Exhibit No.___ (RJF-1T)
Docket No. UE-100749
Witness: Randall J. Falkenberg

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION,	)	
Complainant,	)	Docket No. UE-100749
v.	)	
PACIFICORP d/b/a PACIFIC POWER & LIGHT COMPANY,	)	
Respondent.	)	

RESPONSIVE TESTIMONY OF RANDALL J. FALKENBERG

ON BEHALF OF

THE INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

REDACTED VERSION

October 5, 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 Industrial Customers of Northwest Utilities ("ICNU"). My qualifications are in Exhibit No.___ (RJF-2).

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 electric restructuring, system planning, load forecasting, 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 West Control Area ("WCA") jurisdictional cost allocation model and the GRID study of normalized net power costs ("NPC") for the March 31, 2012 test period. I identify certain problems in the WCA GRID model that overstate PacifiCorp's (or "the Company") proposed Washington revenue requirements. I also address related issues concerning combined cycle plant Operations & Maintenance ("O&M"), and revenue from sales of Renewable Energy Credits ("RECs").

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. I have identified and quantified adjustments to the Company's WCA 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.

Table 1
Summary of Recommended Adjustments - $ Preliminary

	Total West Control Area		Est. WA Jurisdiction
		CAEW	22.27%
		CAGW	22.09%
I. GRID (Net Variable Power Cost Issues)			
PacifiCorp Request NPC	569,914,100.82		128,870,625.00
A. GRID Sales Margins			
1 Added Sales Margins	(2,641,596.41)		(585,874.38)
B. GRID Commitment Logic Error and Start Up Costs			
2 Commitment Logic Screens	(4,388,595.37)		(973,337.79)
C. Long Term Contract Modling			
3 East Market Sale - Corrections and Expansion	(1,015,601.10)		(225,248.14)
4 East Market Sale - Reliability Benefits	(1,249,212.07)		(277,060.25)
5 SCL Stateline Termination /Renegotiation	(3,958,799.80)		(878,014.29)
6 SMUD Contract Delivery Pattern	(2,067,393.41)		(458,523.05)
D. Transmission Modeling			
7 Colstrip East Trans. Cost	(206,009.85)		(45,690.51)
8 PACE Trans. Cost	(1,641,156.00)		(363,988.71)
9 DC Intertie Costs	(4,766,400.00)		(1,057,130.32)
10 NF Trans	(719,499.83)		(159,576.43)
E. Wind Integration Adjustments			
11 Model Wind Intra Hour Wind Integration Cost in GRID	(563,211.12)		(124,913.47)
12 Non-Owned Inter Hour Wind	(1,428,815.49)		(316,894.13)
13 Non-SCL Stateline Intra Hour Wind Integration	(289,015.53)		(64,100.18)
14 Oregon Wind Farm Intra Hour Wind Integration	(833,682.70)		(184,900.82)
15 Cambell Wind Farm Intra Hour Wind Integration	(1,161,496.55)		(257,606.00)
F. Outage Modeling and Other NPC Adjustments			
16 Planned Outage Schedule	(1,937,493.53)		(429,712.82)
17 Colstrip Outage	(1,697,532.79)		(376,492.40)
18 JBFuel Adjustments	(2,935,047.00)		(650,958.20)
19 Minimum Loading and Deration Adj.	(1,352,178.81)		(299,897.03)
20 Forward Price Curve Update	(3,457,535.40)		(766,839.86)
21 Balancing Adjustment -est.	1,000,000.00		221,788.00
Subtotal NPC Baseline Adjustments -	(37,310,272.75)		(8,274,970.77)
Allowed - Final GRID Result*	532,603,828.07		120,595,654.23
G. Other Adjustments			
22 Combined Cycle O&M Adjustment	(2,530,000.00)		(561,123.64)
23 Renewable Energy Credit Revenue	-		(4,870,266.34)
Total Adjustments	(39,840,273)		(13,706,360.75)

Conclusions and Recommendations

PacifiCorp's requested 2010 WCA NPC of $570 million (total WCA) in NPC is overstated by at least $37 million. My corrections result in a reduction to Washington jurisdictional NPC of $8.3 million. I also recommend additional reductions of $5.4 million to Washington allocation revenue requirements. I will also review any power cost adjustments proposed by other parties in their response testimony, and I may address these issues in cross-answering testimony.

A. GRID Sales Margins

<u>Adjustment 1.</u> The use of a far forward future test year precludes full inclusion of margins the Company earns on arbitrage sales within PacifiCorp's western system ("PACW"). I recommend imputation of additional margins to address this shortcoming.

B. GRID Commitment Logic Error and Start Up Costs

<u>Adjustment 2.</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, and fails to eliminate all of the error induced costs. I propose a more effective correction to this problem.

C. Long Term Contract Modeling

<u>Adjustments 3 and 4.</u> The Company's modeling of the eastern market sales contains significant errors and omissions. The Company models on peak sales only, excluding purchases and off-peak sales. Further the Company models uneconomical sales that occur when PACW resources are used to alleviate PacifiCorp's eastern system ("PACE") imbalances. My adjustments address these problems.

<u>Adjustment 5.</u> The termination of the Seattle City Light ("SCL") contract results in a mismatch between energy generation and delivery under the contract. I propose of pro-forma adjustment to remove the impact of this unrepresentative situation from the test year.

<u>Adjustment 6.</u> The Company incorrectly models the Sacramento Municipal Utility District ("SMUD") sales contracts by assuming the counterparty will take power only during the highest cost months. Actual contract delivery patterns show the contract should be modeled with a much lower cost delivery pattern. Further, the Company overstates SMUD purchases in the test year.

D. Transmission Modeling

Adjustments 7 and 8. **The Company has included certain PACE transmission costs in the WCA model. They over allocate Colstrip transmission costs to PACW, and include costs of providing dynamic reserves to PACE from PACW resources. I recommend removal of these costs.**

Adjustment 9. **The primary use of the DC Intertie is to import power from the Nevada Oregon Border to the PacifiCorp system. However, the Company includes no such transactions in the test year. I recommend removal of intertie costs to match costs and benefits in the test year.**

Adjustment 10. **I recommend inclusion of non-firm transmission links in the WCA model as these resources are used on a routine basis by the Company.**

E. Wind Integration Adjustments

Adjustment 11. **The company overstates the cost of wind integration because it assumes reserve requirements due to load and wind are additive. However, because there is no correlation between load and wind, their combined reserve requirements are much lower than the sum of their individual requirements. This adjustment also incorporates the wind integration modeling into the WCA model rather than using the Company's simplistic and error ridden spreadsheet model. Both of these adjustments are consistent with the Company's September 2010 wind integration study design.**

Adjustments 12-15. **The Company includes various costs related to integration of non-owned or non-WCA model wind resources. These costs should be excluded because the Company is not compensated for providing these integration services and/or they should not be included in the WCA model in the first place.**

ICNU objects to the Company's proposal to update the wind integration costs based on its 2010 Integrated Resource Plan ("IRP") wind integration study. Given the complexity of the study and the lateness of its completion there is insufficient time in this proceeding to review the new study.

F. Outage Modeling Adjustments

<u>Adjustment 16.</u> The planned outage schedule used by the Company in GRID places outages in higher cost periods than necessary and the schedule is not aligned with actual practices.

<u>Adjustment 17.</u> This adjustment caps an exceptionally long outage of Colstrip 4 at 28 days in the four-year average outage rate calculation. This is consistent with the Company's testimony in a recent Oregon rate case. It is unrealistic to assume such an extreme event will occur once every four years. Making this adjustment will increase the accuracy of the Colstrip outage rate forecast during the rate effective period.

<u>Adjustment 18.</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 19.</u> GRID fails to properly account for the impact of forced outage rates on unit minimum capacities and heat rates. This adjustment invokes an industry standard modeling method, already used by the Company for fractionally owned units.

<u>Adjustment 20.</u> This adjustment reflects an update to a more recent forward price curves consistent with the Washington Utilities & Transportation Commission's ("WUTC" or the "Commission") practice. I exclude an adjustment related to Chehalis reserve capability, and certain non-WCA transmission costs.

<u>Adjustment 21.</u> This is a placeholder for the balancing effect of all other adjustments. The final impact of balancing can only be computed using all WUTC approved adjustments.

G. Other Issues

<u>Adjustment 22.</u> My proposed screening adjustment reduces the number of starts of combined cycle plants in the test year, overstating O&M costs.

<u>Adjustment 23.</u> The Company's reverses $4.2 million in 2009 actual green tag revenues out of the test year on the basis it will sell no RECs after the Renewable Portfolio Standard ("RPS") goes into effect. This is unreasonable because the Company

will have ample Washington allocated RECs available for sale even after the RPS goes into effect. Based on the Company's current projection of REC prices, revenues in excess of 2009 actual levels should occur during the rate effective period.

A. GRID TRANSACTION MARGINS

Q. THE COMPANY IS USING A TEST YEAR ENDING MARCH 31, 2012 FOR NPC PURPOSES IN THIS CASE. DOES THIS POSE ANY SPECIAL PROBLEMS THAT NEED TO BE ADDRESSED?

A. Yes. This filing uses a forecast period more advanced into the future than in any of the Company's recent cases. In preparing its future test year, the Company is limited to including only the wholesale transactions of which it is aware at the time of the filing. This creates a problem because short-term firm sales ("STF") sales produce additional margins that will offset power costs. However, in many cases these transactions are not completed until much closer in time to their closing. Indeed, in many cases, the transactions are determined on a day ahead basis. In a fully historical test year, the Company could include all STF transactions, and the test year would more fairly reflect all costs and revenues. In this case, however, there are very few STF transactions modeled, thus, little opportunity to include profits made by the Company on a routine basis. There are three types of transactions that should be considered in establishing a proper test year: 1) balancing; 2) arbitrage; and 3) trading.

