Stipulation, Production Cost Model Audit
12/98	19270	TX	OPC	HL&P	Reliability, Load Forecasting
4/99	19512	TX	OPC	SPS	Fuel Reconciliation
4/99	99-02-05	CT	CIEC	CL&P	Stranded Costs, Market Prices
4/99	99-03-04	CT	CIEC	UI	Stranded Costs, Market Prices
6/99	20290	TX	OPC	CP&L	Fuel Reconciliation
7/99	99-03-36	CT	CIEC	CL&P	Interim Nuclear Recovery
7/99	98-0453	WV	WVEUG	AEP & APS	Stranded Costs, Market Prices
12/99	21111	TX	OPC	EGSI	Fuel Reconciliation
2/00	99-035-01	UT	CCS	PacifiCorp	Net Power Costs, Production Cost Modeling Issues
5/00	99-1658	OH	AK Steel	CG&E	Stranded Costs, Market Prices
6/00	UE-111	OR	ICNU	PacifiCorp	Net Power Costs, Production Cost Modeling Issues
9/00	22355	TX	OPC	Reliant Energy	Stranded cost
10/00	22350	TX	OPC	TXU Electric	Stranded cost
10/00	99-263-U	AR	Tyson Foods	SW Elec. Coop	Cost of Service
12/00	99-250-U	AR	Tyson Foods	Ozarks Elec. Coop	Cost of Service
01/01	00-099-U	AR	Tyson Foods	SWEPCO	Rate Unbundling
02/01	99-255-U	AR	Tyson Foods	Ark. Valley Coop	Rate Unbundling
03/01	UE-116	OR	ICNU	PacifiCorp	Net Power Costs
6/01	01-035-01	UT	DPS and CCS	PacifiCorp	Net Power Costs

Expert Testimony Appearances
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Date	Case	Jurisdict.	Party	Utility	Subject
7/01	A.01-03-026	CA	Roseburg FP	PacifiCorp	Net Power Costs
7/01	23550	TX	OPC	EGSI	Fuel Reconciliation
7/01	23950	TX	OPC	Reliant Energy	Price to beat fuel factor
8/01	24195	TX	OPC	CP&L	Price to beat fuel factor
8/01	24335	TX	OPC	WTU	Price to beat fuel factor
9/01	24449	TX	OPC	SWEPCO	Price to beat fuel factor
10/01	20000-EP 01-167	WY	WIEC	PacifiCorp	Power Cost Adjustment Excess Power Costs
2/02	UM-995	OR	ICNU	PacifiCorp	Cost of Hydro Deficit
2/02	00-01-37	UT Plant	CCS	PacifiCorp	Certification of Peaking
4/02	00-035-23	UT	CCS	PacifiCorp	Cost of Plant Outage, Excess Power Cost Stipulation.
4/02	01-084/296	AR	AEEC	Entergy Arkansas	Recovery of Ice Storm Costs
5/02	25802	TX	OPC	TXU Energy	Escalation of Fuel Factor
5/02	25840	TX	OPC	Reliant Energy	Escalation of Fuel Factor
5/02	25873	TX	OPC	Mutual Energy CPL	Escalation of Fuel Factor
5/02	25874	TX	OPC	Mutual Energy WTU	Escalation of Fuel Factor
5/02	25885	TX	OPC	First Choice	Escalation of Fuel Factor
7/02	UE-139	OR	ICNU	Portland General	Power Cost Modeling
8/02	UE-137	OP	ICNU	Portland General	Power Cost Adjustment Clause
10/02	RPU-02-03	IA	Maytag, et al	Interstate P&L	Hourly Cost of Service Model
11/02	20000-Er 02-184	WY	WIEC	PacifiCorp	Net Power Costs, Deferred Excess Power Cost
12/02	26933	TX	OPC	Reliant Energy	Escalation of Fuel Factor
12/02	26195	TX	OPC	Centerpoint Energy	Fuel Reconciliation
1/03	27167	TX	OPC	First Choice	Escalation of Fuel Factor
1/03	UE-134	OR	ICNU	PacifiCorp	West Valley CT Lease payment
1/03	27167	TX	OPC	First Choice	Escalation of Fuel Factor
1/03	26186	TX	OPC	SPS	Fuel Reconciliation
2/03	UE-02417	WA	ICNU	PacifiCorp	Rate Plan Stipulation, Deferred Power Costs
2/03	27320	TX	OPC	Reliant Energy	Escalation of Fuel Factor
2/03	27281	TX	OPC	TXU Energy	Escalation of Fuel Factor
2/03	27376	TX	OPC	CPL Retail Energy	Escalation of Fuel Factor

