Witness OCS 4D

BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Application of	**)**	**Docket No. 11-035-200**
Rocky Mountain Power for Authority to	**)**	
Increase Its Retail Electric Service Rate in	**)**	**Direct Testimony of**
Utah and for Approval of Its Proposed	**)**	**Randall J. Falkenberg**
Electric Service Schedules and Electric	**)**	**On Behalf of the**
Service Regulations	**)**	**Utah Office of**
	)	**Consumer Services**

REDACTED

Confidential Material Redacted

June 11, 2012

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

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

Q. PLEASE STATE YOUR OCCUPATION, EMPLOYMENT, AND ON WHOSE BEHALF YOU ARE TESTIFYING.

A. I am a utility regulatory consultant and President of RFI Consulting, Inc. ("RFI"). I am appearing on behalf of the Office of Consumer Services ("OCS").

Q. WHAT CONSULTING SERVICES ARE PROVIDED BY RFI?

A. RFI provides consulting services related to electric utility system planning, energy cost recovery issues, revenue requirements, and other regulatory matters.

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND APPEARANCES.

A. My qualifications and appearances are provided in Exhibit OCS 4.1D.

I. INTRODUCTION AND SUMMARY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony addresses PacifiCorp's Generation and Regulation Initiatives Decision ("GRID") model study of Net Power Costs ("NPC") for the projected test period ending May 31, 2013. I also address issues related to the Company's proposal to update the Net Power Cost study during rate cases.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. I have identified and quantified approximately 25 adjustments to the Company's Test Year NPC GRID study. These adjustments are shown on Table 1 and are summarized below. In cases where no adjustment is identified, the comments presented are informational or for comparative purposes only.

Q. HOW DID YOU COMPUTE YOUR PROPOSED ADJUSTMENTS?

A. Where practical or necessary, I ran the GRID model with modified inputs to compute the adjustments. In some instances, the adjustments are purely financial adjustments computed outside of the model for practical reasons. For example, adjustments involving fixed costs (e.g. fixed transmission costs) have no impact on the GRID simulation, and therefore do not require a model run. In a few cases, if the GRID model does not possess the necessary modeling capability, a purely financial adjustment is proposed to address the issue. The Company uses this approach as well, and applies purely financial adjustments for inter-hour wind integration and start up fuel costs.

All adjustments are computed against the Company's original GRID study and use inputs applicable to the Company's initial filing. Combining adjustments can and often will change their value. The Company's final compliance filing is required to combine all Commission-approved adjustments into a final GRID run which may modify the value of specific adjustments.[1] Though I include the Company's updated NPC filing and discuss it to a limited extent here, analysis is not yet complete and OCS may file additional testimony during the rebuttal phase concerning the NPC update.

[1] In its May 1, 2012 Order, Docket 11-035-T10, the Commission required the Company to submit a compliance NPC study after a general rate case order is issued.

Table 1

Summary of Recommended Adjustments - $

	Total Company		Est. Utah Jurisdiction
		SE	42.953%
I. GRID (Net Variable Power Cost Issues)		SG	43.155%
PacifiCorp Request NPC	1,499,512,657		644,658,741
A. Company Update			
1 Company Update	(20,348,123)		(8,657,020)
Company Updated NPC	1,479,164,534		636,001,721
B. Reserve Modeling Adjustments			
2 Reserve Requirements Adjustment	(9,288,161)		(3,998,925)
3 Non-Owned Wind Reserves Variable Cost	(2,627,614)		(1,131,293)
C. GRID Start Up Logic and Costs			0
4 Combined Cycle Must Run Modeling	(298,388)		(128,468)
5 Gadsby Cycling	(902,292)		(388,473)
6 Lake Side Start Up Cost	(1,642,442)		(707,137)
D. Long Term Contracts			
7 SMUD Shaping Error Correction	95,641		41,177
8 BHP Sales Shaping	(1,003,009)		(431,836)
9 UMPA II Shaping	(82,454)		(35,500)
10 APS Contract Modeling	(385,843)		(166,121)
11 Biomass	(923,442)		(397,579)
E. Hydro Logic and Inputs			
12 Merwin Reserve Capability	(318,410)		(137,088)
13 Lewis River Hydro Correction	(730,203)		(314,382)
14 Lewis River Hydro Modeling	(2,069,026)		(890,798)
15 Hydro Forced Outage Rates	(1,034,768)		(445,509)
F. Transmission Issues			
16 DC Intertie Transmission Cost	(4,696,440)		(2,022,005)
17 Centralia Point to Point	(774,516)		(333,460)
18 Dynamic Overlay	(919,179)		(395,743)
19 Transmission Loss Adjustment	(1,704,041)		(733,658)
20 Non-Firm Transmission	(3,344,480)		(1,439,932)
H. Planned and Forced Outage Modeling Issues			0
21 Extended Planned Outages	(649,490)		(279,632)
22 Lake Side Outage Rate	(2,537,161)		(1,092,349)
23 Colstrip 4 Outage Rate	(1,046,687)		(450,641)
24 Naughton 3 Outage Rate	(233,285)		(100,438)
25 Min Loading Deration and Heat Rate Modeling	(6,018,191)		(2,591,072)
26 Balancing Adjustment - est	2,037,468		877,211
Subtotal NPC Adjustments -	(41,096,414)		(17,693,650)
Allowed - Final GRID Result*	1,438,068,120		618,308,071

<u>Overview of Net Power Cost (GRID)</u>

PacifiCorp's updated NPC request of $1.479 Billion (total Company) in NPC is overstated by $41 million. OCS recommends NPC of $1.438 Billion, resulting in a reduction to the Utah allocated revenue requirement of $17.7 million. The specific adjustments recommended by the OCS are shown in Table 1 on the previous page and summarized below.

<u>A. Company Update</u>

<u>Adjustment 1:</u> I have incorporated the Company's update into the total recommended NPC; however, OCS may file additional testimony concerning the update in the rebuttal filing.

<u>B. Reserve Modeling Adjustments</u>

The Company continues to use the 2010 Wind Integration Study ("the Wind Study") as the basis for determining GRID reserve inputs. The Wind Study contains numerous implementation errors including use of unreliable data, incorrect regression models, math errors, and double counting of several wind farms.[2] The most serious errors resulted from the erroneous regression models used to estimate integration requirements for projects lacking a complete record of actual data. Consequently, the Wind Study should not be used as the basis for determining GRID inputs.

<u>Adjustment 2.</u> This adjustment corrects the GRID Study by using more realistic reserve requirements to establish the GRID inputs.

<u>Adjustment 3.</u> This adjustment removes the costs due to added reserve requirements resulting from non-owned wind projects.

<u>C. GRID Commitment Logic and Start-Up Energy</u>

<u>Adjustment 4.</u> While Mr. Duvall states that the Gadsby Combustion Turbine ("CT") units are allowed to cycle (abandoning the prior "must run" modeling), the Company GRID modeling requires them to run every day, whether they are needed or not. This adjustment corrects that problem.

<u>Adjustment 5.</u> This adjustment partially reverses the "must run" modeling of Currant Creek, consistent with current operations. Currant Creek is really two independent generators, and should be modeled as such. The must run designation is appropriate for only one unit.

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[2] Rolling Hills, Rock River, Leaning Juniper and Goodnoe.

<u>Adjustment 6.</u> The Company models very high and unrealistic start up costs in computing the Lake Side commitment screens.[3] This results in far fewer starts for the plant than actual operations and increases NPC. This adjustment corrects this problem.

D. Long Term Contracts

<u>Adjustments 7-9.</u> The Company incorrectly models Sacramento Municipal Utility District ("SMUD"), Black Hills Power ("BHP"), and Utah Municipal Power Authority ("UMPA") II call option sales contracts. The SMUD contract modeling contains an input error, which I have corrected. The UMPA and BHP contracts overstate NPC by assuming the counterparties will take power in the highest cost hours possible. I have modeled more realistic schedules for the later two contracts.

<u>Adjustment 10.</u> The Company models a simple monthly screen for the Arizona Public Service ("APS") Supplemental call option purchases. I use a more realistic daily screen consistent with the Company's modeling of thermal unit screens and actual operations.

<u>Adjustment 11.</u> The Company update includes a new contract for the Oregon Biomass Qualifying Facility ("QF"). The contract prices are excessive and inconsistent with the applicable approved tariff because they assumed that the Biomass QF project provides the same economic dispatch benefits as a combined cycle plant. The contract with the Biomass QF does not allow the Company to dispatch the project for economics. This adjustment addresses the problem.

E. Hydro Logic and Inputs

<u>Adjustment 12.</u> The Company acknowledges that the Merwin hydro plant can provide reserves at certain times and in the past four years it did so for [redacted] of the time. This adjustment includes the four-year average level of reserves available from the plant.

<u>Adjustments 13-14.</u> The Company includes the hydro Lewis River loss of efficiency adjustment because it believes the efficiency of hydro units modeled in GRID exceeds actual performance. The adjustment should be eliminated altogether because the Company has implemented it in a one-sided manner. The Company ignores the fact that the efficiency of thermal units is understated in GRID (see adjustment 25). Either both issues should be corrected, or both should be ignored. If the Commission decides to retain the loss of efficiency modeling, Adjustment 13 is necessary to correct errors in the Company's calculation.

[3] Screens determine when cycling units will operate because GRID's logic doesn't derive the most optimal schedules. This issue was litigated in prior cases and the Company has now adopted a more realistic means of addressing this problem.

Adjustment 15: Hydro Forced Outage Modeling. The Company overstates energy lost from forced outages at hydro resources with storage capability. This adjustment corrects that problem.

F. Transmission Issues

Adjustments 16-17. The DC Intertie and Centralia Point to Point contracts do not provide reasonable or compensatory benefits in the test year. There are no transactions that rely on the Centralia contract, and the DC Intertie is used solely for marginal transactions with the Nevada Oregon Border ("NOB") market. Both contracts were originally used to deliver energy from now expired wholesale contracts. The Company has failed to demonstrate the prudence or necessity of either transaction.

Adjustment 18. This Dynamic Overlay can be used in three different ways: to transfer energy from PACE to PACW, to transfer reserves from PACW to PACE, or transfer reserves from PACE to PACW. The Company models only the least useful option in GRID. This adjustment provides a more realistic and accurate modeling of this resource consistent with actual operations.

Adjustment 19. The Company used the five-year average of transmission losses for 2006-2010. I have updated the loss calculation to the average for the five-year period ended December 31, 2011. The Company has made large transmission investments in recent years which reduce losses. Savings in losses should be reflected in the test year.