Q. ARE THERE OTHER PROBLEMS THAT ACCOMPANY USE OF A TEST YEAR THAT IS ADVANCED FAR INTO THE FUTURE?

A. Certainly. Another problem is the matter of matching costs and revenues. In this case, the Company has computed its transmission costs based on historical data with pro-forma adjustments. Because transmission costs are fairly stable over time this should provide for accurate forecasts. These expenditures enable the

Company to move power about the system in order to minimize cost. They also enable the Company to make purchases and sales of power in real time. However, the wholesale prices for power are not nearly as stable as transmission costs and historical data is of limited use in forecasting future transactions, many of which are not even arranged until shortly before receipt or delivery of power. This poses a serious problem because many of the benefits created by the transmissions costs (and other expenditures) are, therefore, excluded from the test year. Consequently, adjustments may be needed in the test year to properly match costs and revenues and other benefits associated with costs.

Q. CAN YOU PROVIDE A HYPOTHETICAL EXAMPLE?

A. Yes. Imagine two transmission areas, A and B, with hourly prices P_A and P_B and that PacifiCorp has a transmission contract that allows it to move power between the areas. If $P_A > P_B$ during a period of time, PacifiCorp could buy power in A and sell it in B. If the reverse were true the Company could move power in the opposite direction. Because the differential between market prices is somewhat predictable, the Company can make STF purchases and sales to take advantage of these situations. In fact, the Company expects these situations to occur, so it has already arranged the transmission contracts for future periods. However, the actual realization of the additional revenue does not occur until shortly before the trading takes place. As a result, a test year constructed in the manner used by the Company will include the transmission costs associated with short term activities, but not all of the associated revenues.

Q. EXPLAIN THE DIFFERENCE BETWEEN BALANCING, ARBITRAGE AND TRADING AS REGARDS SHORT-TERM FIRM TRANSACTIONS.

A. The Company constantly engages in STF transactions to effectuate a more optimal balancing of the system. The goal of balancing is to match supply and demand and minimize costs, but not necessarily to make profits on transactions. In GRID, balancing is accomplished via the use of secondary transactions, which are priced at the same level (on average) as the conventional STF transactions. Consequently, balancing is addressed by the GRID model. However, in some cases, if there is a substantial imbalance at the time of the filing, emergency energy purchases or "dump sales" could show up in GRID. My review of the test year indicates that this problem is not a serious one, for this test year, although it was a problem in prior cases.

Arbitrage occurs when the Company is able to take advantage of price differences between counterparties. Profit generation is the goal of arbitrage and when the right opportunities are present, it is low risk endeavor.

Trading is when the Company takes a position (long or short) at one price, and then closes that position later at a (hopefully) better price. The goal of trading is also to generate profits; however, it involves an element of risk because expected price changes may or may not occur. Typically, the vast majority of the of the Company's short term transactions were related to balancing and the remainder are for arbitrage or trading purposes.

While the goal of trading is to generate profits, it is not typically a large profit center and it is a risky activity. Over time, it appears that trading profits are sporadic at best, and sometimes losses occur. This was the case for the 2006-

2009 four year period. However, the historical data shows a mismatch between the long and short positions taken by the Company. When this mismatch is corrected, there were trading profits in the four year period. However, such an adjustment is speculative. Consequently, I ignore trading profits in my adjustment. Instead, I recommend that the Company be allowed to retain trading profits while absorbing any associated losses.

Q. HAS THE COMPANY INCLUDED ANY ARBITRAGE OR TRADING PROFTS IN GRID STF TRANSACTIONS?

A. The Company has not included any arbitrage and trading profits in the STF transactions it modeled in GRID. In fact, all of the STF contracts included in GRID are for balancing purposes. This is due to the fact that the test year is so far advanced into the future, that the Company has very few contracts of any type arranged at this time.

Q. DOES GRID MODEL ARBITRAGE ON SPOT TRANSACTIONS?

A. The Company has asserted GRID does so.[1/] However, it has stated it cannot quantify the amount of these transactions.[2/] Further, off-peak arbitrage transactions are severely limited by use of market caps in the model.

Q. HOW SHOULD GRID RESULTS BE MODIFIED TO REFLECT STF ARBITRAGE PROFITS?

A. I recommend imputation of the four-year average for STF arbitrage profits. Over the four-year period 2006-2009, the Company's arbitrage profits averaged approximately $2.6 million. Confidential Exhibit No.___ (RJF-3C) shows the

1/ Exhibit No. __ (RJF-5) at 6 (Response to DR ICNU 4.22, WUTC Docket No. UE-080220).
2/ Exhibit No. __ (RJF-5) at 7 (Response to DR ICNU 4.23, WUTC Docket No. UE-080220).

development of this adjustment based on the response to ICNU DR 1.3. The impact of this adjustment is shown on Table 1 of the above-mentioned exhibit.

Q. HAVE OTHER COMMISSIONS ADOPTED THIS TYPE OF ADJUSTMENT?

A. Yes. In a recent Oregon Public Utility Commission ("OPUC") case (UE 191) the OPUC stated:

> Thus, we accept Staff's premise that the GRID model systematically understates the extent of Pacific Power's wholesale market activities. From that premise Staff infers that Pacific Power receives a systematic positive return on its net short-term wholesale transactions that are not included in the GRID runs. Staff attributes that return to Pacific Power's ability to leverage the flexibility of its diversified system.
>
> * * *
>
> The remaining 13 percent of Pacific Power's short-term wholesale transactions are properly attributed to Pacific Power's arbitrage and wholesale trading activities. The Company calculated that the Oregon allocated margins on such activities averaged $0.8 million annually (from 2003 through 2006). There is no evidence that those results are included in the GRID model results. However, we conclude that such revenues are properly considered in the calculation of NVPC and the model results should be adjusted as necessary to incorporate those revenues.[3/]

Note that the figure quoted, $0.8 million was an Oregon jurisdictional number. The Washington number for this case is on Table 1.

B. GRID COMMITMENT LOGIC ERROR

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

[3/] Re PacifiCorp's 2008 Transition Adjustment Mechanism, OPUC Docket No. UE 191, Order 07-446 at 10-11 (Oct. 17, 2007).

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

A. Yes. Mr. Duvall has included a daily "screening adjustment," which is intended to correct this problem. 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 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 accepted by regulators in prior litigated cases.

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 is not the path to the optimal solution. Indeed, it can make finding the best solution impossible. However, solving this problem requires almost no additional work or additional steps in the process. All that is required is to place the cycling units 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

Chehalis. This limits the number of start-up/shut down choices. For example, a 10 PM shutdown of 8, 9, or 10 hours is considered, but not a longer and more accurate shutdown period. Consequently, one problem is the inflexibility of the Company approach.

Another problem with the Company's methodology is that it fails to address the circumstances specific to the Hermiston plant, and the costing methods used in its gas contract, as well as the Hermiston purchase contract. If Hermiston gas requirements decline (due to use of a screen), the average contract price increases. Further, there is a variable O&M component in the Hermiston purchase contract. Unless the actual costs of Hermiston are considered, the Company's screens will prove to be inaccurate and result in many unnecessary starts and stops.

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.[4/] 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.[5/] The method also will allow a single screen to run for days or weeks in succession if that is the optimal choice. It also

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

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

does not produce as large a number of unused screens as the Company's method. This results in a smaller database and may reduce the possibility of error. Finally, the screening method specific to Hermiston is used, which addresses the unique costing mechanisms in place for this resource.

Q. EXPLAIN THE ADJUSTMENTS YOU COMPUTED IN TABLE 1.

A. In Table 1, I estimate the effect of implementing more optimal screens for Hermiston and Chehalis. 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-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 22, while the fuel cost impacts are included in Adjustment 2.

Q. ARE YOU PRESENTING THE FINAL SCREENS THAT SHOULD BE USED IN THIS AND FUTURE CASES?

A. No. The final screens will depend on the adjustments adopted by the Commission and, more importantly, on the final forward price curves used. I understand the WUTC has allowed certain updates for gas prices in the past. If an update is allowed in this case, a different set of screens should be used. Consequently, I am presenting the screen adjustment in Table 1 to provide a reasonable estimate of the impact of using better screens, and recommend the Commission require the Company to implement all Commission approved adjustments based on the methodology I am proposing. While I believe the results shown on Table 1 will be indicative of the final results, the final screens can only be determined after all Commission approved adjustments are identified.

C. 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. As part of the WCA model, the Company also models a sale to the eastern markets (i.e., PACE) to utilize excess generation, and take advantage of price differences between Mid C and the eastern markets. I will discuss issues related to certain of PacifiCorp's contracts and sales modeling in GRID.

Adjustments 3 and 4. Eastern Market Modeling

Q. HAVE YOU EXAMINED THE COMPANY'S MODELING OF THE EASTERN MARKET SALE IN THE WCA MODEL?

A. Yes. The Company provided supporting workpapers as part of its GRID support documents pursuant to the Stipulation in WUTC Docket No. UE-090205.

Q. PLEASE EXPLAIN WHAT THE COMPANY'S EASTERN MARKET MODELING REPRESENTS.

A. The Company modeling represents a partial determination of benefits that result from transacting energy between the western and eastern markets. The Company introduced this methodology in the rebuttal phase of UE-061546. Company witness, Mr. Mark Widmer described the modeling in terms of hourly pricing of transactions.[6/] These transactions really represent cross control area transactions that were intended to capture hourly price differences, as Mr. Widmer discussed.

[6/] "The price of the sale is equal to the Mid-C hourly price plus a share of the margin." WUTC v. PacifiCorp, WUTC Docket Nos. UE-061546 and UE-060817, Rebuttal Testimony of Mark T. Widmer, Exhibit No. MTW-8T at 3 (March 5, 2007) (internal citations omitted).

Q. DID THE COMMISSION AND STAFF ALSO ENDORSE THESE CONCEPTS FOR MODELING OF EASTERN MARKETS IN THE WCA MODEL?

A. Yes, based on the Commission's discussion of the issue in the final order in Docket UE-061546. In Order No. 08, the Commission stated:

> Staff contends that the WCA methodology "reflects a common sense application of the used and useful standard" because:
>
> - It is based on the resources used to support the west control area, which includes Washington.
> - It allows for direct assignment of resources outside the west control area if transmission capacity to the west control area exists.
> - *It allows for indirect inclusion of eastside benefits and costs if purchases or sales between the control areas are economic.*[7]

In paragraphs 57 and 58 of Order No. 08, the Commission adopted the proposed adjustment for the eastern market modeling.