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Date	Case	Jurisdict.	Party	Utility	Subject
2/03	27377	TX	OPC	WTU Retail Energy	Escalation of Fuel Factor
3/03	27390	TX	OPC	First Choice	Escalation of Fuel Factor
4/03	27511	TX	OPC	First Choice	Escalation of Fuel Factor
4/03	27035	TX	OPC	AEP Texas Central	Fuel Reconciliation
05/03	03-028-U	AR	AEEC	Entergy Ark., Inc.	Power Sales Transaction
7/03	UE-149	OR	ICNU	Portland General	Power Cost Modeling
8/03	28191	TX	OPC	TXU Energy	Escalation of Fuel Factor
11/03	20000-ER -03-198	WY	WIEC	PacifiCorp	Net Power Costs
2/04	03-035-29	UT	CCS	PacifiCorp	Certification of CCCT Power Plant, RFP and Bid Evaluation
6/04	29526	TX	OPC	Centerpoint	Stranded cost true-up.
6/04	UE-161	OR	ICNU	Portland General	Power Cost Modeling
7/04	UM-1050	OR	ICNU	PacifiCorp	Jurisdictional Allocation
10/04	15392-U 15392-U	GA	Calpine	Georgia Power/ SEPCO	Fair Market Value of Combined Cycle Power Plant
12/04	04-035-42	UT	CCS		PacifiCorp Net power costs
02/05	UE-165	OP	ICNU	Portland General	Hydro Adjustment Clause
05/05	UE-170	OR	ICNU	PacifiCorp	Power Cost Modeling
7/05	UE-172	OR	ICNU	Portland General	Power Cost Modeling
08/05	UE-173	OR	ICNU	PacifiCorp	Power Cost Adjustment
8/05	UE-050482	WA	ICNU	Avista	Power Cost modeling, Energy Recovery Mechanism
8/05	31056	TX	OPC	AEP Texas Central	Stranded cost true-up.
11/05	UE-05684	WA	ICNU	PacifiCorp	Power Cost modeling, Jurisdictional Allocation, PCA
2/06	05-116-U	AR	AEEC	Entergy Arkansas	Fuel Cost Recovery
4/06	UE-060181	WA	ICNU	Avista	Energy Cost Recovery Mechanism
5/06	22403-U	GA	GPSC Staff	Georgia Power	Fuel Cost Recovery Audit
6/06	UM 1234	OR	ICNU	Portland General	Deferral of outage costs
6/06	UE 179	OR	ICNU	PacifiCorp	Power Costs, PCAM
7/06	UE 180	OR	ICNU	Portland General	Power Cost Modeling, PCAM
12/06	32766	TX	OPC	SPS	Fuel Reconciliation
1/07	23540-U	GA	GPSC Staff	Georgia Power	Fuel Cost Recovery Audit
2/07	06-101-U	AR	AEEC	Entergy Arkansas	Cost Allocation and Recovery
2/07	UE-061546	WA	ICNU/Public Counsel	PacifiCorp	Power Cost Modeling, Jurisdictional Allocation, PCA