Adjustment 20. The Company has not modeled non-firm transmission based on the Commission approved methodology. Instead, non-firm transmission is combined with Short-Term Firm transmission. The Short-Term Firm methodology models cost based on a fixed single year value, while capacity is based on a four-year average. This approach, combining non-firm and Short-Term firm, is unrealistic and fails to recognize that nearly all of these transmission purchases are now non-firm transactions priced on a volumetric rather than fixed price basis. This adjustment models non-firm transmission based on the most recent cost and capacity data consistent with other transmission contracts modeled in GRID.

G. Planned and Forced Outage and Other Modeling Issues

Adjustment 21: Several planned outages were longer than necessary due to poor contractor performance. This resulted in liquidated damages payments being made to the Company. I remove the impact of the outage extensions from the test year.

Adjustments 22-23. These adjustments reduce the impact of two exceptionally long outages in the four-year average outage rate calculation. It is unrealistic to assume such extreme events will occur once every four years. These adjustments correct this problem.

<u>Adjustment 24.</u> The Company includes an outage at the Naughton plant caused by [redacted] The costs of such events should be assigned to the Company rather than customers.

<u>Adjustment 25.</u> GRID systematically overstates heat rates of thermal units. In part this is due to its modeling of forced outage rates as capacity derations. When GRID models a unit at its derated maximum capacity, the heat rate normally exceeds the full loading average heat rate. This adjustment addresses this problem.

H. Balancing/Overlap Adjustment

<u>Adjustment 26.</u> OCS proposes that the Company perform a final GRID run, which combines all Commission-approved adjustments. This adjustment is a placeholder for the impact of combining adjustments and removing overlapping adjustments.

NPC Update Issues

OCS witness Michele Beck addresses policy issues concerning NPC updates in this and future cases while I address implementation issues. NPC updates should be limited to one update filed by the Company mid-way between the Company's initial filing and the intervenor testimony filing date. The scope of updates should be limited to items readily verifiable and opposing parties should have the opportunity to address updates at the time of the rebuttal testimony filing. Regardless of the Commission's decision regarding updates, a final GRID run should be performed at the end of the case to incorporate all Commission approved adjustments.

II. NET POWER COSTS AND GRID

Q. PLEASE DEFINE NPC AND EXPLAIN HOW THE COMPANY DETERMINES TEST YEAR NPC LEVELS.

A. NPC is computed as the sum of fuel, transmission wheeling, and purchase power expense less revenue from sales for resale. NPC encompasses FERC expense accounts 501 (fuel), 503 (steam), 547 (other fuel), 555 (purchased power) and 565 (wheeling expense). Account 447 (sales for resale) is a revenue account that is credited against NPC.

The Company uses the GRID model to determine NPC. GRID is intended to simulate the least cost operation of the Company's production system, as it is used to meet retail and wholesale load requirements. GRID simulates the operation of the generation system, known purchase and sale contracts, and the transmission system used to move power from the source to the various load centers and delivery points. GRID has been used in all of the Company's rate cases and power cost cases since around 2003.

Q. THE SETTLEMENTS IN THE PRIOR CASE AND PRIOR COMMISSION ORDERS LEFT SOME NPC ISSUES UNRESOLVED. HAS ANY PROGRESS BEEN MADE TOWARDS RESOLVING THESE ISSUES?

A. Yes. In prior cases there have been numerous NPC adjustments. Progress has been made in many areas, including modeling of certain issues such as planned outages schedules and screens to address proper unit commitment. Further, the Company states that it has addressed in the filing a number of the issues OCS raised in the last case.

Despite this progress, NPC remains a dynamic issue, and new issues have arisen in this case, particularly with regard to the Company's modeling assumptions related to reserve requirements, wind integration, and other issues. Further, in some instances, the modifications proposed by the Company in response to OCS adjustments advanced in prior cases do not provide realistic results or a noticeable improvement over the Company's prior methods.

A. The Company Update

Adjustments 1

Q. WHY HAVE YOU INCLUDED THE COMPANY UPDATE IN TABLE 1?

A. The proposed update is listed as the first adjustment and is provided for illustrative purposes. Because the updates were not filed until May 11, 2012 and the update workpapers were not provided OCS until May 14, 2012 (shortly before we needed to begin finalizing the OCS testimony) I computed all of my proposed adjustments relative to the Company base. I have examined the Company update to see if any of the adjustments included overlap with my proposed adjustments, and removed the overlaps in the Final Balancing/Overlap adjustment. OCS continues to examine the update and may file additional testimony relative to this issue in the rebuttal phase as permitted by the Commission's scheduling order.

B. Reserve Modeling Adjustments

Adjustment 2 Reserve Requirements Adjustment

Q. PLEASE EXPLAIN THE VARIOUS TYPES OF RESERVES MODELED IN GRID AND THEIR IMPORTANCE TO NET POWER COSTS.

A. GRID models two types of reserves: contingency reserves and regulating margin reserves. The purpose of contingency reserves is to compensate for unexpected outages of generating resources or other similar events. Regulating margins are spinning reserves which are available to meet very short term fluctuations in load requirements, or variations in the output of naturally variable generation sources, such as wind power. Reserves requirements of any type generally increase net power costs because they require units to operate at less than full capacity, reducing off system sales and increasing generator heat rates.

Q. HOW DID THE COMPANY DETERMINE THE TEST YEAR CONTINGENCY RESERVE REQUIREMENTS?

A. Determination of contingency reserves is formulaic.[4] Contingency reserves are determined from the standard formula which equals 7% of the thermal generation and 5% of hydro and wind generation. It is split equally between spinning reserves (capacity available in less than ten minutes) and ready reserves (capacity available in ten minutes).

Q. HOW DID THE COMPANY DETERMINE THE TEST YEAR REGULATING MARGIN REQUIREMENTS?

A. As in the 2011 GRC, the Company relies on its deeply flawed 2010 Wind Integration Study ("Wind Study"). In the 2011 case, I explained how the Wind Study is completely invalidated due to the volume and severity of errors within the Study. Rather than repeat that testimony here in its entirety, my testimony in this case includes a copy of my Technical Appendix from the last case (Exhibit OCS 4.2D). That Appendix documents and explains the problems with the Company's analysis. It also provides details concerning the OCS analysis of wind integration requirements.

Q. HAS THE COMPANY MADE ANY CORRECTIONS OR ADJUSTMENTS TO THE WIND STUDY IN THE PAST YEAR?

A. No, the Company has not made any corrections to the Wind Study, despite the presence of dozens of acknowledged errors which are documented in Exhibit OCS 4.2D.

Q. MR. DUVALL TESTIFIES THAT TEST YEAR WIND INTEGRATION COSTS ARE ONLY $3.44/MWH. HOW DOES THIS COMPARE TO HIS PRIOR ESTIMATES?

A. The Company has used a wide range of estimates in the past two years. In the Wind Study itself, the Company reported total wind integration costs of $9.70/MWH. In

[4] However, the GRID model contains an error which overstates the level of required ready reserves by more than 20 MW, on average. In recent discovery, the Company has acknowledged that the calculations of contingency spinning and ready reserves are done at different times in the model. My analysis demonstrates that the ready reserves are overstated because they fail to account for capacity being dispatched below the maximum available level. This problem does not appear to produce a test year adjustment in this case because the Company has an excess of capacity that can produce ready reserves. However, this inaccuracy could make a difference in other situations and I recommend the Commission require the Company to correct this error in its next filing.

Docket 10-035-124, the Company modeled $7.06/MWH in its test year.[5] In its pending FERC filing, the Company is proposing to collect only $1.44/MWH from its wind transmission customers for fixed costs of wind integration services but nothing for variable wind integration costs as modeled in GRID.[6]

Q. WHAT IS YOUR CONCLUSION ABOUT THE COMPANY'S ESTIMATE OF WIND INTEGRATION COSTS?

A. The wide range of wind integration costs estimates put forth by the Company clearly undermines any contention that the Company has actually succeeded in developing a reasonable wind integration cost analysis. We must start from scratch in development of proper inputs for reserve modeling in GRID for purposes of calculating NPC in this case.

Q. HOW DID YOU DETERMINE THE REGULATING MARGIN INPUTS?

A. The inputs were determined starting with the results of the Wind Integration analysis I performed presented in Exhibit OCS 4.2D. However, I augmented that analysis with consideration of actual 2010 regulating reserve requirements.

Q. WHY SHOULD THE COMMISSION RELY UPON THE OCS ANALYSIS OF WIND INTEGRATION REQUIREMENTS AS OPPOSED TO THE COMPANY'S RESULTS?

A. The OCS analysis uses the same basic formulation as proposed by the Company, but eliminates many of the problems in the Company study. The various math errors have been eliminated. Double counted resources have been removed. The results are based on 2009 and 2010 data, which requires far less use of simulated data. When simulated data is required, a more realistic methodology was used to compute it. It also is based on a more realistic CPS2 reliability target rather than the overstated figure used by the Company.

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[5] OCS DR 33.8 Docket No. 10-035-124.

[6] As will be discussed shortly, these are only the fixed capacity costs associated with wind integration. The Company proposes no charge for FERC customers for variable wind integration costs. It is the variable integration costs which the Company models in GRID.

Q. HAS THE COMPANY ATTEMPTED TO DETERMINE ITS ACTUAL REGULATING RESERVE REQUIREMENTS?

A. The Company has performed various analyses purporting to compute its 2010 actual reserve requirements which it has filed in other cases.[7,8,9] In those analyses, the Company differentiated between two types of reserves – regulating reserves (which must be spinning and available within ten minutes) and load following reserves (which are available in more than ten minutes, but less than sixty minutes.)

Q. DO YOU AGREE WITH THE RESULTS OF THESE ANALYSESE PERFORMED BY THE COMPANY??

A. No. These analyses have various shortcomings. In Mr. Duvall's current Wyoming testimony he computed regulating reserve requirements of 344 MW and load following reserves of 196 MW.[10] However, the load following figure is flawed because of numerous errors and I believe it merely reflects temporarily idled capacity. Consequently, I don't believe it is the real driver of actual reserve requirements.

Mr. Duvall has testified previously, that even the spinning reserve allocations he used to compute the regulating (ten minute) reserves merely represent the *difference between capacity on line and capacity dispatched, and not actual reserve allocations*.[11] Consequently, even the 344 MW regulating reserve calculation is likely to be overstated. However, for purposes of this case, it does provide some value as limited check on the data used in GRID.

Q. IS THE USE OF 2010 ACTUAL RESERVES OUTDATED NOW?

A. No. Load growth has not been substantial since 2010, and there has been little expansion in wind capacity. As explained in Exhibit OCS 4.2D, Control Performance Standard 2

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[7] Rebuttal Testimony of Gregory N. Duvall, Wyoming Public Service Commission Docket No. 20000-384-ER-10, page 58.

[8] Idaho Public Utilities Commission Docket No. PAC-E-11-12, Exhibit Duvall, Direct, page 4.

[9] Wyoming Public Service Commission, Docket No. 20000-405-ER-11, Duvall Direct Testimony, page 12.