Q. DOES THE GRID MODELING OF THE EASTERN MARKET ACHIEVE THESE GOALS?

A. No. The eastern market modeling used by the Company has not fulfilled the expectations discussed above. First, the Company models only sales from the west to the east control area, not purchases, as discussed in the Commission's order above. Second, while the Company uses hourly data to derive inputs for the modeling of the transaction it does not properly consider hourly price difference, nor does it perform a realistic test to determine whether sales are economical. Finally, the Company models only on-peak sales, ignoring opportunities for off-peak transactions that frequently exist. Nothing in the Commission's order in

[7] WUTC v. PacifiCorp, WUTC Docket Nos. UE-061546 and UE-060817, Order No. 08, ¶ 47 (June 21, 2007) (emphasis added).

Docket UE-061546 suggested the Commission intended to limit this modeling to on peak hours only, or to only allow the transactions to flow from west to east.

Q. CAN YOU DESCRIBE THE MECHANICS OF THE COMPANY'S MODELING?

A. The process used by the Company requires a modeling of the entire PacifiCorp system. This is necessary because the Company uses the hourly transmission transfers from the GRID simulation of the entire system to determine the amounts of energy sold in the eastern market sale used in the WCA model. To analyze this modeling, I obtained the GRID system database the Company used for this analysis from the response to ICNU DR 1.22.

Q. EXPLAIN THE STEPS PERFORMED IN THE COMPANY MODELING.

A. In the system level simulation GRID determines for each hour the transfers between the eastern and western control areas, through various transmission paths. Those modeled in the eastern market sales travel across certain links: Idaho to Goshen, Idaho to Path C, Idaho to Path C North, Idaho to Path C STF, and Jim Bridger to Wyoming Central. Each hour GRID determined the flow of energy from west to east (or vice-versa) based on loads, generation, constraints and market price differences. If there is a market price difference between east and west in a given hour, GRID will make a trade between markets up to the maximum amount allowed by transmission constraints. As it was recognized that the PACW often has lower prices than PACE, this was intended to reflect some of the benefits the western part of the system provides to the integrated system. In effect, the eastern market modeling is intended to reflect some of the benefits of integration of the system as a whole.

Q. HOW IS THIS DATA USED IN THE WCA MODEL?

A. The inputs for the eastern market sale are created by producing monthly averages of the hourly transaction and pricing data for on-peak PACW to PACE transfers. Further, it is assumed that the PACW will only obtain 40% of the margins and 60% of the volumes of the transactions.

Q. WHAT IS THE BASIS FOR THE 40% AND 60% SPLITS DISCUSSED ABOVE?

A. They are essentially arbitrary. The only justification provided for either was some subjective comments offered in Mr. Widmer's rebuttal testimony in Docket UE-061546.[8/] For example, the 60% reduction to transactions volumes was based on the assumption that there would be competition for sales to PACE. However, given the way in which the volumes were developed (from a system level GRID run) such an assumption was simply baseless.

Q. DOES THE COMPANY CARRY OUT THIS MODELING ON AN HOURLY BASIS FOR THE EASTERN MARKET SALE?

A. No, although it would take little more effort than the Company's current modeling. Instead, the Company models a monthly average sale during the Heavy Load Hours ("HLH"). As a result, the Company ignores potential sales during Light Load Hours ("LLH") and introduces certain problems into the modeling of the eastern market sale. For example, the Company ignores some times when sales might be made profitably, and includes other times when the sales are not profitable. Further, the Company does not consider the possibility of purchases by PACW from PACE. All three of these problems run counter to the

[8/] WUTC v. PacifiCorp, WUTC Docket Nos. UE-061546 and UE-060817, Rebuttal Testimony of Mark Widmer, Exhibit MTW-8T at 3-5 (March 5, 2007).

Commission's original expectations - inclusion of <u>economic purchases and sales</u> between control areas.

Instead, the Company's approach only allows for a portion of the economic sales, and introduces many uneconomic sales into the WCA model simulation. In fact, 25% of the sales modeled on an hourly basis are uneconomic, thus reducing the benefit of the eastern market sale modeling, and actually increasing NPC.

Q. DO YOU KNOW WHY THE EASTERN MARKET SALE PRODUCES UNECONOMIC TRANSACTIONS IN THE WCA MODEL?

A. There are three reasons. First, the WCA model uses a monthly average price, rather than an hourly price. As a result, there may be hours when the averaged price is below the hourly price used in GRID. Consequently, such hours will make the transactions, but at a loss. Second, the eastern market sale is priced below the actual market price in the east. This is because the WCA model is only credited with 40% of the margin between PACE and PACW market prices. Consequently, there may be hours when the sales are uneconomic at the prices assumed in the WCA model, but would be economic if the PACW was paid the actual market price in the PACE. In the system level run, transfers may be made whenever there is a difference in price between the control areas. However, the direction may actually be the opposite of that assumed by the Company.

Finally, in many cases the transfers from PACW to PACE are being made for <u>reliability</u> rather than economic purposes. In fact, the Goshen transmission area would experience numerous imbalances (shortages of energy on an hourly basis) absent tie line support from the PACW. In GRID it is such imbalances are priced at 125% of the market price, so it is clear that the benefit the PACW provides the PACE in terms of avoiding imbalances is substantial. However, when these transfers are included in the WCA model along with the economic transactions, the result is a penalty whenever the PACW for provides capacity for reliability purposes to the east. This hardly seems equitable or reasonable.

Q. HOW HAVE YOU ADDRESSED THIS ISSUE?

A. I analyzed the hourly power transfers and market prices used to compute the eastern market sale modeling in GRID. I used the same data and methodology as the Company, but performed the analysis on an hourly basis. The Company's modeling was based on monthly average, while I used the same logic and assumptions but modeled the transactions on an hourly basis. I also included off-peak hours in my modeling. The hourly modeling helps to avoid the first two problems discussed above, because it eliminates the uneconomic transactions.

Q. DID YOU ALSO MODEL EASTERN MARKET PURCHASES?

A. Yes. There are times when purchases are also economical for PACW because during some months, prices in the west are higher than those in the east. As noted above, the expectation in Docket UE-061546 was that both sales and purchases would be considered. Including purchases as well as sales increases the benefit of the eastern market modeling by a modest amount, but should be included because it might be more significant in future cases and it is the methodology approved by the WUTC. These two adjustments are combined on Table 1 as Adjustment 3.

Q. HOW DID YOU ADDRESS THE ISSUE OF THE RELIABILITY BENEFITS OF TRANSFERS TO THE EASTERN MARKET?

A. I modified the Company's system level GRID run to remove the links from PACW supporting PACE. This resulted in a substantial increase in imbalances in the Goshen transmission area. I computed the benefit to PACE from avoiding these imbalances, based on 125% of the market price. This benefit was then split equally between PACW and PACE. This is shown as Adjustment 4 on Table 1.

Q. ARE THERE OTHER REASONS WHY THE WUTC SHOULD IMPUTE THESE ADDITIONAL BENEFITS TO THE WCA MODEL?

A. Yes. I believe that the overall goal of the WCA model was to provide Washington customers with an <u>equitable</u> allocation of system costs and benefits. The discussion above shows the Company has ignored some of the benefits of system operation. An analysis previously performed by the Company also shows that the WCA model assigns more costs to the Washington than would have been the case under the Revised Protocol methodology, used in the other states. Exhibit No.____ (RJF-4) is a copy of a study the Company presented to the Multi State Process Standing Committee comparing Washington revenue requirements under the WCA and Revised Protocol methods. It showed that under the WCA model, Washington is assigned revenue requirements approximately $1.7 million higher than under the Revised Protocol method. In part, this discrepancy exists because the allocation of the system integration benefits (discussed above in the context of the eastern market modeling) fails to provide Washington with many of the benefits the west provides the east. The adjustments I propose (adjustments 3, 4, 7 and 8 on Table 1) would restore only about half of the difference between the

WCA and Revised Protocol methodologies for Washington, and would improve the equity of these results. Other relevant information is that PacifiCorp has also provided comparisons of the average industrial rates in Washington and Utah at the time of the Utah Power & Light/Pacific Power & Light merger and the average industrial rate for Washington and Utah in 2009.[9]

Q. THE DISPARITY BETWEEN WASHINGTON RESULTS UNDER THE WCA MODEL AND THOSE UNDER THE REVISED PROTOCOL IS MUCH GREATER THAN YOUR PROPOSED ADJUSTMENTS TO THE EAST CONTROL AREA SALES MODELING. DO YOU HAVE ANY ADDITIONAL PROPOSALS TO MAKE?

A. Yes. As noted above, there is little real support for the 60% (applied to volumes) and 40% (applied to margins) parameters of the WCA model. When combined, this approach results in PACW receiving only 24% of the benefits of West to East sales. Since Washington is only 22% of the WCA, it receives only about 5% of these benefits. To address the disparity between WCA and Revised Protocol results, the Commission may wish to consider an additional alternative adjustment. As noted above, the 60% of volumes factor is unsupported and erroneous. The original (completely subjective) justification was that the volumes should be reduced to account for competition with other generators. However, the volumes in the system level GRID model assume 100% of these transactions are generated internal to the system. The system level study already models various STF transactions, as well as QFs and other long and short-term purchases which accounts for other generators in the area. Consequently, there is really no basis for the 60% of volumes assumption. As an alternative additional adjustment, I

9 See Exhibit No. __ (RJF-5) at 9 (Response to DR ICNU 17.2, WUTC Docket No. UE-100749).

recommend the Commission consider assuming 100% of volumes be included in the calculation of the Eastern Market sale. This would reduce total WCA NPC by approximately $3.5 million, and reduce Washington allocated NPC by $770 thousand. This increases and is not duplicative to the four separate WCA-related adjustments I am proposing (adjustments 3, 4, 7 and 8 on Table 1).