Expert Testimony Appearances of Randall J. Falkenberg

Date	Case	Jurisdict.	Party	Utility	Subject
2/07	32710	TX	OPC	EGSI	Fuel Reconciliation
6/07	UE 188	OR	ICNU	Portland General	Wind Generator Rate Surcharge
6/07	UE 191	OR	ICNU	PacifiCorp	Power Cost Modeling
6/07	UE 192	OR	ICNU	Portland General	Power Cost Modeling
9/07	UM 1330	OR	ICNU	PGE, PacifiCorp	Renewable Resource Tariff
10/07	06-152-U	AR	AEEC	EAI	CA Rider, Plant Acquisition
10/07	07-129-U	AR	AEEC	EAI	Annual Earnings Review Tariff
10/07	06-152-U	AR	AEEC	EAI	Purchase of combined cycle power plant.
04/08	26794	GA	GPSC Staff	Georgia Power	Fuel Cost Recovery Case
04/08	07-035-93	UT	CCS	PacifiCorp	Power Cost Modeling
07/08	UE 200	OR	ICNU	PacifiCorp	Renewable Adjustment Clause
08/08	20000-315 -EP-08	WY	WIEC	PacifiCorp	Power Cost Adjustment Mechanism
01/09	20000-333 -ER-08	WY	WIEC	PacifiCorp	Power Cost Modeling/Wind resource prudence
02/09	08-035-38	UT	CCS	PacifiCorp	Power Cost Modeling/Wind resource prudence
04/09	UM 1355	OR	ICNU	PGE/PacifiCorp	Outage Rate Modeling
04/09	UM 1396	OR	ICNU	PGE/PacifiCorp	Avoided Costs
06/09	UE 199	OR	ICNU	PacifiCorp	Power Cost Modeling
07/09	UE 207	OR	ICNU	PacifiCorp	Power Cost Modeling
07/09	UE 208	OR	ICNU	PGE	Power Cost Modeling
07/09	UE 210	OR	ICNU	PacifiCorp	Transition Adjustment Mechanism
10/09	UM 1442/ 1443	OR	ICNU	PGE/PacifiCorp	Avoided Costs
10/09	09-035-23	UT	OCS	PacifiCorp	Power Cost Modeling
12/09	UM 1465		ICNU	PacifiCorp	Power Cost Deferral
1/10	20000-352-ER-09	WY	WIEC	PacifiCorp	Power Costs, Wind Resources
2/10	09-084-U	AR	AEEC	Entergy AR	Rate Spread, Formula Rate Plan
3/10	20000-363-ep-10	WY	WIEC	PacifiCorp	PCAM
4/10	10-035-13	UT	OCS	PacifiCorp	Power impact of Major Plant Additions

Case. No. PAC-E-10-07
Exhibit No. 606
Witness: Randall J. Falkenberg

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

PACIFICORP IDAHO INDUSTRIAL CUSTOMERS

Exhibit Accompanying Direct Testimony of Randall J. Falkenberg

Rocky Mountain Power Data Responses to OCS

October 14, 2010

10-035-89/Rocky Mountain Power
September 7, 2010
OCS Data Request 2.5

OCS Data Request 2.5

Does the Company expect that the Populus to Ben Lomond link will reduce losses? If so, please quantify the amount of annual energy loss savings expected. Please provide supporting details.

Response to OCS Data Request 2.5

Yes. New transmission capacity will reduce system losses as it also reduces path impedance. Losses are calculated on an annual system basis using averages for loads, generation, and system wheeling values. A new system loss study will be completed later this year. At this time definitive information as requested is not available.

OCS Data Request 6.2

Please refer to the answers to OCS 2.2. Does the Company agree that owing to the completion of the Populus to Ben Lomond link, it will no longer need the 61 MW contract? Please provide the termination date for the contract. Please fully explain your answer.

Response to OCS Data Request 6.2

No. The Company will evaluate its need of long term wheeling rights based on obligation to serve load and the FERC requirement not to use allocated network transmission for wholesale transactions. Please refer to the confidential attachment provided in the Company's response to OCS 6.1, for information regarding the contract.

10-035-89/Rocky Mountain Power
September 27, 2010
OCS Data Request 6.3

OCS Data Request 6.3

Please refer to the answers to OCS 2.2. If the Populus to Ben Lomond line were delayed for two years, is it likely that the Company would continue to purchase capacity from the market, if it were possible to extend both the STF contracts and the 61 MW contract?

Response to OCS Data Request 6.3

Yes.

OCS Data Request 6.5

Please refer to the answers to OCS 2.5. This answer is not responsive. A request was made for quantification of the expected savings in losses attributable to the Populus to Ben Lomond link. Please provide the Company's best estimate of the benefit in terms of loss reductions, attributable to the new line.

Response to OCS Data Request 6.5

Losses are measured based upon actual hourly power flows across the entire PacifiCorp network over time. Generation, loads, and actual line path flows vary hourly through time as generation and load pattern conditions change. System losses are also affected by the electrical reconfiguration of the system necessary to interconnect Populus, Ben Lomond and Terminal substations to all the new and existing 345 kV lines. The time period under which losses are incurred may vary as well; from one hour to one year, to 30 or more years.

The Company has created an estimate of loss reduction based upon the following assumptions. A power flow simulation was performed for year 2010 heavy summer load configuration without the Populus to Ben Lomond project. A one hour power flow simulation was conducted for a simulated power transfer of 700 MW across path C in the North to South direction. The load and system losses for the portion of the system between Populus and Terminal substations were calculated for that single hour resulting in Load + System Losses = 1300.7 MW.