[10] Id.

[11] Docket No. 09-035-23, Rebuttal Testimony of Gregory N. Duvall, page 20, lines 431-434.

("CPS2") is a major driver of reserve requirements. In 2010, the Company exceeded the CPS2 requirement by a substantial amount. Finally, we have little choice to do otherwise. The Company did not achieve the CPS2 target of 90% in 2011 due to participation in a field trial of an alternative reliability metric.[12] As a result, more recent data would not necessarily provide meaningful results.

Q. HOW DO THE REGULATING RESERVES MODELED IN GRID COMPARE TO THE ACTUAL 2010 LEVELS COMPUTED FROM THE COMPANY DATA?

A. The Company Test Year GRID study contains 586 MW of regulating (ten minute) reserves. It also included 214 MW of load following (sixty minute) reserves. This is based on the same calculation as performed by the Company to determine the actual load following reserves. Both figures greatly exceed the Company's own actual 2010 calculation. The OCS GRID study includes 467 MW of regulating reserves, an amount well in excess of the actual requirement, as well as 155 MW of load following reserves. While the load following reserves are less than the Company's computed actual 2010 value the shortfall can be more than covered by the excess of regulating reserves. Further, as discussed above, the load following reserves computed by the Company are excessive and unrealistic. The level of reserves in the OCS study is higher than the actual 2010 levels which may be unnecessary. However, it provides a conservative level for this adjustment, and insures that reserve requirements will be met or exceeded throughout the year. Further, the impact on total coal generation is reasonable and provides for conservative results using this level of reserves.

[12] OCS DR 2.101.

Table 2
Actual 2010 Reserve Requirements v. GRID

	======Company========		===GRID Model Studies===	
Type of Reserves	**2010 Actual***	**Wind Study***	**Company**	**OCS**
Regulating Reserves	**344**	**367**	**586**	**467**
Load Following Reserves	**196**	**386**	**214**	**155**

*** OCS Disputes the accuracy of the Company calculations.**

Q. DO YOU HAVE ANY FINAL COMMENTS REGARDING THIS ISSUE?

A. I recommend that the Commission reject the Company's inputs and accept the proposed adjustment, shown on Table 1, which will exceed the Company's overstated actual 2010 reserve figures, as detailed above.

<u>Adjustment 3: Non-Owned Wind Reserves Variable Cost</u>

Q. HAS THE COMPANY INCLUDED NON-OWNED WIND PROJECTS IN THE TEST YEAR?

A. Yes. While I do not agree with the Company's methodology, they did attempt to incorporate the additional integration requirements for its non-owned wind projects. This increased the amount of wind integrated into the system by more than [redacted] MW for PACE and [redacted] MW for PACW.[13] This produced an [redacted] MWH of wind energy requiring integration in the test year.[14] Based on Mr. Duvall's calculation of test year intra-hour wind integration costs, this produces more than $2.6 million of additional NPC included in the test year. The proposed adjustment removes these costs.

Q. EXPLAIN THE BASIS FOR THIS ADJUSTMENT.

A. The Company is not, as they should be, compensated for these costs by the wholesale transmission customers who are responsible for them. Effectively, the Company's methodology requires retail customers to subsidize wholesale customers. For many years the Company has expected it would encounter substantial wind integration costs, yet it

[13] 700-23\C.8 Confidential\Attach R746-700-23.C8-1, file Utah 12w_Wind (Confidential).xls
[14] Attachment R746-700-23.C1-3 Confidential

has failed to request recovery of these costs in a timely manner from the appropriate parties. This amounts to regulatory negligence.

Q. THE COMPANY HAS NOW REQUESTED RECOVERY OF SOME COSTS FROM NON-OWNED WIND FARMS AS PART OF ITS PENDING FERC RATE CASE. THE COMPANY PROPOSES A DEFERRAL MECHANISM TO CREDIT CUSTOMERS WITH THE REVENUES SO RECOVERED. IS THIS A SATISFACTORY SOLUTION?

A. No. The FERC tariff proposal made by the Company in the FERC proceeding is intended to only recover fixed costs associated with wind integration services. The Company has made no proposal at the FERC to recover variable production costs associated with wind integration.[15] The FERC tariff will only recover the same kind of fixed costs retail ratepayers are already paying for: return on investment and fixed O&M for power plants used to provide wind integration services. It does not even attempt to recover the variable costs (as modeled in GRID) associated with integration of non-owned wind farms. I recommend the Commission disallow recovery of the variable non-owned wind farm costs in the test year by adopting the proposed adjustment.

Q. THE COMPANY CONTENDS THAT THE FERC IS NOT ALLOWING RECOVERY OF VARIABLE COSTS OF WIND INTEGRATION UNTIL IT COMPLETES A RULEMAKING PROCESS. IS THIS A VALID JUSTIFICATION FOR CHARGING RETAIL CUSTOMERS WITH WHOLESALE SERVICE COSTS?

A. No. Had the Company raised this issue earlier, perhaps by now a resolution would have been achieved. The Company should not be rewarded for its lack of diligence at the FERC by being allowed to overcharge retail customers. Regulators in both Idaho and Washington recently denied recovery of these costs in base rates.[16] Regulators in Idaho have further stated they will not allow wind integration costs related to serving these wholesale customers to be recovered via their EBA, a mechanism comparable to the Utah

[15] OCS DRs 2.19 and 2.20.

[16] Idaho Public Utilities Commission Docket No. PAC-E-10-07, Order 32196, Page 30. Washington Utilities and Transportation Commission ("WUTC") Docket No. UE-100749, Order No. 6, paragraph 125, page 48.

EBA.[17] Under the Company's logic, ratepayers in Utah would be responsible for costs associated with the unrecovered integration costs for transmission customers denied recovery in Washington and Idaho as well.

Q. WOULD THIS ADJUSTMENT BE THE SAME IF THE PROPOSED RESERVE REQUIREMENT ADJUSTMENT (NO. 2 ABOVE) IS ACCEPTED?

A. No. In that case, this wind integration cost adjustment should be reduced because the total amount of reserve costs included in the test year has been reduced. I have included this offset in the Final Balancing Adjustment described below.

C. GRID Commitment Logic and Start-Up Costs

Adjustments 4 and 5: Currant Creek and Gadsby CT Screens

Q. PLEASE PROVIDE SOME BACKGROUND CONCERNING THIS ISSUE.

A. Absent user-supplied workarounds, the internal logic of GRID frequently fails to utilize the least cost schedule for gas-fired resources, meaning that there are many hours when gas-fired generators fail to operate economically within the model. This error in turn has a spillover effect on how coal-fired generation is modeled because the uneconomic operation of gas plants forces lower cost coal units to have their output curtailed, raising net power costs in the GRID model.

Q. DID THE COMPANY ATTEMPT TO ADDRESS THIS PROBLEM IN GRID?

A. Yes. Mr. Duvall has included a "screening adjustment" in order to correct the scheduling error. I reviewed the Company's workpapers and compared the results they derived with those from my own screening models. I am satisfied with the Company's methodology insofar as it has been applied.

Q. DID THE COMPANY APPLY ITS SCREENING METHODOLOGY TO ALL OF ITS GAS RESOURCES?

A. No. The Company did not apply screens to the Currant Creek plant because it is modeled as a "must run" plant. Further, Mr. Duvall states that the Gadsby CTs are no longer

[17] Idaho Public Utilities Commission Docket No. PAC-E-10-07, Order 32196, Page 30.

modeled as must run at night, which he asserts addresses an adjustment OCS proposed in the last case. However, he failed to disclose that, aside from planned outages, his modeling requires the Gadsby CTs to run every single day, whether needed, economical or not. This assumption is unfounded.

Q. DO ACTUAL OPERATIONS SUPPORT THE ASSUMED MUST RUN DESIGNATIONS FOR CURRANT CREEK AND DAILY OPERATION OF THE GADSBY CTS?

A. No. Currant Creek is really two independent units, which can cycle together or separately. While the number of instances when both units are shut down at night has been declining, there are still a substantial number of nights when at least one of the units is shut down. Confidential Table 3 below shows the number of starts for each Currant Creek unit for 2011.

For the Gadsby CTs, there is no support for the assumption that these units must run every single day. As Table 3 below shows, the units continue to have many days when they do not operate at all. This is likely to be further intensified with the addition of the West Valley resources in the test year.

[redacted]

Q. HOW DO YOU RECOMMEND THESE UNITS BE MODELED?

A. I have modeled Currant Creek as two independent, but identical units. It is worth noting that the Company itself models Hermiston as two independent units. There is no reason the same should not be done for Currant Creek, a larger plant. I model one unit as a must run, while the other is allowed to cycle. For the Gadsby CTs, I model allowing them to run, or not, as dictated by economics. The screening adjustments for the Gadsby CTs and Currant Creek are presented on Table 1.

Q. IN PRIOR CASES, MR. DUVALL HAS SUGGESTED THAT REMOVING THE MUST RUN DESIGNATION FROM SOME OF THE UNITS MAY RESULT IN THE COMPANY EXPERIENCING RESERVE SHORTAGES. PLEASE ADDRESS THIS CONCERN.

A. This problem could be addressed in developing the screens. However, Mr. Duvall exaggerates the significance of the problem. In GRID, PACE has no serious reserve shortage problem. In the Company base case, there are only [redacted] MWH of reserve shortages in the test year. Even without the Gadsby CTs, the reserve shortage would only be [redacted] MWH.[18] Using the price for reserve capacity assumed in the Company's West Valley analysis [redacted])[19] would result in an increase in cost of [redacted] - a negligible amount. Actual purchase prices paid by the Company for reserves are even lower, [redacted].[20] To put this in the proper context, the GRID model predicts reserve shortages of more than [redacted] for PACW, an issue about which the Company apparently is unconcerned. Clearly, whether the Gadsby CTs are modeled as must run units does not materially impact the issue of whether there is enough reserve capacity allocated in GRID.

Since it is unlikely the screening will remove the Gadsby CTs from every hour when a reserve shortage might occur, the ultimate impact would be far less. While it might be a good idea to reflect reserve shortages costs in the GRID model (they are not modeled now), many of the other adjustments I propose would reduce the reserve shortages. Consequently, I do not believe it is necessary to reflect the impacts of reserve shortages in connection with the correction of the treatment of Gadsby CTs.