Q. WOULD IT TAKE SUBSTANTIALLY MORE EFFORT TO IMPLEMENT THE ADJUSTMENTS ABOVE PERMANENTLY IN THE WCA MODEL?

A. No. The underlying analysis is essentially the same as the Company's approach. It would only require use of a more detailed spreadsheet analysis to implement hourly bidirectional modeling on a permanent basis within the GRID model. The imbalance modeling could also be implemented as an additional transaction.

Adjustment 5. Seattle City Light Contract Termination

Q. PLEASE DISCUSS THE SEATTLE CITY LIGHT ("SCL") STATELINE CONTRACT.

A. Under this contract PacifiCorp provides storage and integration services to SCL. PacifiCorp takes delivery of power from the Stateline wind farm and within two months must return the energy to SCL. SCL also provides [redacted] to PacifiCorp as partial compensation for providing these services.

The SCL contract terminates during the test year. Deliveries of power end on December 31, 2011. However, the return of energy occurs until February, 2012. As a result, there is a mismatch in the test year where 11 months of energy is being returned to SCL, but only 9 months of deliveries. If the contract were renewed, or re-negotiated, it is unlikely this situation would exist. In any case, this is an anomaly, which should not be reflected in permanent rates.

Q. HOW SHOULD THE COMMISSION ADDRESS THIS ISSUE?

A. I recommend the contract be removed from the test year. This is a rather unique event and certainly not representative of future circumstances. Further, if the contract is renewed, the terms and conditions should be such that the Company is at least neutral to the arrangement. Consequently, removing the contract from the test year provides a reasonable basis for addressing this issue. This normalization is shown as Adjustment 5 on Table 1.

Q. DO YOU HAVE ANY FURTHER COMMENTS REGARDING THE SCL CONTRACT?

A. Yes. The Company receives [redacted] In all likelihood, the Company may be much better off not entering into a new contract with SCL if a compensatory arrangement cannot be negotiated.

Adjustment 6. 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 purchasers' 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 WCA 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[10/] 3504 hours[11/] 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 "highest cost" scenario.

Q. IS THIS REALISTIC?

A. No. In fact, it is highly improbable, based on historical data. Figure 1, below, compare 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

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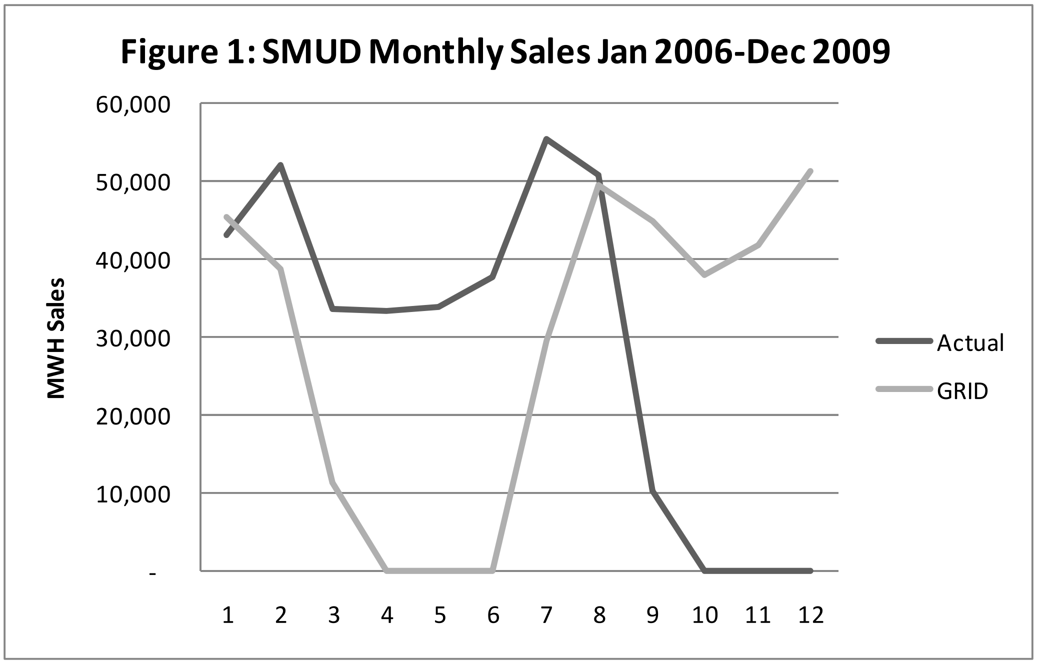
10/ Based on COB market prices.

11/ 350,400/100= 3504.

never take power during low cost months such as April through June, in reality SMUD takes substantial deliveries during those months.



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. 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 CONTRACTS?

A. Yes. The Company uses historical data to compute various inputs for the various contracts including GP Camas, small purchase contracts, and reserve requirement inputs for non-owned generation located in it 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 Public Service Commission (the "Utah Commission") accepted the adjustment.[12/] 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.[13/] 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.

12/ 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).

13/ 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 "most cost" modeling of SMUD unless abandoned the least cost modeling of Hermiston, BPA or other resources. However, the Hermiston purchase is inseparable from the Hermiston plant and cannot be dispatched differently from the rest of the plant. In the case of BPA, the Company can react to changes in prices on a day to day or even hour to hour basis. As the actual market prices that occurred in the past are unlikely to match the normalized pattern of forecast market prices, there is no basis to assume historical data should be used for BPA.

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.

Q. HAS THE COMPANY MADE OTHER ARGUMENTS CONCERNING THE MODELING OF THE SMUD CONTRACT?

A. The Company has also argued that if the SMUD shaping is modified one should begin to recognize deliveries and receipts under the provisional clause of the SMUD contract. However, the Company has never sought cost recovery of this contract option in prior cases, and has never established its prudence.

Q. PLEASE EXPLAIN THE PROVISIONAL CONTRACT CLAUSE.

A. Under this option, SMUD may take an additional 219,000 MWh at a delivery rate not to exceed 100 MW per hour, at any time it desires during any given year. SMUD then has to return that power at any time it desires the following year. There are two problems with the Company's argument concerning the provisional delivery options. First, no Commission has ever considered the prudence of the provisional contract option, though the Utah Commission was not persuaded by this argument in its most recent case, Docket No. 09-035-23.[14/] This is an extremely unfavorable aspect of the SMUD contract, which heretofore, the Company has never modeled in any of its power costs studies, in Washington, or in any other state. Indeed, the Company has never sought rate recognition of the provisional contract deliveries or receipts in Washington, or elsewhere to my knowledge. See e.g., Exhibit No.____ (RJF-5) at 1-2 (which shows a copy of a data response from Wyoming Docket 20000-266-EP-07 (WIEC DR 1.6) that states that for ratemaking purposes the Company has always excluded the provisional energy). The same exhibit also shows a copy of the GRID Long Term Contract Attributes from the 2008 Washington general rate case, which shows

[14/] Id.

that SMUD provisional energy, was excluded by the Company from its GRID study. This can be seen by noting the "Restricted" entry is equal to one at all times. This means the SMUD provisional return energy was prevented from being dispatched every single hour. To my knowledge, the same was true for every previous case.[15]

Second, to now address the provisional clause, it would be necessary to develop imputed prices reflecting a prudence determination concerning the possible high value deliveries to SMUD and the low value returns. The prudence of deliveries under that option of the SMUD contract is highly questionable, and has never been justified by the Company or considered by the Commission. The prior imputed prices used by the Commission would most certainly not be applicable because it was originally based on the Southern Cal Edison contract. SCE was a straightforward sale without the highly unfavorable exchange elements of the SMUD contract. To establish prudence, a contemporaneous exchange contract or some other method would need to be considered. As a result, I don't believe that the highly unfavorable aspects of the provisional clause can be used to justify overturning the established modeling of the SMUD contract.

Q. ARE THERE ANY OTHER PROBLEMS RELATED TO THE COMPANY'S MODELING OF THE SMUD CONTRACT?

A. Yes. The Company has included more than the actual contract energy allowed under the SMUD contract (359,900 MWH vs. 350,400). As a result, the Company has further overstated the cost to ratepayers due to the SMUD contract.

[15] The Company includes the Provisional deliveries in GRID, I believe, because it is used for other kinds of power cost studies. The budget, for example, might include these contract deliveries as it has been excluded for regulatory purposes, but would still impact actual NPC.

This problem is also corrected in Adjustment 6. By itself, this error results in additional costs in GRID of $173,597.65 (Washington's share is $38,503.96).

D. TRANSMISSION MODELING

<u>Adjustments 7 and 8. PACE Transmission Costs</u>

Q. HAS THE COMPANY INCLUDED ANY TRANSMISSION COSTS RELATED TO PROVIDING SERVICE IN PACE?

A. Yes. The Company has included half of the cost related to wheeling expense for the Colstrip plant. This follows from the Company's testimony in Docket No. UE-090205. In that case, Company witness Dr. Hui Shu testified as follows:

> [T]he Company modified its inputs of wheeling expenses in the west control area in this filing to: (1) remove half of the wheeling expense for the Colstrip plant to reflect that only Colstrip 4, half of the Colstrip plant, is authorized by the Commission for rate setting in Washington. . . .[16/]

Q. DO YOU AGREE WITH THE COMPANY'S ADJUSTMENT?

A. No. I agree that some Colstrip related wheeling costs should be removed from the WCA model. However, review of transmission topology maps for the PacifiCorp system, show that more than half of the costs related to Colstrip wheeling are attributable to providing service to PACE. Based on the topology, there is [redacted] MW of transfer capacity from Colstrip to the PacifiCorp system. Of this amount, [redacted] is attributable to connecting Colstrip to PACE, while on [redacted] MW is attributable to connection to PACW.[17/] Because the interconnections to PACE are not modeled in GRID, these costs should be excluded. As a result, I apportion [redacted] (45%) of the cost to PACE, rather than 50% as used by the Company.