A second power flow simulation was conducted using the same year 2010 configuration and assumptions using the same power flow model with the Populus to Ben Lomond project now included. The load and system losses for the portion of the system between Populus and Terminal were calculated for that hour resulting in Load + System Losses= 1289.9 MW. The loads in the models were held constant.

The difference between the two study results 1300.7 MW – 1289.9 MW = 10.8 MW which is the resulting system loss reduction in this part of the system for that hour.

The actual system operation and transmission line loading will vary significantly over the life of the project and power flows will be higher and lower than the 700 MW in any particular hour and over a wide range of load and generation dispatch scenarios.

To review the Path C one-line diagrams, please refer to Attachment OCS 6.5.

OCS Data Request 6.7

Please provide a formula (such as $P_{loss} = P^2R/V^2$) that would apply to the current lines used for the Populus to Ben Lomond links vs. the new line. Explain why this formula could not be used to compute loss savings from the new line. If such a formula could be used, please provide the calculation of loss savings from the new line.

Response to OCS Data Request 6.7

The formula above is correct for calculation of a discrete line loss value for a specific line or sets of lines carrying a fixed power flow. It does not however provide a value of "line loss" savings. It can be used to compare one discrete line loss value to another when calculated for different power flows. This calculation was performed in the Company's Response to OCS Data Request 6.5 for a one hour period.

Case. No. PAC-E-10-07
Exhibit No. 607
Witness: Randall J. Falkenberg

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

PACIFICORP IDAHO INDUSTRIAL CUSTOMERS

Exhibit Accompanying Direct Testimony of Randall J. Falkenberg

PacifiCorp Data Responses to OPUC and ICNU
in OPUC Docket Nos. UE-216 and UE-100749

October 14, 2010

OPUC Data Request 22

The Company has stated that it is including the inter-hour wind integration costs for its two projects in the BPA control area. (PPL(TAM)/100, Duvall/17, Lines 11-14)

a) If BPA is not required to provide the inter-hour wind integration services for PacifiCorp's facilities located in its control area, why is the Company including inter-hour wind integration services for those facilities located in its control area, e.g. Long Hollow?

b) Using PacifiCorp's logic, wouldn't those facilities located in its control area, of which PacifiCorp is not the contracted recipient, have to provide there own inter-hour wind integration?

Response to OPUC Data Request 22

a) The Company does not incur day-ahead or hour-ahead (inter-hour) costs for wind facilities located in its control area if the output of the plant is not included in the Company's resource portfolio.

b) Yes.

ICNU Data Request 2.5

Refer to the Naughton 3 outage starting on May 26, 2009. Was this event one that resulted in a liquidated damages payment? If so, please explain whether the various outage and deration events starting on May 26, 2009 through June 2, 2009 were also consequence of the original event.

Response to ICNU Data Request 2.5

Please refer to the Company's response to ICNU Data Request 2.3, specifically Confidential Attachment ICNU 2.3. The overhaul outage was contracted with Siemens to be completed on April 25, 2009. As the turbine / generator was released to PacifiCorp for operations on May 26, 2009, liquidated damages were recovered. The outage and duration events from May 26 through June 2 were not a consequence of the original event, but would be considered normal procedures completed subsequent to an overhaul.

ICNU Data Request 10.3

Please refer to Attachment ICNU 1.33, tab "Conf". Please identify all transactions in the test year that rely upon this contract for delivery of power into the PACW as represented in the WCA model.

Response to ICNU Data Request 10.3

Please refer to the Company's response to ICNU Data Request 10.1. Purchases at the Nevada-Oregon Border (NOB) have relatively high prices, so they are one of the last options used to serve the Company's retail loads. Since this capability is unlikely to be used under the normalized circumstances contained in the Company's WCA GRID model, no purchases are modeled at NOB during the test year.

PREPARER: Hui Shu

SPONSOR: Gregory N. Duvall

Case. No. PAC-E-10-07
Exhibit No. 608
Witness: Randall J. Falkenberg

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

PACIFICORP IDAHO INDUSTRIAL CUSTOMERS

Exhibit Accompanying Direct Testimony of Randall J. Falkenberg

REDACTED VERSION

PacifiCorp Data Responses to ICNU
in WUTC Docket No. UE-100749

October 14, 2010

ICNU Data Request 1.33

For each of the Firm Transmission contracts whose costs are included in GRID, please identify the purpose of the transaction, why it is used and useful in the Test Year, the amount of capacity or type of transmission service it provides, and where the capacity or service provided by this contract is modeled in GRID.