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[18] These figures are all based on the Company's overstated reserve requirements.
[19] Confidential Attachment OCS DR 2.33-1. File: West Valley - GRID Analysis CONF.xlsx.
[20] OCS DR 21.1h

<u>Adjustment 6: Lake Side Start-Up Cost</u>

Q. HOW IS THE START-UP O&M VARIABLE USED IN GRID?

A. This input reflects additional O&M costs that occur when a unit is started up. Start up O&M is not used directly in computing NPC because it is not included in the accounts that comprise NPC. However, it indirectly impacts NPC because it controls how often combined cycle plants can start or stop. In the case of Lake Side, the Company recently doubled this input. Higher start-up costs result in fewer starts or stops for the unit and less efficient operation overall. If start costs are high then the unit may run overnight, even if its output costs more than market purchases. These high start costs modeled by the Company result in a substantial reduction in the number of starts in the test year, as compared to actual operation as is shown in Figure 1, below. The historical data, however, shows start-ups for Lake Side are not being reduced nearly as much as assumed in the test year. In fact, for Calendar Year 2011, the total number of starts for the Lake Side CTs was [redacted], compared to [redacted] in the test year or [redacted] for the 12 months ended June 30, 2011.

[redacted]

Q. DOES THE COMPANY PROVIDE ANY SUPPORT FOR THE LEVEL OF START-UP O&M IT ASSUMES FOR LAKE SIDE?

A. Not really. In OCS DR 2.26, I requested all documents used to develop the "Additional Start-Up O&M" costs used in GRID. The Company referred to the workpapers provided with the filing requirements.[21] This document provides only a calculation of test year figures based on undocumented per start costs from 2008. In the end, the Company has provided no support for the figures it actually uses for Lake Side start up O&M in simulating NPC in this case.

On their face, the start-up costs used appear unreasonable because they produce start up costs that, by themselves, exceed the entire actual total O&M for the Lake Side plant. When the per start costs are multiplied by the number of starts each quarter from July 2007 to June 2011, they equal 106% of the total O&M for Lake Side during the period. Since power plant O&M contains many costs unrelated to the number of starts (such as wages, supplies, replacement parts, and the like), it is quite apparent the Company has overstated these costs in GRID.

Q. DOES THE COMPANY REFLECT O&M SAVINGS DUE TO THE DECLINE IN STARTS ELSEWHERE IN THE TEST YEAR REVENUE REQUIREMENTS?

A No.[22] In effect, the Company is penalizing the dispatch of Lake Side in the test year on the basis of a hypothetical start-up cost, but it does not make any adjustment to reflect the benefit of the reduced number of starts in the determination of test year O&M.

Q. HAVE YOU PERFORMED ANY ANALYSIS TO DETERMINE WHETHER THERE IS A VALID RELATIONSHIP BETWEEN ACTUAL O&M EXPENSES AND THE NUMBER OF STARTS FOR LAKE SIDE?

A. Yes. I obtained monthly start-ups and O&M expense for the Company's combined cycle plants.[23] I examined a number of regression models, and found that no valid statistical relationship exists between the number of starts and monthly O&M expenses for Lake

[21] R746-700-23.C.8 -1UTGRC12w_Startup Attributes (Confidential).xlsx"
[22] OCS DR 2.114
[23] OCS DR 21.1e OCS 21.1 g Confidential Attachment.

Side. For example, a regression comparing monthly O&M to monthly starts had an R-Squared of only .14 and the sign was *negative* (the opposite of what the Company is assuming). Quarterly data showed even less significant results. Because the Company has not supported the higher level of start-up O&M costs, I have proposed an adjustment that removes the start-up O&M input from the determination of the screen used for Lake Side and is quantified in Table 1.

D. Long-Term Contract Adjustments

Adjustments 7-9: SMUD, BHP and UMPA II Shaping

Q. WHAT IS A CALL OPTION CONTRACT?

A. Call option contracts allow the purchaser the right to pre-schedule energy deliveries based on expected market prices and/or the purchasers' requirements. The Company models several "call option sales" contracts including Black Hills Power, the Sacramento Municipal Utility District, and Utah Municipal Power Agency. Since the Commission's decision in the 2007 GRC, modeling of the SMUD contract is based on a monthly allocation of contract energy based on historical usage patterns.[24]

Q. DID THE COMPANY CORRECTLY IMPLEMENT THE COMMISSION APPROVED SMUD MODELING?

A. No. The Company acknowledged an error in the calculation of monthly energy for SMUD.[25] My proposed SMUD Adjustment implements this correction. The Company did implement this correction in the May 11, 2012 NPC Update. This has been accounted for in the overlap adjustment.

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. Typically, in GRID the Company schedules the contract energy during

[24] August 11, 2008 Report and Order, Utah Public Service Commission Docket No. 07-035-93, page 23.
[25] OCS DR 2.29

the highest cost hours allowed for the specified period. SMUD was the most significant contract as regards this type of modeling. The Commission rejected the Company approach for modeling SMUD in the 2007 case as noted above. However, the Company applies the same methodology to the BHP and UMPA II contracts.

Q. IS THE COMPANY'S MODELING REALISTIC?

A. No**,** the contracts simply aren't used in the way the Company models them. Generally, for many reasons, counterparties use these resources in a manner that is far less costly than assumed by the Company in GRID. First, the counterparty is not using the same forward price curves as the Company. The counterparty presumably has no knowledge of the Company's forward price curves and may not even be in the same markets as assumed by the Company. Differences in delivery location, transmission constraints, availability of the counterparties' own generation, and many other factors will drive decisions regarding use of the available energy. In the end, the counterparty is interested in serving its own customers at the least possible cost (subject to its own constraints) rather than maximizing the cost to PacifiCorp. The Company's approach does not represent "normalization" of the contract impacts on NPC, but rather the worst possible outcome.

Q. WHAT IS YOUR RECOMMENDATION?

A. For the BHP contract, I recommend use of a simple flat profile as this is consistent with historical usage patterns. For UMPA, I use a flatter profile as well, supported by historical data. In both cases, the modeling better represents the historical data and provides more realistic modeling results. The adjustments reflecting these profiles are included in Table 1.

<u>Adjustment 10: Arizona Public Service ("APS") Contract Modeling</u>

Q. PLEASE EXPLAIN THE SUPPLEMENTAL OPTIONS IN THE APS CONTRACT.

A. Under these options, APS is required to offer the Company [redacted] GWH per year from surplus coal generation and [redacted] GWH of "Other" surplus energy per year, at the time of APS's choosing, but at a price governed by specific formulae in the contract. Generally, the coal surplus is priced somewhat above the incremental cost of coal generation, while the Supplemental Other surplus is priced somewhat above the cost of gas generation. While APS must offer the energy, PacifiCorp is under no obligation to take it. Consequently, it only makes sense for the Company to do so if the energy is economic.

Q. HOW DOES THE COMPANY MODEL THESE CONTRACT OPTIONS?

A. The Company models a simple monthly screen for these two resources and optimizes the use of the two options (which can't be used simultaneously) independent from each other, but restricts the time period when the energy can be used from each contract. The Company's modeling of these resources produces very strange results. Under the Company modeling, all of the energy from the APS Coal option is assumed to be used at either 5 AM or 10 PM, but no other hours. These do not seem like hours where it would be useful to use this contract.

The Company is now using daily screens for thermal units. There is no reason to not do so with these APS contract options as well. The proposed adjustment implements a correction to produce a more realistic modeling by selecting the most economic option for each Heavy Load Hour ("HLH") or Light Load Hour ("LLH") period of each day.

<u>Adjustment 11: Biomass Contract</u>

Q. PLEASE DISCUSS THE OREGON BIOMASS QF CONTRACT.

A. The Company proposes to include the new Biomass contract in its April NPC update. Biomass is the same project which had a very long term contract with the Company well in excess of the Company's avoided costs during most of the past decade. That contract expired and was replaced with a new one.

Q. HOW WAS THE PRICING FOR THE NEW BIOMASS CONTRACT DETERMINED?

A. This QF is located in Oregon. Under OPUC rules, prices for QFs smaller than 10 MW are based on Schedule 37, an approved tariff. For larger QFs, such as Biomass, another approved tariff, Schedule 38, governs the pricing. Schedule 38 specifies how the prices from Schedule 37 should be adjusted to address the unique characteristics of larger QFs. I have attached these tariffs as Exhibit OCS 4.3D. There are several factors that govern the final price, and adjustments are considered, as appropriate, for dispatchability, reliability, fossil fuel risk, and line losses.

Q. DID THE COMPANY MAKE ADJUSTMENTS TO THE SCHEDULE 37 PRICES TO DEVELOP THE PRICES FOR THE BIOMASS CONTRACT?

A. Yes. Confidential Table 4[26] below shows the pricing adjustments made by the Company in its determination of the final prices paid. Notably absent is any adjustment related to dispatchability. Based on the Schedule 38, a downward adjustment should be made if the project does not provide the dispatchability benefits of the proxy plant, which in the Oregon methodology is a gas-fired combined cycle unit.

[26] Source: Confidential Attachment OCS DR 16.1-2 Attachment WIEC 21.12.

[redacted]

Q. HAS THE OPUC ACTUALLY APPROVED THE BIOMASS CONTRACT?

A. No. Oregon practice does not require approval of QF contracts. Instead parties may challenge contracts when presented in a rate case. There is no basis to assume the new Biomass contract has received any OPUC approval at this time.

Q. IS THE BIOMASS CONTRACT DISPATCHABLE AS COMPARED TO THE PROXY COMBINED CYCLE PLANT?

A. No. While the Company alleges that the Biomass plant demonstrated the ability to ramp the plant up or down on an hour-ahead basis,[27] the Biomass contract has no provision that allows economic curtailment.[28] However, a combined cycle plant could provide ready reserves, spinning reserves, intra-hour, and hourly dispatchability. Biomass possesses none of these capabilities.[29] Further, the contract has no annual limit on the amount of energy Biomass can deliver to the Company.[30] Clearly an adjustment was necessary to account for the lack of dispatchability of the project relative to a combined cycle plant,

[27] OCS DR 16.1, Attachment WIEC 21.13
[28] OCS DR 16.1, Attachments WIEC 33.27 and 33.28. The Contract allows only for transmission contingencies, a common feature of this type of contract.
[29] OCS DR 16.1, Attachments WIEC 21.16, 21.17, 21.18 and 21.19.
[30] WIEC 21.20. 13 (Non confidential data response, Wyoming Docket No. 20000-405-ER-11).

but the Company failed to make such an adjustment. This is a substantial benefit of a combined cycle plant and the lack of dispatchability should produce a sizable reduction to the prices paid for Biomass.

Q. HAVE YOU QUANTIFIED THE VALUE OF DISPATCHABILITY?

A. Yes. The Oregon tariffs do not specify how the Company is to determine the dispatchability adjustment. Consequently, I obtained the PacifiCorp GRID model used for avoided cost studies circa mid-2011.[31] This model is representative of information available to the Company around the time of the Biomass negotiation. Therefore, it provides a reasonable basis to determine the benefits of dispatchability of a combined cycle plant. I compared the NPC difference between the Company's base case scenario and one where Hermiston Unit 1 could not be dispatched or provide reserves. I levelized the unitized difference (NPC/MWH) over the 15-year term of the Biomass contract. I used this result to determine the reduction required for the Biomass contract. Table 1 shows the resulting adjustment. Finally, the Company's update reflects a non-generation agreement with Biomass that reduces the impact of this adjustment. This has been reflected in the overlap adjustment.