16/ <u>WUTC v. PacifiCorp</u>, WUTC Docket No. UE-090205, Direct Testimony of Hui Shu, Exhibit No. HS-1T at 12 (Feb. 9, 2009).

17/ <u>See</u> Confidential Exhibit No.____ (RJF-6C) (a current system topology map).

Q. ARE THERE OTHER WHEELING COSTS NOT RELATED TO PROVIDING PACW SERVICE INCLUDED IN THE COMPANY'S MODEL?

A. Yes. [redacted] This was confirmed in Confidential Attachment to ICNU DR 9.7.[18/]

[redacted] In Docket UE-061546 the Commission rejected ICNU's proposal to include benefits from the reserve transfers between PACW and PACE in the WCA model.[19/] Given that, it is unreasonable to include costs in the WCA model which provide PACE with reserves from PACW resources. As these resources are used for both transfers to the PACE and to the PACW, I recommend splitting the cost between the control areas. One could justify a higher allocation to PACE based on the relative share of benefits between the control areas, however.[20/]

Finally, based on the responses to ICNU DR 1.33 and DR 9.5, the Company has also included costs related to providing transmission service to isolated loads in Idaho. These should be excluded from the WCA model as well. Adjustment 8 also removes these additional PACE wheeling costs from the WCA model.

18/ See Confidential Exhibit No.__ (RJF-7C) at 2-5 and 10 (Responses to ICNU DR 1.33 and 9.7).

19/ WUTC v. PacifiCorp, WUTC Docket Nos. UE-061546 and UE-060817, Final Order, ¶ 53-54 (June 21, 2007).

20/ Total system GRID runs show that the reserve transfer benefits to PACE outweigh the energy transfer benefits to PACW.

Adjustment 9. DC Intertie Costs.

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

A. [redacted]

Q. WHAT IS YOUR RECOMMENDATION?

A. This contract should be removed from the test year to match costs and benefits. The Commission has already stated that pro-forma adjustments should match costs with offsetting revenues and other items.[21/] There are no 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 projected so advanced into the future there are none that can be identified and included at this time.

[21/] WUTC v. Avista, Docket No. UE-090134, Order 10 ¶ 47 n.45 (Dec. 22, 2009). Note that the entire GRID modeling must be considered as a pro-forma adjustment to the historical test year, as it makes changes to the actual NPC in the historical period.

Further, the contract clearly does not provide a resource that is used and useful for the test year. [redacted] This provides another basis to eliminate these costs from the test year.

Adjustment 10. Non Firm Transmission

Q. HAS THE COMPANY RECENTLY CHANGED ITS TRANSMISSION MODELING IN GRID IN WASHINGTON AND OTHER STATES?

A. Yes. Starting with Utah Docket 08-035-38, the Company has included STF transmission capacity in GRID, based on 48 months of history. In most states, the Company is now including STF transmission, and has done so in the instant case as well. Although the Company has also been including non-firm transmission in GRID in Utah since Docket No. 08-035-38[22/] and recently agreed to do so in Oregon in Docket UE 216,[23/] it has not done so in this case.

Q. DO YOU ADVOCATE INCLUDING NON-FIRM TRANSMISSION IN GRID?

A. Yes. I recommend that non-firm transmission be included in GRID. These are resources available to the Company, which are used on a daily basis. This is Adjustment 10 on Table 1. The Company models non-firm purchases and sales of energy in GRID, and there is no reason not to do the same for non-firm transmission.

22/ This was required by the final order in Utah Commission Docket No. 07-035-93, which was the case prior to 08-035-38.

23/ Re PacifiCorp's 2011 Transition Adjustment Mechanism, OPUC Docket No. UE 216, Stipulation at 4 (July 6, 2010).

E. WIND INTEGRATION ADJUSTMENTS

Q. EXPLAIN THE COMPANY'S MODELING OF WIND INTEGRATION COSTS IN THE TEST YEAR.

A. Rather than modeling wind integration directly in GRID, the Company models these costs as a purely financial adjustment to the test year. The Company includes $14.4 million in wind integration costs including $3.0 million paid to BPA for integration of the Goodnoe and Leaning Juniper projects. These costs are included as part of the transmission wheeling expense. The Company includes a charge of $5.16/MWh for intra-hour wind integration costs and $1.81/MWh for inter-hour integration costs. Table 2 below shows the wind integration charges the Company includes by project.

Table 2 Wind Integration Adjustments

	MWH	Inter-Hour		Intra-Hour	
Marengo I Wind p332428	394,338	$ 713,489.37		$ 2,035,187.06	
Marengo II Wind p423463	187,890	$ 339,955.72		$ 969,703.98	
Combine Hills Wind p160595	111,751	$ 202,194.50		$ 576,748.10	
Oregon Wind Farm	161,535	***$ 292,269.81***	*	***$ 833,682.70***	*
Campbell	225,052	***$ 407,193.75***	*	***$ 1,161,496.55***	*
SCL Stateline	347,106	***$ 628,029.79***	*	***$ 1,791,418.56***	**
Stateline Non-SCL	56,000	***$ 101,322.14***	*	***$ 289,015.53***	*
Goodnoe Wind p332427	267,538	$ 484,064.42		$ 1,455,120.00	
Leaning Juniper 1 p317714	306,097	$ 553,831.47		$ 1,555,740.00	
Inter-Hour Wind Integration Cost Adjustment					
Total	2,057,306	$ 3,722,350.96		$ 10,668,112.47	
		Total		$ 14,390,463.43	
		$/MWH		$ 6.99	
		$ 1,428,815.49		***$ 4,075,613.34***	

***Recommended Disallowances**

***** SCL Disallowance based on contract termination**

Q. MR. DUVALL TESTIFIES ON PAGE 17 THAT THE COMPANY WOULD UPDATE ITS WIND INTEGRATION STUDY ON AUGUST 2, 2010. IS THIS APPROPRIATE?

A. No. First, the Company did not even complete the study until September 1, 2010. ICNU opposed the delay to September 2010, and requested that the Company complete the study on time. As of this filing date, the Company has not updated its power cost study to reflect the new charges. These studies are quite complex and often controversial. The analyses underlying these studies would likely require substantial review prior to their use in a rate case. The Company's prior wind integration studies have been subject to substantial criticism by various experts and contain numerous acknowledged errors and biases. Further the Company studies are primarily intended for long term planning rather than test year ratemaking purposes. As a result, it would be unwise to simply accept a new study carte blanche. The many errors alone in the Company's past studies suggest the quality of work is too low for the Commission to rely on a new wind integration study absent a very thorough and detailed review process.

Q. ABOVE YOU ALLUDED TO THE FACT THAT THE COMPANY HAS ACKNOWLEDGED NUMEROUS ERRORS IN THE WIND INTEGRATION STUDY USED IN ITS FILING. PLEASE ELABORATE.

A. The Company acknowledged many mistakes in its wind integration studies in response to ICNU data requests. In response to ICNU's DR 2.10, the Company acknowledged the following mistakes in the spreadsheet used to compute wind integration costs: 1) inclusion of only half of the capacity of Lake Side; 2) use of the incorrect minimum capacity for Lake Side; 3) exclusion of the duct firing capability of Currant Creek; 4) use of an incorrect minimum capacity for Currant

Creek; 5) a logic error that related control of the operational date of new resource; 6) incorrect inclusion of a 2012 Purchased Power Agreement contract in 2011; 7) inclusion of a 2014 combined cycle plant in 2011; 8) inclusion of a 2016 IC Aero unit in 2011; 9) improper exclusion of Dave Johnston 4 from providing reserves; 10) improper exclusion of Gadsby Steam units from providing reserves; and 11) improper exclusion of Carbon from providing reserves.[24/] Some are quite significant in terms of their overall impact changing wind integration expense by around 80%. Given this rather troubling track record, there is little reason to have confidence in the new study. It is particularly significant that the Company has stated in a public meeting it will not provide workpapers for the new wind integration study. Without workpapers, there is no way one can review the study to ascertain whether it should be used for ratemaking purposes.

Q. CAN YOU ELABORATE ON THE DIFFICULTIES INHERENT IN REVIEWING THE COMPANY'S NEW WIND INTEGRATION STUDY AT THIS TIME?

A. Yes. The study is quite complex. The study report itself is more than 60 pages long. The report contains more than 70 figures and tables. Based on the report, it appears to be much more complex than previous wind integration studies performed by the Company. Consequently, one can only assume the workpapers are likewise far more complex and voluminous. Further, the new study is based on a different model, called PaR, rather than GRID, and it is a total system model, rather than a model appropriate to the WCA. In order for parties to have a fair chance to test the accuracy of the new study, it would be necessary for the

[24/] See Exhibit No.__ (RJF-5) at 8 (Response to ICNU DR 2.10).

Company to provide access to the PaR model, in addition to the workpapers. Given the short time between the completion of the new wind study, and the filing deadline, there is no opportunity for opposing parties to conduct a fair review.

Q. IS THERE ANY REASON WHY ICNU DID NOT REQUEST THE NEW STUDY AND ITS WORKPAPERS IN THIS PROCEEDING?

A. At present, the Company has not even requested that it be used. Given the normal difficulties in identifying significant issues and preparing responsive testimony, it makes little sense for ICNU to analyze the new study proactively, particularly given the Company's statement that it would not provide supportive workpapers.

Q. ARE THERE PROBLEMS IN THE COMPANY'S ORIGINALLY FILED WIND INTEGRATION STUDY?

A. Yes. A major problem for our purposes is the fact that the Company has performed a system wide wind integration study, and applied the costs to the WCA model. Consequently, the errors discussed above related to PACE resources impacts the costs included in the WCA model. However, there is much more wind development in PACE and as a result, there is far more wind integration costs for PACE than PACW. Further, the Company has included costs related to integration of resources which are not or should not be part of the WCA model. Indeed, the Company now contends it must provide integration services for nearly 6 million MWh of wind energy system wide (based on the GRID model study filed in Oregon Docket UE 216), and has included more than 2 million MWh of wind energy requiring integration services in the test year. However, less than 1.3 million MWH actually provides service to Washington based on the WCA model. I will discuss this in more detail shortly.