Response to ICNU Data Request 1.33

Please refer to Confidential Attachment ICNU 1.33. The second tab in the attachment is considered non-public information and cannot be shared with PacifiCorp marketing affiliate employees. This information is confidential and is provided subject to the terms and conditions of the protective order in this proceeding

PREPARER: Hui Shu / Jim Portouw / Ken Houston

SPONSOR: Gregory N. Duvall

Confidential Attachment ICNU 1.33

[redacted]

Confidential Attachment ICNU 1.33

[redacted]

WA UE-100749
ICNU 1.33

Attach ICNU 1.33 CONF (CONF)

PacifiCorp Idaho Industrial Customers
Exhibit No. 608 Page 4 of 9
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[redacted]

PacifiCorp Idaho Industrial Customers
Exhibit No. 608 Page 5 of 9
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[redacted]

ICNU Data Request 2.3

Were liquidated damages payments made relative to any outages at any power plants which PacifiCorp has an ownership interest during the 4 year period? If so, explain the reasons for the payments, the amount and provide all relevant supporting documentation.

Response to ICNU Data Request 2.3

Yes. Please refer to Confidential Attachment ICNU 2.3 for information on liquidated damages paid relating to boiler outages at the Jim Bridger Plant and a turbine overhaul at the Naughton plant. Confidential information is provided subject to the terms and conditions of the protective order in this proceeding.

[redacted]

[redacted]

PacifiCorp Idaho Industrial Customers
Exhibit No. 608 Page 7 of 9
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Invoice

[redacted]

[redacted]

[redacted]

[redacted]

Case. No. PAC-E-10-07
Exhibit No. 609
Witness: Randall J. Falkenberg

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

PACIFICORP IDAHO INDUSTRIAL CUSTOMERS

Exhibit Accompanying Direct Testimony of Randall J. Falkenberg

**Net Power Cost Workpapers and Supporting Documents,
Attachment to Settlement Stipulation to Order 9
in WUTC Docket No. 090205**

October 14, 2010

Net Power Costs Workpapers and Supporting Documents
Agreement Between PacifiCorp and ICNU

Net Power Costs study workpapers are defined as those documents which show the source, calculations and details supporting the testimony and other exhibits including the documents used to develop the final inputs to GRID and the final modeling in GRID on the west control area basis. The data relied upon to support the cost details in the filing may include contracts, emails, white papers, studies, PacifiCorp computer programs, Excel spreadsheets, Word documents or pdf and text files.

In cases where systems change or are replaced in the future, PacifiCorp will continue to provide substantially the same information as provided in data request responses in PacifiCorp's 2009 General Rate Case as long as these filing requirements remain operative.

PacifiCorp and ICNU agree to continue the current practice of providing all discovery response answers, workpapers, including any other documents produced pursuant to this agreement via email (for non-confidential documents) and overnight mail (for confidential documents). All attachments provided through discovery that involves calculations will be provided electronically and in the case of Excel spreadsheets with all cells and formulas intact.

If there are any special circumstances where the Company has not provided documents or information within the workpapers listed below because it believes special handling procedures are necessary for that information, the Company will either:

a. Redact the information from the document indicating where such information has been redacted.
b. Identify the document(s) not provided, and provide the name of the appropriate person for ICNU to contact regarding access to the document(s).

A. **Initial Filing by the Company**
PacifiCorp will provide ICNU with workpapers and supporting documents as described below.

1. Concurrent with the Initial Study:

   a) Workpapers that show the source and calculations pertaining to the Company Net Power Cost Study(s). The workpapers will include, at a minimum, copies of the net power cost report in Excel and the net power cost model database. Access to the power cost model will also be provided.

   b) Identification of the "Time Period" used to determine outage rates and other input items in the net power cost model.

c) A list and explanation of all modeling or logic changes or enhancements to the net power cost model that have been implemented since the last Washington case in which the Company proposed to change net power costs. This will include a statement of the direction and amount of change in net power costs resulting from each such change and documentation describing each change as well as net power cost model runs and workpapers quantifying the impacts of these changes.