E. Hydro Logic and Inputs

Adjustment 12: Merwin Reserve Capability

Q. EXPLAIN THE BASIS FOR THIS ADJUSTMENT.

A. In the test year, the Company assumed no reserve capability for the Merwin plant. However, the Company does admit that Merwin can provide reserves in certain circumstances[32] and even counted those reserves in the various analyses of actual 2010 reserves I discussed earlier in the context of the wind integration issue. Based on the data

[31] OCS DR 16.-2, Confidential, Attachment WIEC 9.4.
[32] WIEC 10.5. - Non confidential data response, Wyoming Docket No. 20000-405-ER-11.

provided by the Company, Merwin provided reserves for more than [redacted] hours from July 1, 2007, through June 30, 2011. This amounts to approximately [redacted] of the total hours in that period. During this period it provided on average [redacted] of reserve capability. The proposed adjustment includes this average level of reserves in GRID.

<u>Weekly v. Hourly Hydro Shaping</u>

Q. HAS THE COMPANY RECENTLY CHANGED ITS MODELING OF THE HYDRO RESOURCE IN GRID?

A. Yes. For several years, the Company used GRID's internal logic to develop the optimal hourly shape for hydro based on input weekly hydro energy. The weekly energy was derived from a model called Vista. The Vista model is used within the Company for various applications related to hydro modeling. However, in the most recent GRC, the Company used Vista to develop the optimal hourly dispatch bypassing the GRID weekly shaping logic. In the present case, the Company has reverted back to the prior modeling where Vista develops a weekly hydro energy allocation and then GRID is used to develop the hourly hydro shapes. The Company changed back to the prior modeling without performing any analysis to determine the impact of the change and without any workpapers supporting the reserve allocation assumptions.[33] The Company contends this adjustment was made to address an OCS' adjustment in the prior case, related to co-optimization of hydro generation and reserve allocations. However, the Company's modeling does nothing specific to address that issue. Further, by moving back and forth between the weekly and hourly Vista modeling it raises the concern that the Company may be doing so in an opportunistic manner. I recommend that the Commission require the Company to present the results of both modeling methods in the next case and justify the selection of the method used.

[33] OCS DR 2.15 and 2.16.

<u>Adjustments 13-14: Correct Lewis River Efficiency Loss</u>

Q. WHAT IS THE LEWIS RIVER LOSS OF EFFICIENCY ADJUSTMENT IN GRID?

A. The Company contends that whatever modeling method used in GRID (whether based on hourly or weekly Vista inputs) there is an overstatement of hydro energy because they believe that Vista only models hydro units as being operated at their most efficient loading point. Consequently, they model a transaction which removes this “extra” energy.

Q. ARE THERE PROBLEMS WITH THE LOSS OF EFFICIENCY ADJUSTMENT?

A. Yes. The Company computes the Lewis River Efficiency loss of efficiency adjustment based on actual data for the 12 months ended June 30, 2011. The method compares an assumed efficiency from the Vista model to actual generation. However, the assumption made in that analysis is that Vista simply turns the hydro units on and off, loading them at their most efficient point when running. In reality, Vista actually varies the hydro output substantially from the most efficient output level. Consequently, the difference between the actual efficiency and the efficiency assumed in Vista is less than the Company assumes in the development of the efficiency loss adjustment. Finally, the historical period used by the Company had 12% more hydro generation than the test year, so the Company’s method overstates the impact of the adjustment under normalized hydro conditions.

Q. HAS THE COMPANY APPLIED THIS ADJUSTMENT IN AN EQUITABLE MANNER WHEN CONSIDERING BOTH HYDRO AND THERMAL RESOURCES?

A. No. The Company’s underlying premise is that the Vista model assumes normalized generation from the Lewis River plants would always take place at the most efficient loading. Consequently, the Company assumes that there is more hydro energy in the test year than would be the case under actual conditions. However, for thermal plants the opposite is true. For example, gas units are nearly always modeled in GRID at their *least* efficient loading levels, thus producing less energy per unit of fuel than actually occurs. These two situations are mirror images of the same problem (normalized generation patterns differing from actual, resulting in a difference between normalized and actual efficiency). However, the Company has only addressed the problem related to hydro modeling, while ignoring the same problem with modeling of thermal plants. If the efficiency loss adjustment is modeled for Lewis River, an offsetting efficiency gain adjustment should be modeled for thermal units.

Q. WHAT WOULD BE THE OUTCOME IF A THERMAL EFFICIENCY GAIN ADJUSTMENT WERE MODELED?

A. It would substantially reduce NPC, even with the Company's efficiency loss adjustment. I will demonstrate later that the cost of fuel as modeled in GRID is $11.4 million higher than would occur if the overstatement of heat rates in GRID were eliminated. Some, but not all, of this problem is corrected by an OCS subsequent adjustment.

Q. WHAT IS YOUR RECOMMENDATION?

A. Unless the Company fairly implements all of the necessary adjustments to cure the inequities in the hydro modeling, it should not include any adjustments. My primary recommendation is to simply remove the Company's Lewis River loss of efficiency adjustment. However, if the Commission does allow the inclusion of the Company's Lewis River loss of efficiency adjustment, it should at least make the correction discussed above. Note that there is an overlap between the two adjustments referenced in this section, which is eliminated in the Final Balancing Adjustment.

<u>Adjustment 15: Hydro Forced Outage Rates</u>

Q. DOES THE COMPANY MODEL HYDRO FORCED OUTAGES IN GRID?

A. Yes. For run of river units, forced outages are factored into the annual energy production. For hydro with storage the Company makes assumptions about when outages might occur based on historical outages and simply removes a certain number of days of hydro generation from the Vista model results.[34] The Company effectively models hydro forced outages as if they were planned outages and known in advance and all the energy is lost for all time.

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

A. No. For storage hydro the primary effect of forced outages is to impact the timing rather than the amount of hydro energy that may be produced. This occurs because energy may be stored and used at a later time or simply flow through another turbine at the same plant.

Q. IS ANY OF THE HYDRO ENERGY LOST DUE TO SPILLAGE DURING FORCED OUTAGES?

A. Yes, however, for 2011, the Company can only document loss of [redacted] MWH due to spillage.[35] This is less than 20 percent of the hydro energy the Company assumes will be lost due to forced outages in the test year.

Q. HAS THE COMPANY PROVIDED ACTUAL DATA SHOWING THE AMOUNT OF HYDRO ENERGY BEING SPILLED FOR THE FOUR-YEAR PERIOD USED TO DERIVE THE HYDRO OUTAGE ASSUMPTIONS?

A. No. The Company only began keeping detailed records of hydro energy lost due to spillage in 2011. Based on the 2011 data,[36] there was far less spillage than the Company estimates based on the outage rates it models. In fact, the Lewis River and Toketee hydro units [redacted] energy lost due to forced outages (none for Lewis River and [redacted] MWH for Toketee).

[34] See Docket No. 10-035-124, OCS DRs 20.7, 20.8 and 20.9. Non Confidential Data Responses. The Company's modeling has not changed since last year's case.
[35] See OCS DR 2.74
[36] OCS DR 2.74

Q. HOW DO YOU RECOMMEND THE COMMISSION ADDRESS THIS ISSUE?

A. The proposed adjustment provides corrections to the Company's test year based on a more reasonable modeling of hydro outage rates. I removed all of the forced outage energy lost at the Lewis River and Toketee projects, but retained the forced outages for the other projects. This results in approximately the same lost energy in the test year as in the 2011 data. This approach is reasonable for purposes of this case, but should be improved upon in future cases. I recommend that the Company be required to develop a methodology based on use of the data provided in OCS DR 2.74 to produce hydro outage inputs. The modeling should not be based on removal of hydro generation at specific times, but rather should be based on an equal loss across the year. This is necessary because hydro, like thermal outages occurs at random times.

Q. HAS THIS ISSUE BEEN CONSIDERED IN OTHER PROCEEDINGS ELSEWHWERE?

A. Yes. This issue was explored in various workshops and filings in Oregon Docket No. UM 1355. In that case, the Company agreed that for storage units forced outages were random,[37] would not necessarily result in a loss of energy,[38] and that there was no industry standard for modeling hydro forced outage rates.[39] The Company ended up withdrawing its modeling of hydro forced outage rates in its supplemental testimony.[40] The methodology the Company uses in this case is more onerous than the modeling proposed in Oregon because it assumes all of the energy lost due to forced outages is spilled, while in the prior cases it assumes some of it was rescheduled.[41]

[37]OPUC Docket No. UM 1355, PPL/200, Smith/3
[38]Id at 2
[39]Id at 7
[40]OPUC Docket No. UM 1355, PPL/405, Duvall/23
[41]See Docket No. 10-035-124, See OCS 20.9

F. Transmission Issues

Adjustments 16 and 17: DC Intertie Transmission Cost and Centralia Point to Point Contract

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

A. This contract is used to import purchases from the Nevada Oregon Border ("NOB") to West Main.[42] The Company does not model any long term contracts requiring the DC Intertie, but does model short term balancing transactions enabled by the contract.[43] Typically those transactions are the last resources used by the Company and the Company has stated previously that it is unlikely that under normalized conditions any such purchases would be made.[44] In the test year the NPC benefits of the NOB/Central Oregon transactions are inconsequential – less than 1.5% of the DC Intertie contract cost.

Q. WHAT WAS THE ORIGINAL PURPOSE OF THIS CONTRACT?

A. Originally the DC Intertie could be used to deliver power associated with the Southern Cal Edison ("SCE") wholesale power contract initiated in 1994. However, that contract expired long ago, and the Company has not undertaken any steps to determine if there are options available to renegotiate, modify, terminate, or buy out of the DC Intertie transmission contract.[45]

Q. EXPLAIN THE ORIGINAL PURPOSE OF THE CENTRALIA POINT TO POINT CONTRACT.

A. The original purpose of this contract was to wheel energy from the Centralia power station to PacifiCorp load centers. However, the Company's contracts for purchase of energy from Centralia ended in 2010. There are no forward transactions modeled in the test year that require utilization of this resource.[46] The Company has not provided any

[42] R746-700 CD Confidential\700-23\C.8 Confidential\Attach R746-700-23.C8-1, UTGRC12w_Wheeling.
[43] OCS DR 2.92
[44] WUTC Docket No. UE-100749, Response to ICNU DR 10.3. (Provided in Response to OCS DR 2.102)
[45] Docket No. 20000-384-ER-10, WIEC 1.73. (Provided in Response to OCS DR 2.102)
[46] OCS DR 2.91.

documentation supporting the reasons why it failed to coordinate the termination date of the contract with the termination of the Centralia purchases even though the issue has been raised in several cases in the past few years.