Q. PLEASE EXPLAIN THE DIFFERENCE BETWEEN INTRA-HOUR AND INTER-HOUR INTEGRATION COSTS.

A. Intra-hour costs are intended to recover the costs associated with minute to minute variations and uncertainty in wind energy. It is much like the regulating margin costs which the Company incurs to accommodate the minute to minute variations in load. It is necessary to reflect these costs in the test year, as there is no intra-hour market for energy and these variations impose additional costs on the system.

Inter-hour costs are primarily those related to uncertainty surrounding hour ahead and day ahead forecasting. Because the amount of wind energy available a day or hour ahead is uncertain, additional costs are incurred due to mistakes in the balancing forecasts.

Q. COMMENT ON THE COMPANY'S DECISION TO MODEL WIND INTEGRATION COSTS OUTSIDE OF THE GRID MODEL.

A. While it is frequently reasonable to make purely financial adjustments to model circumstances that do not lend themselves well to inclusion in the model, or when the impact is not significant, this approach by the Company seems questionable to me. The Company includes $14.4 million in the test year for wind integration, most of which ($10.7 million) represents the costs adding intra-hour reserves. However, the Company has no model for costing intra-hour reserves on a minute to minute basis. Rather, the Company used a spreadsheet that simulates the intra-hour reserve costs based on <u>average monthly demands</u> in two periods (HLH and LLH). Thus, the Company has not really performed an intra-hour modeling study but a monthly average modeling. It stands to reason that an hourly model, like

GRID should be more realistic. All of the errors I discussed above were included in the Company's spreadsheet model used for costing intra-hour wind integration requirements. Further, the Company's study is seriously flawed for a number of other reasons.

Q. PLEASE DISCUSS THE PROBLEMS WITH THE COMPANY'S WIND INTEGRATION STUDY.

A. There are three over-arching problems in the Company's study: 1) failure to model load net of wind; 2) use of an overly simplistic and incorrect spreadsheet model to simulate the cost of additional intra-hour reserves; and 3) inclusion of integration costs and reserve requirements for WCA that do not provide any service to Washington customers. The first two of these problems have been addressed by other experts in the Company's various retail rate cases in other states. There has been widespread criticism of the Company's modeling in this regard.

Q. DID THE COMPANY ATTEMPT TO CORRECT THESE PROBLEMS IN ITS 2010 WIND INTEGRATION STUDY?

A. Yes. The Company did model load net wind and used a production cost model to simulate the cost of intra-hour reserves rather than its spreadsheet model. If one assumes that load and wind are not correlated (and there is little evidence to suggest they are), the equation for modeling reserve levels required for serving load and integrating wind is as follows:

$$\textbf{Reserves} \approx \boldsymbol{\alpha} \sqrt{[\sigma L2 + \sigma_W^2]}$$

In this equation, σ_L is the standard deviation of load, while σ_W is the standard deviation of wind generation. From a practical point of view, this means that load and wind reserve requirements are not additive as the Company assumes in its filing study. Instead, the incremental reserves required by wind integration are much smaller. For example, if the standard deviation of load and wind were equal, the addition of wind would only result in an increase in reserve requirements due to wind of 41.4%[25] rather than 100% as assumed by the Company. It is this "windfall" which the Company has ignored in its modeling of wind integration costs.

Q. PLEASE DISCUSS THE PROBLEMS WITH THE COMPANY'S SPREADSHEET MODELING OF WIND INTEGRATION COSTS.

A. There are a number of practical and technical problems with the Company study. The Company uses a spreadsheet to compute the cost of holding reserves before and after the addition of the intra-hour wind reserve requirements. The spreadsheet is only a monthly HLH/LLH model, not an hourly model like GRID. It also contains no logic for transmission topology, and limited logic to model operating constraints. The modeling also contains numerous errors discussed earlier and a substantial bias in its costing logic.

A serious problem in the Company modeling is the fact that the cost of holding reserves is based on the cost of the "last unit" held for reserve. The cost of wind reserves are then based on the difference between the last unit held for reserve before wind and the last unit held for reserves after wind.

Q. PLEASE EXPLAIN THIS POINT.

A. Reserves can be held on many different units on the system. Ideally, one would like to use the lowest cost resources (i.e., coal and hydro) to serve load and make

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[25] $\sqrt{2} = 1.414$

sales, and the higher cost resources (i.e., gas) to provide reserves. Consequently, operators try to dispatch reserves in the opposite order of economic dispatch (highest cost first for reserves, lowest cost last). If the system requires 300 MW of reserves in a given hour, then the cost of providing the reserves is the forgone revenue from the resources allocated to reserves. The highest running cost plants have the lowest reserve carrying cost. In the end, the total cost of providing reserves is the sum of the cost of providing reserves from all the resources that are allocated to carrying reserves. The problem in the Company approach is that it would price the cost of carrying all wind reserves at the cost of carrying the last, and most costly, increment of wind reserves. For planning purposes, this may be less troubling because we are only interested in the incremental cost of adding an additional wind resource. If these resources are not large in relation to the size of units being held for reserves, then this problem may not by itself produce a substantial bias. However, for test year ratemaking purposes we need to know the total cost of holding reserves including those required for wind integration. Consequently, the Company's method cannot be used reliably in a test year ratemaking setting.

Adjustment 11. Modeling Intra Hour Wind Integration in GRID

Q. EXPLAIN YOUR APPROACH TO MODELING OF INTRA-HOUR WIND INTEGRATION COSTS.

A. Given the wide variety of problems in the Company's model and the difficulty in correcting it, I believe it makes more sense to model wind integration requirements in GRID. To do so, I first determined the regulating margin requirements in GRID.[26]

I used the formula above to compute the reserve requirements for Load net Wind, assuming no correlation between the two. The confidential table below shows my analysis.

[redacted]

The incremental reserves required for wind were then stated as a percent reserve requirement of wind generation in the Company's wind integration model. The result was 42%. I then added 5% to that amount for contingency reserves resulting in total wind reserve requirements of 47%. An advantage of this modeling approach is that in GRID, during hours when the wind profile shows higher wind generation, more reserves are allocated, another intuitively reasonable outcome. During hours when very little wind energy is expected, fewer reserves are allocated. This also makes sense because an unexpected increase in wind energy is likely to be a much less troubling problem than a large,

[26] Contingency reserves are already modeled in GRID, and it is assumed that these requirements are minimal. Western Electricity Coordinating Council ("WECC") requires only that 5% of reserve requirements be held for contingencies for wind generation.

unexpected reduction to wind generation. In the former case, the system may need to back down on low cost plants, or arrange a quick sale, while in the later, system reliability could be at risk. Adjustment 11 on Table 1 shows the value of this adjustment applied to the Company test year GRID study. Note that this adjustment would increase substantially, if the Commission does not adopt the following adjustments, which remove integration costs from certain third party wind projects.

<u>Open Access Transmission Tariff ("OATT") Wind Integration Issues</u>

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. However, there are OATT customers who are wind farms that are owned by third parties. As a result, the Company is providing integration services to these customers without any compensation. Unfortunately, retail customers will be required to subsidize wholesale service, if this is allowed by the Commission. This issue will be discussed shortly in the context of specific adjustments. First, I will make some general points.

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 then, the Company should not be allowed to charge retail customers for providing wholesale services to its wholesale 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.[27/] 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. The Company's lack of diligence is no excuse to charge Washington customers such costs.

Adjustment 12. Non-Owned Wind Farm Inter-Hour Integration Costs

Q. PLEASE EXPLAIN THE BASIS FOR THIS ADJUSTMENT.

A. The Company includes inter-hour integration costs for non-owned wind farms for which it provides transmission services. This is much the same as the case of the 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 obtain inter-hour integration from PacifiCorp. The Company recently indicated in an Oregon discovery response that it agrees with this position.[28/]

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

28/ Exhibit No. ___ (RJF-5) at 5 (Response to OPUC DR 22, OPUC Docket No. UE 216).

Adjustment 13. Non SCL Wind Farm Integration Costs

Q. PLEASE DISCUSS THIS ISSUE.

A. The Company has included costs related to providing wind integration services to a third party who is co-owner with SCL of the Stateline wind farm. PacifiCorp provides only transmission wheeling services for the customer under the terms of its OATT. However, the OATT includes no provision for charging the customer for wind integration services. The customer provides no energy to PacifiCorp's Washington retail customers. Consequently, the Company is attempting charge retail customers for wholesale service and I recommend these costs be removed from the test year.

Adjustment 14. Oregon Wind Farm Integration Costs

Q. GRID INCLUDES WIND INTEGRATION CHARGES FOR CERTAIN OREGON QUALIFYING FACILITIES ("QF"). IS THIS APPROPRIATE?

A. No. Under the WCA model the generation and costs of QFs are specifically assigned to each PACW state.[29/] The Company excluded all of the generation of these resources in the WCA model. However, the charges for wind integration do include cost for several new QF wind farms in Oregon. These charges should be removed from the model.

Adjustment 15. Campbell Wind Farm

Q. WHAT ARE THE ISSUES RELATED TO THIS PROJECT?

A. There are two problems. First, this is another OATT customer that provides no energy to Washington ratepayers and pays no compensation for the cost of wind

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[29/] WUTC v. PacifiCorp, WUTC Docket Nos. UE-061546 and UE-060817, Direct Testimony of Mark Widmer, Exhibit MTW-1T at 6 (Oct. 3, 2006).

integration services. Just as in the case of Adjustment 13, these costs should be removed from the test year. A second problem is the fact that the Company has no direct information about the project other than its size and location. The Company simply assumes it will have a capacity factor and profile comparable to the Stateline project.[30/] Consequently, even assuming the Commission would allow retail customers to subsidize wholesale service; the costs in this case are not known and measurable and should be removed.