2. Within five business days, after the Initial Filing, the Company will deliver to ICNU the following:

a) Workpapers showing the computation of the outage rates (planned and unplanned) used in the power cost model. Include all backup data showing each outage (planned or unplanned, etc.) and duration (planned or unplanned) considered in the time period, including NERC cause code, type of event, duration, energy lost, etc. Reference: ICNU 1.6[1]

b) The heat rate curves for each resource and the spreadsheets showing the derivation of the heat rate curves. Reference: ICNU 1.26

c) Workpapers and documentation supporting the inputs contained in the "Other Cost" file used in the power cost model, including all electronic spreadsheets used to compute any of the line items in the file. This includes test year wheeling expenses modeled in GRID. Reference: ICNU 1.36

d) Workpapers and documentation supporting the "Energy Cost" file used in the power cost model, including all electronic spreadsheets used to compute any of the line items in the file. Reference: ICNU 1.57

e) Workpapers and documentation supporting the "Demand" file used in the power cost model, including all electronic spreadsheets used to compute any of the line items in the file. Reference: ICNU 1.58

3. As soon as practical, but no later than 15 days after the Initial Study has been provided, the Company will deliver to ICNU:

a) All documents, workpapers or other information relied upon by the Company in determining the market caps used in the power cost model for the forecast test period. Reference: ICNU 1.2

b) The current topology maps in the power cost model along with an explanation for all the differences that have been made to the topology since the last Washington case in which the Company proposed to change

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[1] Unless otherwise noted, all References are from discovery in UE-090205.

net power costs and an explanation of why the changes were made. Include supporting documentation, such as contracts resulting in changes to the transfer capabilities used in GRID. Reference: ICNU 1.3

c) The date and a copy of the forward price curve, showing monthly heavy load hour and light load hour forward prices, used in creating the test year power cost model studies. Reference: ICNU 1.8

d) Documents showing all short-term firm transactions (including short-term firm indexed transactions and swaps) modeled in the test year power cost study. In addition, each contract will have a designation as to its purpose (i.e., trading, arbitrage or balancing.) Reference: ICNU 1.10

e) For all power, fuel and transmission related contracts modeled in GRID that were not included in the last Washington case in which the Company proposed to change net power costs:
   1. A copy of the contract (in pdf or electronic format, if available). Reference: ICNU.1.11
   2. Any workpapers or other documents used to develop the power cost model input assumptions related to the contract. id

f) Regulatory Fuel Budget and any other workpapers used in developing the power cost model fuel cost inputs. Reference: ICNU 1.59

g) Workpapers and documentation supporting the "Demand Cost" file used in the power cost model, including all electronic spreadsheets used to compute any of the line items in the file. Reference: ICNU 1.60

h) Identification of each instance in which the Company changed any maximum capacities, minimum up or down times or unit minimum capacities for thermal or hydro generators modeled in the power cost model since the last Washington case in which the Company proposed to change net power costs. Reference: ICNU 1.61

i) Workpapers explaining the development of each line of load adjustments presented on the Company's power cost model output reports. Reference: ICNU 1.62

j) Workpapers for any screens applied to prevent uneconomic commitment and dispatch of resources in the GRID model. Reference: ICNU 1.64

k) Workpapers and all supporting documents underlying the start-up fuel costs included in GRID in the line labeled Other Fixed Costs, or the equivalent.

B. Rebuttal Filing (and sur-surrebuttal Filing, if applicable) by Company
The Company will provide workpapers and supporting documents to ICNU as described below:

1. Concurrent with Company rebuttal or sur-surrebuttal filings:

   a) Workpapers that show the source, calculations and details supporting the testimony and other exhibits. The workpapers will include the net power cost report on an adjustment-by-adjustment basis. The workpapers will include, at a minimum, electronic copies of the net power cost report and the net power cost model.
   b) For any update, adjustment or correction to the power cost model, the Company will include a description of the change and a calculation of the adjustment amount.

2. As soon as practical, but no later than five business days after filing rebuttal or sur-surrebuttal:

   a) To the extent that any of the items in Section A change, new versions of the supporting documentation and workpapers will be provided.
   b) Access to the updated runs in power cost model via the designated internet access or power cost model input files containing all inputs and output reports associated with the update filings.

C. Filings by ICNU
Testimony filed by ICNU in response to the Company's net power costs calculations will provide workpapers and supporting documents as described below:

1. Concurrent with the filing of ICNU testimony:

   a) Workpapers that show the source, calculations and details supporting the testimony and other exhibits. The workpapers will show on an adjustment-by-adjustment basis, the power cost model input file or files used, the back-up to the input files, and the power cost model study reports or documents showing the impact of the adjustment on NPC as compared to the comparison scenario. The associated power cost model input files will also be provided.