Q. WHAT IS YOUR RECOMMENDATION?

A. The DC Intertie and Centralia Point to Point contracts are quite similar. In both cases, the contracts were originally intended to enable specific wholesale transactions that have now expired. The Company cannot identify any long term transactions in the test year which require these resources and the short-term benefits are inconsequential. In the case of the DC Intertie, the Company only began to model NOB transactions after parties pointed out the lack of justification for the contract costs. These contracts should be removed from the test year because it is unreasonable to charge customers for costs that provide almost no corresponding benefits. Further, the imprudence of the Company's inaction related to these contracts should be considered. In the case of the DC Intertie, signing what amounts to a nearly perpetual contract was of questionable prudence.

If, in actual operation in the future, these contracts provide compensating benefits, the Company could recover some of the costs via the EBA. Finally, the Centralia contract is only in the test year for the month of June, 2012 and then expires. The Company has not replaced the contract, confirming that it is completely unnecessary.

Q. HAS THE COMPANY ATTEMPTED TO SELL THE RIGHTS OR FIND OTHER USES FOR EITHER OF THESE CONTRACTS?

A. The Company has made some efforts to sell the Centralia rights or redirect it to more useful paths.[47] However, the value derived is much less than the cost of the contract. The Company has included an adjustment in its update to offset NPC with the revenues

[47] OCS DR 2.91

associated with the sale of the contract rights. This is reflected in OCS Final Balancing Adjustment. No such efforts have been made relative to the DC Intertie contract.[48]

Q. HAVE REGULATORS IN OTHER STATES ADDRESSED THIS ISSUE?

A. Yes. In WUTC Docket UE-100749, Washington regulators disallowed the costs of the DC Intertie contract on the basis that:

> PacifiCorp's evidence and arguments focus on whether the contract was prudent when it was executed. However, we do not need to answer that question in this Order. Even if we assume that the contract was prudent at its inception the Company has an ongoing obligation to manage the resource under contract to provide a benefit to the Company and its ratepayers. PacifiCorp has failed to demonstrate that it does so.[49]
>
> ****
>
> If the contract is not being used by the Company, it has an obligation to market its available transmission capacity in an effort to recover some of its costs. The Company proffers no testimony along this line. For these reasons, we conclude that PacifiCorp failed to demonstrate that the DC intertie contract would provide benefits to Washington ratepayers during the rate year. Therefore, we adopt the adjustments presented by Staff and ICNU and reduce NPC expense by $1,057,130.[50]

<u>Adjustment 18: Dynamic Overlay</u>

Q. WHAT IS DYNAMIC OVERLAY?

A. The Company has a [redacted] MW contract with Idaho power that allows it to transfer energy from PACE to PACW, or reserves in either direction between PACE and PACW.[51] In GRID, the Company only models the transfer of reserves from PACW to PACE. However, the contract can be dynamically scheduled meaning the most optimal mode of operation can be selected during actual operation. Consequently, the Company is not reflecting the full value of the contract in the GRID model. In actual practice there are

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[48] Utah Docket No. 10-035-124, UIEC 14.7. (Provided in response to OCS DR 2.102)

[49] WUTC Docket No. UE-100749, Order No. 6, paragraph 148, page 55. Note that the Centralia contract was not at issue in Washington.

[50] Id. at paragraph 152, page 56.

[51] WIEC 21.23.Provided in response to OCS 16.1

far more deliveries of reserves from PACE to PACW than the reverse situation, which is the only direction modeled in GRID.

Q. PACW OFTEN HAS A SURPLUS OF RESERVES FROM HYDRO. ORDINARILY SPINNING RESERVES ARE TRANSFERRED FROM PACW TO PACE. WHEN WOULD OTHER MODES OF OPERATION BE MORE USEFUL?

A. In some cases energy may be lower cost in PACE than PACW while PACE does not need reserves. In such cases, a transfer of energy would be more economical. While PACW has a surplus of spinning reserves, at times GRID shows a shortage of ready reserves. In such cases spinning reserves are used for ready reserves. This amounts to substituting a higher value resource for a lower value one. PACE generally has a large surplus of ready reserves. Consequently, there may be times when it is preferable to transfer ready reserves from PACE to PACW.

Q. HOW DID YOU MODEL THIS SITUATION?

A. I performed three GRID runs. The Company base run, a PACE to PACW energy transfer only run, and a run modeling a PACE to PACW ready reserve transfer. The most optimal mode of operation was then selected on an hourly basis. This adjustment, shown on Table 1, reflects the value of this enhanced modeling.

Q. IN HIS RECENT WYOMING REBUTTAL TESTIMONY, MR. DUVALL CRITICIZED THIS ADJUSTMENT ON THE BASIS THAT IT SUBSTITUTES READY (TEN MINUTE) RESERVES FOR SPINNING RESERVES IN THE PACE TO PACW TRANSFER. IS THIS A FAIR CRITICISM?

A. No. The PACE to PACW reserve transfer supplies ready reserves from PACE to meet the ready reserve requirement in PACW. Because PACW has a ready reserve shortfall in some hours the requirement is being met by spinning reserves without the transfer. This is unnecessary and quite inefficient, much like supplying a car designed to run on regular gasoline, with premium.

<u>Adjustment 19: Transmission Losses</u>

Q. HOW DID THE COMPANY DETERMINE LOSS FACTORS IN GRID?

A. The Company used a simple five-year average of annual calendar year losses from January 2006 through December 2010. However, recent transmission investments have been quite substantial and, as a result, losses have been declining. By the time the filing was made data for a more recent five-year period should have been available to the Company. In discovery I obtained the five-year average data for the period January 1, 2007-December 31, 2011. Customers should receive the benefits of the recent transmission investments by including reduction in losses. The proposed adjustment reflects the value of the reduced losses in the test year.

Q. HAS THE COMPANY PROPOSED TO UPDATE LOSSES IN THIS CASE?

A. No. While Mr. Duvall proposes various updates, he did not include an update to losses. Nor did the Company even use the most recent data available at the time of the filing.

<u>Adjustment 20: Non-Firm Transmission</u>

Q. PLEASE PROVIDE AN OVERVIEW OF TRANSMISSION MODELING IN GRID.

A. GRID provides a number of options for modeling transmission. The Company has defined a number of transmission areas in GRID, and models contractual transmission paths, called links, between these areas which allow for the transfer of power. Generally speaking, increasing transmission capacity improves the efficiency of operations as it allows for more economic purchases and sales to be made, as well as a more efficient dispatch of system resources.

Modeling of transmission links in GRID allows for pricing of the transmission path either on the basis of fixed costs for contracts, or on a volumetric basis (i.e. per KWH transferred.) When volumetric pricing is used, the price is considered in determining whether transactions between areas should be made. This is standard industry practice. There are more than 130 transmission links modeled in GRID. For long term contracts, the Company normally models the cost and capacity of the contract based on the most recent historical year values. There are some instances where the Company makes pro-forma adjustments to reflect known changes to either the contract cost or capacity. For non-firm and Short Term Firm transmission the Company doesn't use the same method as it applies for its long term contracts.

Q. HAS THE COMPANY FOLLOWED THE COMMISSION APPROVED METHODOLOGY FOR MODELING NON-FIRM TRANSMISSION?

A. No. In the 2009 case the Company used a four-year average of non-firm transmission capacity and costs priced on a volumetric (per KWH) basis. This was first required by the Commission in Docket No. 07-035-23.[52]

In the current case, the Company combined the modeling of Short-Term Firm ("STF") and non-firm transmission. The capacity of STF and non-firm transmission links are based on a four-year average while modeling the cost is based on the most recent historical year (the twelve months ended June 30, 2011). The Company provides no justification for this change in modeling from its position in the most recent fully litigated case.

Consequently, there is a complete mismatch between the test year costs and the capacity of STF and non-firm transmission. The Company lumps these two types of resources together, as if they were identical products. In the 2010 Utah case, the

[52]Final Order Docket 07-035-93, page 107.

Company asserted that there was a similarity in the way the Company purchases and uses non-firm and short-term firm transmission in support of this modeling method.

However, there is a substantial difference between non-firm and STF transmission. STF transmission may be purchased well in advance and can be counted on for reliability purposes. Non-firm transmission can be cut off for reliability purposes by the supplier. Consequently, the only value of non-firm is for economy purposes. Non-firm transmission certainly cannot be counted on for serving load. Under the Company modeling this fact is ignored. There are also some important differences in how non-firm and STF transmission is purchased. The primary difference is that STF transmission is generally purchased with much more lead time than non-firm transmission and may be priced on a daily or even monthly basis, while non-firm transmission is almost exclusively priced on an hourly volumetric basis.

The Company acknowledged in a recent discovery response that the major reason for non-firm purchases was for economy interchange and that such transactions are normally executed shortly before utilization.[53] As a result, in these instances the Company can easily evaluate the cost and benefit of the non-firm transmission ahead of the time trades are made.

Q. PLEASE ELABORATE ON THE NON-FIRM AND STF TRANSMISSION MODELING USED IN GRID.

A. The Company has applied the Commission approved methodology for STF transmission,[54] but expanded it to include non-firm transmission. The STF method was never approved by the Commission for non-firm, and differs from the method approved by the Commission as applied by the Company in the last fully litigated proceeding, as discussed above.

[53] See Idaho PUC Docket No. PAC-E-10-07, Response to PIIC 126 and 127, Non Confidential Data Responses.
[54] Docket No. 09-023-35, Final Order, page 41.

The Company's methodology assumes that STF transmission is the more important product purchased, which is not a valid assumption. In fact, far more non-firm purchases are made than STF purchases. This can be seen from the test year costs for purchases of each product. In the test year (based on the 12 months ended June 30, 2011) the Company purchases [redacted] million[55] of STF and non-firm transmission. Of this amount, more than [redacted] was paid for non-firm products.[56] Consequently, the Company's modeling methods which are geared toward STF transmission are inappropriate – the modeling method should be tailored to non-firm transmission purchases rather than STF purchases. This has changed from prior cases, where STF, rather than non-firm was the more important product.

Q. WHAT IS THE IMPLICATION FOR NPC IN THE TEST YEAR IN THIS DOCKET?

A. The Company's modeling of the STF and non-firm purchases as purely fixed costs for a single year, coupled with a four-year average of capacity is a mismatch between cost and capacity. Further, because nearly all of the non-firm transmission purchases are hourly transactions priced on a volumetric basis, modeling non-firm purchases as fixed costs is inappropriate. Finally, the Company's modeling of four years of STF and non-firm transactions is overly complex. The Company includes 67 different links for the combined non-firm and STF transmission. These links are based on an analysis of more than 14 thousand transactions with more than 30 counterparties. Despite including all these links the Company's modeling captures only about 39% of the historical volumes in GRID, while capturing 100% of the cost in the most recent year.