H. OUTAGE RATE MODELING ISSUES

Adjustment 16. Planned Outage Scheduling Errors and Issues

Q. HOW DOES THE COMPANY MODEL PLANNED OUTAGES IN GRID?

A. The Company determines the duration of outage events based on the actual outages that occurred during the four year period ended December 31, 2009. The timing of these outages is based on a purely subjective, mechanical process that is applied in the context of modeling the entire PacifiCorp system. This methodology has been the subject of litigation in other states, and resulted in a substantial disallowance in the Company 2007 Utah General Rate case[31/] and another smaller disallowance in the most recent Utah case.[32/] To my knowledge, these were the only fully litigated cases in recent years where the planned outage schedule of the Company has been decided by a state regulatory commission. For purposes of the WCA model, this is a serious problem, as the

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30/ See Exhibit No. __ (RJF-5) at 3 (Response to ICNU DR 5.5).

31/ 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).

32/ 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).

Company is using an approach predicated on modeling the entire system, which has been rejected by regulators in other states. For purposes of this case, I will focus only on the WCA modeling assumptions related to planned outages.

Q. DO YOU SEE ANY PROBLEMS WITH THE COMPANY'S ASSUMED OUTAGE SCHEDULE IN THIS CASE?

A. Yes. First, the Company assumes that the Colstrip 4 outage will occur in fall of 2011. Historically, however, Colstrip 4 outages have occurred in May and June which are lower cost periods. Second, the Company has placed the Hermiston outage during a relatively high cost period. Ordinarily, utilities try to schedule outages at the lowest cost time possible, subject to constraints. In the case of Chehalis, for example, the Company assumes the 2011 scheduled outage will occur during a time when the plant is "out of the money."

Q. HOW DO YOU PROPOSE TO MODIFY THE PLANNED OUTAGE SCHEDULE IN THIS CASE?

A. I propose to move the Colstrip outages to late spring (to coinciding with historical outage patterns). The starting date I assume is consistent with actual outages that have occurred in prior years and fits well with the assumed schedule for Bridger.

For Hermiston, the termination of the low cost gas contract will result in a change in scheduling strategy. Under the old contract, gas prices for Hermiston were typically quite low and the plant operated nearly all the time. Once the contract expires, Hermiston's duty cycle will change, and it will operate more like Chehalis. Consequently, historical outage schedules do not provide the best guidance for scheduling planned outages. As a result, I placed the Hermiston outage during a period of time (late February through March 2012) when the economics of running the plant are least attractive. This is consistent with actual outages in prior years.

Adjustment 17. Colstrip 4 2009 Outage

Q. EXPLAIN THE USE OF THERMAL DERATION FACTORS IN GRID.[33/]

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 5%, GRID assumes a thermal deration factor of 95%. This means that only 95% 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.

Q. ARE THERMAL DERATION OR UNPLANNED OUTAGE FACTORS AN IMPORTANT DRIVER IN OVERALL NET POWER COSTS?

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

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, 2006-2009 used by the Company to compute outage rates. As a result, the Company

33/ Hereafter in this testimony, unplanned outages and outage rates will be discussed, as distinguished from the planned outages discussed above. Even if the text does not specify it, I will be discussing unplanned outages.

computes an average outage rate for Colstrip 4 of [redacted] For 2009 this equates to an outage rate in excess of 50% for the unit.

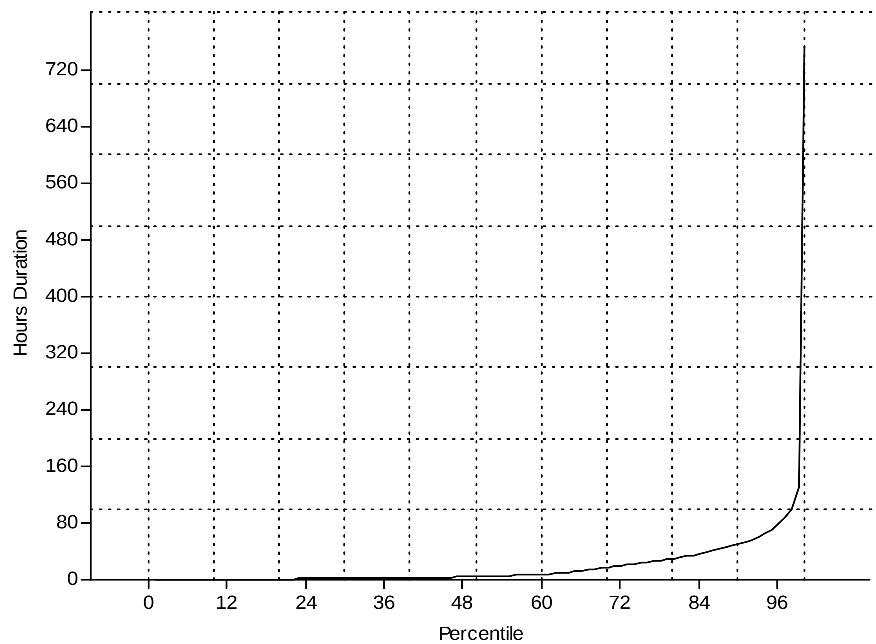
Q. SHOULD THIS ENTIRE EVENT BE REFLECTED IN RATES?

A. No. This was an extremely rare event, and not one likely to recur once every four years, as is assumed in the Company's four year moving average calculation. It is very unlikely that this event is representative of conditions in the rate effective period. As a result, it is quite likely including this event in the test year outage rate will produce an inaccurate forecast.

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend this outage be capped at 28 days in the outage rate calculation. This approach was recently recommended by the Company 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. 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 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 poor outage rates from the four year average calculation. However, prior to applying its collar, PacifiCorp proposed to cap outage durations at 28 days.[34/] 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 no several other competing alternatives and a decision is pending. In any case, capping the Colstrip outage at 28 days would result in an outage rate for 2009 that would not 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 Colstrip outage rate.

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

A. Yes. In 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

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[34/] 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).

> 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.[35]

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 2009 Colstrip outage to 28 days. The impact of this adjustment is shown on Table 1.

<u>Adjustment 18. 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 resulting from fuel quality problems. Utilities report to North American Electric Reliability Council

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

("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 of these circumstances in its rebuttal case, I recommend the Commission disallow the additional costs resulting for this problem.

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

A. Yes. The Company has included $1.792 million 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 18 on Table 1 includes both of these adjustments.

<u>Adjustment 19. Minimum Loading and Deration Adjustment</u>

Q. WHAT IS THE PURPOSE OF ADJUSTMENT 19?

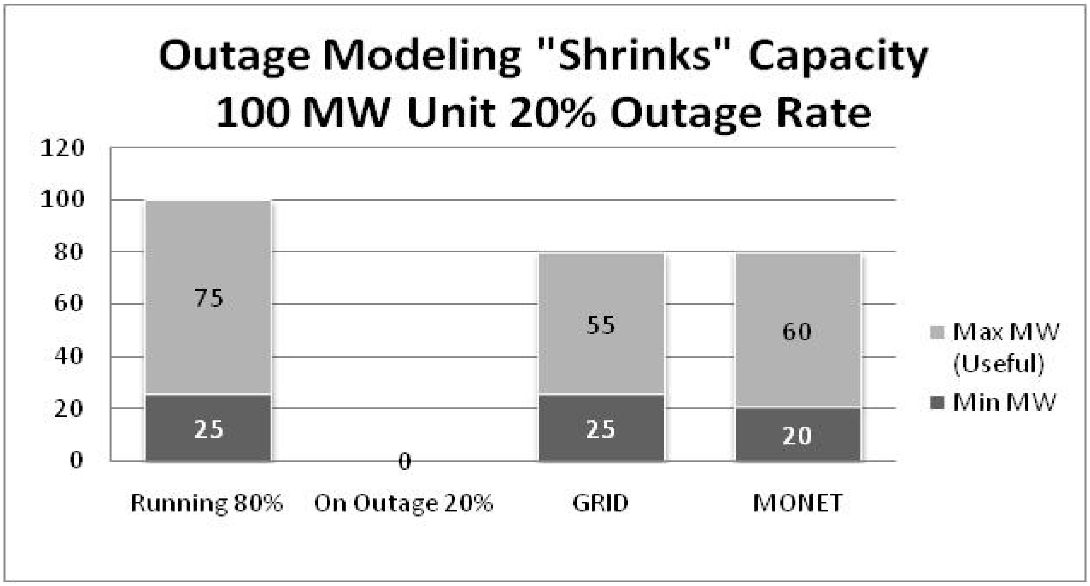
A. This adjustment reflects ICNU's proposed adjustment to apply deration factors to minimum loadings and to adjust heat rates so they are not artificially inflated due to the deration of unit maximum capacities. This approach is already used by at least one other regional utility, Portland General Electric ("PGE"), in its power cost model, MONET. I believe this represents standard industry practice, as do other experts. For example, in Utah Docket No. 07-035-93, another power cost modeling expert, Mr. Philip Hayet, testified that this methodology is well accepted in the community of production cost modeling experts.[36/] Further, this methodology was also applied in production cost models I developed for EBASCO Services more than twenty five years ago. These models were in use by around twenty major utility companies in the early 1980s. Finally, PacifiCorp itself uses the same method I recommend for modeling of fractionally owned units, such as Bridger and Colstrip.

Q. WHY IS THIS ADJUSTMENT NECESSARY?

A. In GRID, and 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.

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

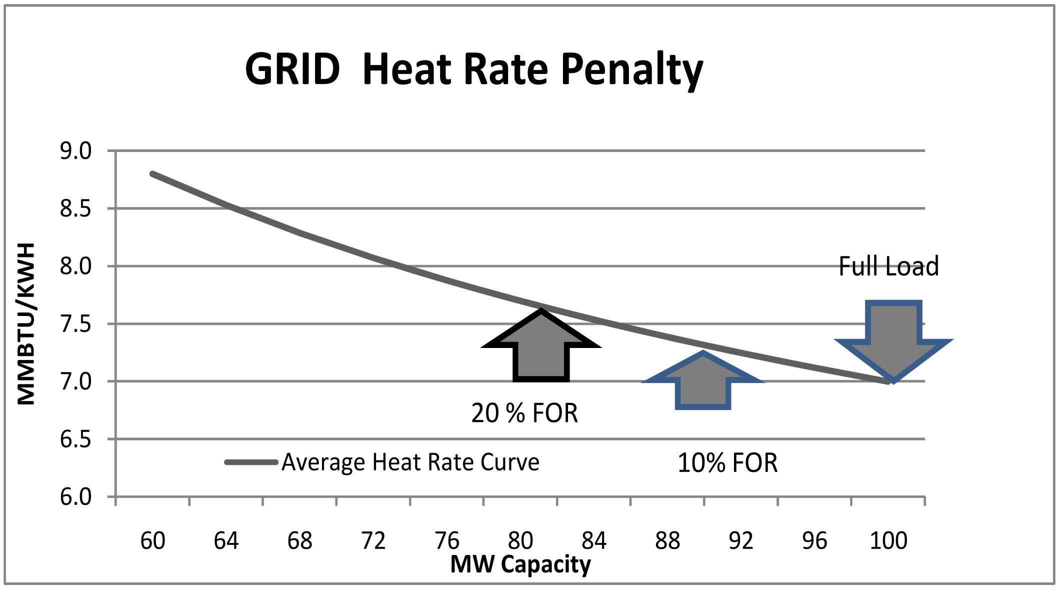
Figure 3



The figure above shows this process. The most useful capacity of a unit is the difference between the minimum and maximum capacity. This is the capacity that can be used to provide reserves and follow load. Unless the minimum capacity is also derated (in this case from 25 to 20 MW) as PGE does in the MONET model, the most useful capacity in understated. In my adjustment, there is a perfect symmetry: The maximum, minimum and most useful capacity are all derated by the same amount (20% in the above example). In the PacifiCorp method, maximum capacity is derated by 20%, minimum capacity by 0%, and the most useful capacity by 27%. The PacifiCorp method is unbalanced.

A second problem with the GRID modeling is that while the capacity of units is derated, 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. My adjustment simply invokes the input already used by the Company for fractionally owned units to do the same thing in GRID. As the Company's method is unrealistic, I recommend the WUTC adopt this adjustment in this case.

Figure 4



Q. HAS THE COMPANY ALREADY CONCEDED THAT IS A VALID ISSUE?

A. In Oregon Docket UM 1355, Mr. 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."[37/]

[37/] 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).

Q. IS MR. DUVALL CORRECT ABOUT THIS?

A. No. In fact, the great majority of this adjustment is due to the problem created when the heat rate curve is applied to the full derated capacity, thus overstating the heat rate when the unit is fully loaded.

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.

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 [redacted] This may seem like an inconsequential amount however, this problem occurs nearly every hour, for every unit and can become a very substantial sum of money.

[redacted]	
[redacted]	
[redacted]	[redacted]

Q. HAVE YOU PERFORMED AN ANALYSIS WITH GRID THAT ISOLATES THE IMPACT OF THIS PROBLEM FROM ALL THE OTHER ELEMENTS OF YOUR PROPOSED ADJUSTMENT?

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 was over $1 million on a WCA basis. This amounts to more than 82% of the total heat rate component of the adjustment ($1.2 million).

Q. DOES THIS IMPLY THAT YOU DO NOT BELIEVE THE REMAINING AMOUNT OF YOUR ADJUSTMENT IS VALID?

A. Not at all. The remaining portion of the adjustment is equally valid. I am merely presenting these results to show the component of the adjustment to which the Company seems to have already conceded.

Adjustments 20 and 21.

Q. WHAT IS THE PURPOSE OF ADJUSTMENT 20?

A. It has been the recent practice of the WUTC to allow updates to forward prices during a rate case. Adjustment 20 shows the impact of using a more recent forward price curve, based on the Company's response to WUTC 143 and ICNU DRs in Set 16. I excluded half of the Idaho Point to Point transmission rate update as being PACE related for the reasons explain in the discussion of Adjustment 8.

Q. IS CHEHALIS ASSUMED TO BE CAPABLE OF PROVIDING OPERATING RESERVES IN THE WUTC 143 GRID UPDATE?

A. No. This is a major change from the Company's originally filed case. The Company now assumes that Chehalis is incapable of providing operating reserves, due to BPA's denial of the request for dynamic scheduling. BPA's website explains the basis for the denial as being due to "technical and or communications limitations." There is no reason why a modern combined cycle power plant should be incapable of providing operating reserves. If the Company has now learned that it will be unable to obtain such capability from Chehalis, it certainly calls into question the prudence of the acquisition and the Company's due diligence.

Q. WHAT IS YOUR RECOMMENDATION?

A. This is a very troubling development for a variety of reasons. First, given the lateness of the Company's update, it is not possible to conduct discovery on this matter. As prudence is now a concern, this could be time consuming. Second, the current denial by BPA may not the "last word" on the matter. There may be solutions available that would enable BPA to provide dynamic scheduling. Exploring this would also require additional discovery. Third, there may be options available other than BPA which would facilitate a solution. Finally, the modeling of this change is also open to question. If the resource is still capable of providing ready reserves about 75% of the value of spinning reserves could be obtained. However, it would take additional discovery to determine if that is a feasible option. For all these reasons, I recommend the WUTC reject the modeling change related to Chehalis reserve carrying capability.

Q. WHAT IS THE PURPOSE OF ADJUSTMENT 21?

A. In a model such as GRID there is an interaction among adjustments. When all adjustments are combined, the total effect is usually a bit less than the sum of all adjustments individually. Changes in forward price curves also impact the value of other adjustments. For example, a decrease in forward prices will result in a reduction to the cost of outage. As it is not known what final adjustments the Commission will approve, Adjustment 21 serves as a placeholder for the balancing impact of all approved adjustments. The level of the adjustment is based on experience in similar situations.

G. OTHER ISSUES

Adjustment 23. REC Sales Revenue

Q. HAS THE COMPANY INCLUDED ANY REVENUE FROM SALE OF RENEWABLE ENERGY CREDITS ("RECS") IN THE TEST YEAR?

A. No. The Company excludes the actual 2009 $4.2 million REC sales revenue from the test year based on the assumption that all RECs should be banked, owing to the fact that starting in 2011 Washington will have a Renewable Portfolio

Standard ("RPS"). The Washington RPS requires renewable energy generation equal to 3% of all Washington jurisdictional sales by December 1, 2012. Under the Washington RPS, RECs may be banked, but only for one year.

Q. IS THE COMPANY'S STATED POLICY OF NOT SELLING ANY WASHINGTON ALLOCATED RECS REASONABLE?

A. No, for two reasons. First, some renewable resources produce RECs that are eligible for compliance requirements in other states, but not eligible for the Washington RPS. The Company has been successful in selling these types of RECs. There is no advantage to the Company or to customers in refraining from selling RECs from these resources. Second, the initial Washington RPS requirement is only 3% of total energy sales. This is an amount far less than can be produced by Washington's allocation of RECs for the test year. The response to ICNU DR 13.7 shows that in the first two years the RPS is in effect, WCA resources will produce more than [redacted] RECs as required for compliance purposes. Given the fact that RECs can only be banked for one year, it is unreasonable to assume that none of the Washington allocated RECs should be sold either. In the end, the Company's policy of not selling Washington allocated RECs would amount to simply wasting these important resources. This hardly seems in keeping with the intent of an RPS and would be imprudent, given the rate inputs from these new wind resources.

Q. WHAT HAS BEEN THE RECENT TREND IN REVENUES FROM REC SALES FOR PACIFICORP?

A. At a system level REC sales revenues are increasing rapidly. For 2009 REC sales revenues were $50.8 million.[38] For 2010, the Company projects REC sales revenues of approximately $91.8 million.[39] Consequently, even with the RPS limiting the number of RECs available for sale in the rate effective period, the Company will likely see an increase in Washington allocated REC revenues.

Q. HOW DID YOU COMPUTE YOUR REC REVENUE ADJUSTMENT?

A. From ICNU DR 13.7, I determined the amount of RPS eligible RECs surplus to Washington's needs for 2012. Based on public record forecasts of REC revenues the Company filed in the current Idaho case, I determined the Company's average 2010 projected price for wind energy RECs.[40] [redacted] Test year volumes for non-wind REC sales were also based on the Confidential Attachment to the Response to ICNU DR 9.1-2. The resulting revenues, $4.87 million, provide a reasonable estimate of REC revenues allocated to Washington during the rate effective period. This level is close to the 2009 actual REC revenues, and but less than the most recent 12 months of data available, as presented in Confidential Attachment ICNU DR 9.1-2. Finally, the Company's projections of Washington allocated 2010 REC revenues used in the current Idaho general rate case are close to my projected figures.

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[38] WUTC v. PacifiCorp, WUTC Docket No. UE-100749, R. Bryce Dalley Exhibit 3 at 3.5 (May 4, 2010).

[39] Re Rocky Mountain Power 2010 General Rate Case, Idaho Public Utility Commission Docket No. PAC-E-10-07, Steven R. McDougal Exhibit 2 at 3.6.3 (May 26, 2010).

[40] Id.

Q. HAVE YOU IDENTIFIED ANY CONCERNS RELATED TO THE COMPANY'S ALLOCATION OF RECS TO THE VARIOUS STATES?

A. Yes. The Company uses different allocation methods for different purposes. For the test year adjustment discussed above, the Company computed the Washington revenue based on the system SG (approximately 8%) factor, applied to system level revenues. For the Western Renewable Energy Generation Information System ("WREGIS"), the Company also uses the SG factor to allocate RECs.[41/] However, for purposes of reporting the WUTC, the Company allocates WCA resource RECs on the basis of the SG factor but allocates no RECs for non-WCA resources. However, under the WCA model, Washington is paying for approximately 22% of WCA wind resources based on the CAGW factor. Consequently, the Company is understating Washington allocated RECs in its quarterly reports to the Commission. The Company is using zero percent allocation of non-WCA resource RECs, but only 8% of the WCA resources RECs are being allocated to Washington. This issue in not specifically a concern for this rate case, but should be addressed at some point.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

41/ See Exhibit No.__ (RJF-5) at 4 (Response to ICNU DR 13.1).