Q. DOES THE COMPANY'S MODELING NEED TO BE THIS COMPLICATED?

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[55] This excludes Cal ISO purchases which the Company does not model as part of the STF transactions.

[56] See Attach R746-700-23.C8-1\UTGRC12w_Wheeling (Confidential).xlsx

A. No. In the historical period just eight counterparties were responsible for 96 percent of all non-firm purchases. Rather than modeling many transactions that occurred years ago, it would make far more sense to model the transactions with these few counterparties based on the same historical data as used to determine the test year costs. For almost all other transmission purchases the Company models the links based on current ratings and the costs based on the 12 months of historical data. There is no reason STF and non-firm transmission should not be done in the same way.

Q. HAVE YOU PERFORMED SUCH AN ANALYSIS?

A. Yes. I obtained trade tickets for all non-firm transmission purchases with the eight most important counterparties and analyzed the data.[57] Confidential Table 5 below summarizes the results. The Table 5 figures show that more than 90% of the non-firm transmission purchases are hourly products, with a price specified on a volumetric basis.[58] This means that rather than modeling the cost of non-firm transmission on a fixed cost basis, it should be modeled on a volumetric cost basis.[59]

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[57] OCS DR 16.1-2, Attachment WIEC 21.29.

[58] PPW Transmission is included as a counterparty in the table as well. This represents transactions that PacifiCorp Energy makes with PacifiCorp transmission, and amounts to a reallocation of transmission rights when other parties do not need it. It is included in the test year at zero cost by the Company, as ratepayers are already paying for this resource in the test year allocations between jurisdictions.

[59] Volumetric pricing was used in prior cases in Utah, but was abandoned by the Company in favor of its new method which combined STF and non-firm transmission.

[redacted]

Q. ARE THERE OTHER PROBLEMS WITH THE COMPANY'S MODELING OF NON-FIRM TRANSMISSION?

A. Yes. The Company's method is unsound because it cannot readily demonstrate any linkage between the non-firm transmission capacity costs it is including in the test year with any of the capacity links it is modeling.[60] For example, the Company made substantial non-firm transmission purchases from Idaho Power to wheel over Path C. With the completion of the recent transmission upgrades such purchases are no longer needed. Absent a pro-forma adjustment, the related purchase costs would be included in GRID. While the Company did make a pro-forma adjustment in this instance, it is very difficult to determine whether there are other circumstances where the Company has included costs in the test year that are related to STF or non-firm transmission links that are no longer useful, either because the system has changed, or because market conditions have changed rendering the links unnecessary.

[60] Docket No. 10-035-124, OCS DR 8.40.

Conversely, the Company's modeling may include links that are being used, but without any cost being included in the test year. By modeling the links and prices on a consistent basis, it is much more feasible to produce a balanced test year.

Q. HOW HAVE YOU ADDRESSED THIS ISSUE?

A. I developed a modeling of all transactions with the counterparties listed in Table 5 above. This is only a subset of the entire universe of STF and non-firm transactions the Company entered into in the historical period. However, it represents the most important transactions. I ended up with less than half as many links as the Company used. The variable costs of these links, based on the actual trade tickets, were used in my GRID run. I excluded all of the STF/non-firm links modeled by the Company from the test year. Finally, even though I did not model any links associated with STF transmission or other non-firm transaction, I did include all of the test year costs counted by the Company. For purposes of this case, I am satisfied that this approach is reasonable, although in future cases it may be necessary to model STF transactions if the STF volume increases. Finally, even though I did not model any links associated with STF transmission or other non-firm transaction, I did include all of the test year costs counted by the Company.

Q. WHAT IS THE IMPACT OF YOUR MODELING METHOD?

A. GRID always understates non-firm transmission volumes. In the test year the Company only models [redacted] million MWH of STF and non-firm transmission, as compared to more than [redacted] million MWH from the major counterparties during the historical period. When these low volumes (39% of the total) are coupled with 100% of historical fixed costs the Company includes in the test year, the Company clearly overstates the unit cost of STF and non-firm transmission. In the modeling I propose, more than 70% of the historical volumes are included in the historical period, and the pricing is exactly what the Company paid during the same period based on the trade tickets. Further, I included all of the costs for the counterparties not modeled in the links. The proposed adjustment shown in Table 1 incorporates these modeling changes.

H. Forced Outage Modeling

Q. PLEASE EXPLAIN THE DIFFERENCE BETWEEN PLANNED OUTAGES AND FORCED OUTAGES.

A. Planned outages are due to necessary maintenance, and can be scheduled in advance. Forced outages are unexpected failures, which happen at unpredictable times. For example, if I take my car in for an oil change it's a planned outage. If it suddenly stops running, that's a forced outage. GRID models planned outages by scheduling outages at specific times. Forced outages are modeled using thermal deration factors.

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

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

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

A. Yes. Any increase in planned or unplanned outages increases NPC. Consequently, it is important to review all outage events to determine if they were prudent or reasonable for inclusions in the four-year average.

Adjustment 21: Extended Planned Outages

Q. HAVE THERE BEEN ANY SITUATIONS WHERE CONTRACTOR ISSUES RESULTED IN EXTENDED PLANNED OUTAGES?

A. Yes. During the four-year period there were many different events where planned outages took longer than necessary because of the failure of contractors to meet their contractual obligations. Exhibit OCS 4.4D provides copies of discovery responses detailing these issues. These events resulted in liquidated damages payments from the contractors to the Company in compensation for the extended outages. The fact that compensation was made is evidence of the failure of the contractors to perform according to the contractual terms.

Q. WHAT IS YOUR RECOMMENDATION?

A. Events resulting in liquidated damages payments should not be assumed to occur routinely in normalized operations. Consequently, I recommend these events be removed from the test year. The proposed adjustment eliminates the impact of these events on NPC.

Adjustments 22 and 23: Lake Side and Colstrip 4 Outage Rate

Q. PLEASE EXPLAIN THIS ADJUSTMENT.

A. In reviewing the Company workpapers, I noticed that Lake Side had [redacted] outage rate modeled in GRID. In examining the data supporting this figure, I found that more than [redacted] of the lost energy occurred [redacted]

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

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

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

A. No. These were extremely rare events and quite unlikely to recur once every four years, as is assumed in the Company's four-year moving average calculation. It is very unlikely that these events are representative of conditions in the rate effective period. As a result, including these events in the test year outage rate will produce an inaccurate forecast.

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend the periods when these outages occurred be removed from the four year period and instead I compute the outage rates based on the data for remaining months. This is equivalent to assuming that the energy lost during these long outages was the same as the average amount of energy lost for the rest of the period. This provides a much better approach to forecasting future outage rates for the rate effective period. It is quite unrealistic to assume such long outages will re-occur once every four years, as is the premise underlying the Company method.

Q. HAS THIS ISSUE BEEN CONSIDERED BY REGULATORS ELSEWHERE?

A. Yes. In Oregon after the 2007 power cost update case, UE 191, this issue of long outages was addressed. The OPUC decided to limit outages to no more than 28 days.[61] More recently, in Oregon Docket UM 1355 (a generic investigation into methods to improve outage rate forecasts), the OPUC implemented a new outage rate forecasting method that

[61] The Oregon order states: "The Company documents show that the anticipated duration of the resulting outage was five to seven weeks. An outage of that duration, no matter what the cause, is anomalous, and raises issues regarding its inclusion in normalized rates. In this case, we find that a 28-day period is a reasonable limit on the length of the outage for the purpose of calculating the TAM adjustment factor. To the extent the actual outage exceeded 28 days, the Company should make an appropriate adjustment to the outage rate used in running the GRID model." OPUC Docket No. UE 191, Order 07-446 at 21 (Oct. 17, 2007).

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replaces very long outages with more representative figures.[62] In the current Oregon proceeding, the Company has made several adjustments to outages in its test year, including one for the Colstrip 4 event.[63] In WUTC Docket No. UE-100749, regulators decided to adopt an adjustment replacing the long Colstrip outage with a more typical outage rate during that period. The WUTC made the adjustment on the basis it would improve forecast accuracy.[64]

Q. DOES THE IMPLEMENTATION OF THE EBA HAVE A BEARING ON THIS ISSUE?

A. Yes. Traditionally, the four-year average provided the sole means of recovery for the costs associated with long outages. Now, the EBA is in place, and recovery of long outage costs through that mechanism is allowed. Consequently, there is no need to attempt to reflect long outage costs in the NPC baseline. Rather, the removal of long outages will improve the baseline forecast accuracy.

<u>Adjustment 24: Naughton 3 Outage</u>

Q. PLEASE EXPLAIN THE BASIS FOR THIS ADJUSTMENT.

A. This adjustment removes outage events that occurred at [redacted] According to the Company, [redacted]

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[62] OPUC Docket UM-1355, Order 10-414, page 5.

[63] See OCS DR 2.88 Confidential.

[64] WUTC Docket No. UE-100749, Order No. 6, paragraph 140, page 53. Note that the Lake Side outage was not at issue in Washington because Lake Side is not recognized in rates on other grounds.

[redacted]

Because the Company was [redacted], imprudence and/or negligence has already been established. The primary impact of this event was to increase the test year outage rate for Naughton 3, thus I recommend it be removed from the test year since it would not be reflective of ongoing expected outages. Rates should not be premised on the assumption contractors consistently fail to meet contractual obligations.

<u>Adjustment 25: Minimum Loading Deration and Heat Rate Modeling</u>

Q. WHAT IS THE PURPOSE OF THIS ADJUSTMENT?

A. GRID systematically overstates thermal plant heat rates, thus increasing fuel costs as compared to results that would occur at the normal operating efficiency of thermal plants. This occurs for a number of reasons. A significant reason is that in GRID thermal units are simulated as running below their optimal dispatch levels.

This adjustment corrects heat rates so they are not artificially inflated due to the deration of unit maximum capacities used to model forced outages in GRID. A modeling technique designed to eliminate this problem is already used by at least one other regional utility, Portland General Electric ("PGE"), in its power cost model, MONET. I believe this represents standard industry practice. Further, this technique was recommended for application to PacifiCorp by OPUC Staff witness, Ms. Kelcey Brown, in OPUC Docket UM 1355.[65] The adjustment I propose in this case is intended to provide a simplified solution to this issue.

Q. HAS THIS ISSUE BEEN ADDRESSED IN PRIOR CASES?

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

A. Yes, although the Commission has never made a final decision regarding the merits of this matter. The issue was fully litigated in Docket 09-035-23 and the Commission continued to accept the Company methodology. However, the Commission's Final Order asked for more analysis and stated on page 57 as follows:

> We direct the Company, Division and other interested parties to review alternatives for addressing this issue, review actual operations in comparison to modeling predictions, and to understand the extent of the issue.

The Company has not addressed this issue in this case, and in the prior case (Docket No. 10-035-124, which was settled), Mr. Duvall stated he did not prepare any analysis to address the Commission's order because he did not agree with the adjustment.[66] During the interim period, the parties did attempt to explore various alternatives, but the Company withdrew from the process unilaterally.

Q. HAVE YOU PERFORMED ANY NEW ANALYSIS TO ADDRESS THE COMMISSION'S REQUIREMENT FROM DOCKET 10-035-124?

A. Yes. I have compared actual operating heat rates to GRID model heat rates and will demonstrate that without the proposed adjustment, GRID substantially overstates NPC because it produces heat rates higher than actual operations.

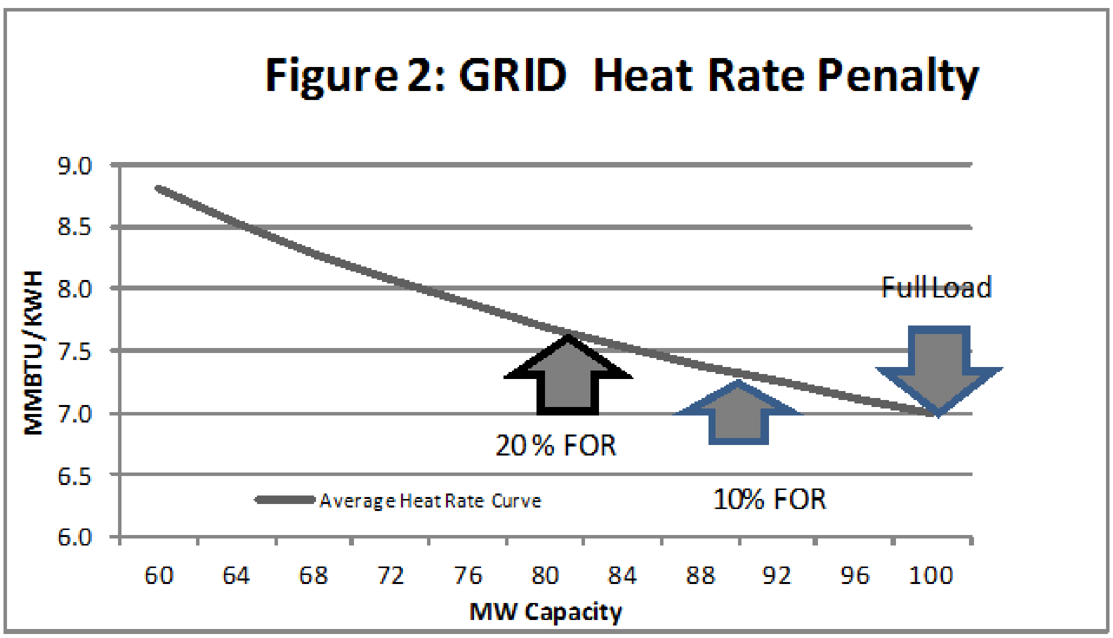
Q. EXPLAIN THE BASIS FOR THIS ADJUSTMENT.

A. As noted above, in GRID, forced outages are modeled by "shrinking" the capacity to account for outages. For example, a 100 MW unit with a 20% forced outage rate is seen as an 80 MW unit.

A problem with this aspect of the GRID modeling is that when the capacity of units is derated to model outages, there is a mismatch with the heat rate curve. The

[66] Duvall Direct Testimony Docket No. 10-035-124, page 31.

Company would apply a heat rate curve sized for a 100 MW unit to the now “shrunken” 80 MW unit. Much like driving a car sixty miles per hour in 3rd gear, this is inefficient. The chart below shows what happens when a heat rate curve sized for a 100 MW unit is applied to the artificially shrunken 80 MW unit. The unit artificially “moves up the heat rate curves” and efficiency appears to be reduced. As the forced outage rate (“FOR”) increases for a unit, its heat rate normally increases in the GRID modeling. This, however, is highly unrealistic, as lengthening the period of a forced outage should have no effect on the unit’s average heat rate. The GRID method “rewards” the Company for having high outage rates by artificially inflating the heat rate. This is a “win-win” for the Company and a “lose-lose” for customers.



Q. CAN YOU DEMONSTRATE THIS PROBLEM IN THE COMPANY’S GRID RUN?

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A. Yes. When the long outage for Colstrip 4, which I discuss above, was removed from the GRID database the average heat rate for the plant decreased from [redacted] to [redacted] BTU/KWH. In other words, because the long Colstrip outage increased the forced outage rate the GRID model assumes a reduction in the efficiency of the unit. However, it stands to reason that the time spent when a plant is sitting idle should have no impact on its average heat rate. In GRID, Colstrip 4 runs at full loading virtually every hour of the year. There is no reason why its heat rate should increase just because the plant has a higher forced outrage rate.

Q. WHAT IS THE SPECIFIC CAUSE OF THIS PROBLEM?

A. It is a "model induced error." Rather than modeling a full outage of one day in five (20%) in GRID, the Company assumes that the generator runs only at 80% of its full capacity every day. In reality, the plant may be running at full load for four days and not at all the fifth. When running at full load it will be more efficient than is assumed to be the case when running at 80% of its maximum.

Q. CAN YOU ILLUSTRATE THIS PROBLEM FURTHER USING COLSTRIP AS THE EXAMPLE?

A. Yes. Confidential Table 6 below illustrates the problem. It shows the heat rate equation used in GRID for Colstrip Unit 4. Based on the data used in GRID, the capacity of Unit 4 is [redacted] MW (for the PacifiCorp 10% share of the unit). However, there are partial outage derations that occur that lower the available capacity to [redacted] MW 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] MW 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] per hour for the Company’s 10% share. While this may seem like an inconsequential amount of money this problem occurs thousands of hours per year for nearly every unit. In total it is a substantial amount. For Colstrip 4 alone, based on [redacted] hours of operation in the test year, this would amount to [redacted] thousand.

[redacted]

Q. ARE THERE OTHER ASPECTS OF THIS PROBLEM?

A. Yes, the analysis shown in the Table above only isolates the problem at the top of the heat rate curve. A similar problem exists at lower loadings. Further, the Company reduces the maximum capacity of units in GRID to model outages, but does not do so for the minimum loading levels. It is possible to implement a more comprehensive adjustment in GRID to address these issues.

Q. PREVIOUSLY MR. DUVALL HAS ARGUED THAT THIS ADJUSTMENT IS INCORRECT BECAUSE IT DERATES THE MINIMUM LOADING OF A GENERATOR TO A LEVEL BELOW ITS ACTUAL OPERATING MINIMUM.

A. His concern about the deration of the minimum capacity is misplaced. The Company models the maximum capacity of generators to less than the actual maximum to reflect outages. There is no reason they should not do the same for the minimum capacity. In any case, this is a simple matter of computing an expected value – the probability weighted average.

Assume a 100 MW unit, with a 20% outage rate and a minimum capacity of 25 MW. If the unit were to run only at minimum capacity (which is frequently how gas units are modeled in GRID), under the Company method it would generate 25 MW 100% of the time without any deration of the minimum capacity. However, the unit is on outage 20% of the time, so in actual operations it would generate 25 MW only 80% of the time and zero MW the rest of the time. Ignoring the deration of minimum capacity can lead to overstatement of generation. Further, it can, and actually has led to very perverse situations where the minimum capacity of a unit is actually greater than the maximum capacity modeled in GRID, producing very distorted results.

This is the method used in the PGE Monet model discussed above. I am also involved in a current Public Service Colorado IRP case, where that Company is modeling coal cycling costs. The PSCo model also derates minimum capacity levels. I believe this amounts to standard industry practice.

Q. CAN YOU DEMONSTRATE WHICH APPROACH MOST ACCURATELY PREDICTS ACTUAL HEAT RATES AND FUEL COSTS?

A. Yes. Confidential Table 7 below summarizes a comparison of 2007-2011 actual heat rates to the GRID simulations using the Company method and a GRID simulation using my proposed OCS adjustment. Table 7 shows that my adjustment improves the accuracy, as compared to actual data. The line called “Closest to Actual” counts the number of instances where each method produced the results that were the closest to the actual heat rates for the units. For 23 of 36 units, producing closer agreement to the actual data for all units on average, and for coal and combined cycle plants when viewed as groups. The Company method produces slightly more accurate results for the Gadsby Units 1-3, but both methods are fairly inaccurate for these units which seldom run. Ignoring these three units, the proposed methodology is preferable for 23 of 33 units (70%). The table also shows that the GRID method overstates fuel costs by using heat rates that are systematically higher than actual data. This bias amounts to $11.4 million in additional NPC in the test year as shown in Table 7 below. The proposed adjustment reduces, but does not eliminate most of this bias.

[redacted]

Q. THIS ISSUE HAS BEEN LITIGATED IN OTHER STATES. WHAT HAVE REGULATORS ELSEWHERE DECIDED?

A. In its order in Oregon Docket UM 1355, the OPUC adopted my proposed methodology, incorporating both the heat rate adjustment and minimum loading deration discussed above.[67] Further, Washington regulators have also adopted this adjustment in a recent decision.[68]

Q. THE MINIMUM LOADING DERATION AND HEAT RATE ADJUSTMENT IS QUITE COMPLEX. DO YOU HAVE AN ALTERNATIVE PROPOSAL?

[67] OPUC Docket No. UM 1355, Order 10-414, page 7.
[68] WUTC Docket No. UE-100749, Order No. 6, paragraph 191, page 68.

A. Yes. The Commission could simply make an adjustment to remove the heat rate bias from GRID, based on the figures shown in Table 7. This would eliminate the need for the minimum loading deration and heat rate adjustment. If adopted, it would also be appropriate to include the corrected value of the Lewis River efficiency loss adjustment discussed above, though the amount of the adjustment should be corrected as I indicated earlier.

<u>Adjustment 26: Final Balancing (Overlap) Adjustment</u>

Q. WHAT IS THE PURPOSE OF THE FINAL BALANCING ADJUSTMENT?

A. As discussed above in relation to the screening adjustment, this adjustment, shown on Table 1 provides a placeholder for the final balancing impact of the Commission approved adjustments in my proposed final GRID run. NPC Adjustments can have an effect on each other. For example, if the capacity of a generator is increased, it would magnify the effect of an adjustment related to outages for that unit because both change the units' output. Likewise, an adjustment that changes transmission capacity would change the impact of an adjustment that reduces market prices because it would change sales levels. Because we do not now know what NPC adjustments proposed by OCS or other parties will be approved by the Commission, it is not possible to provide a final figure for the Final Balancing/Overlap Adjustment. However, there are some overlaps between a few of the OCS adjustments and/or the Company's proposed update. The overlaps included were removal of adjustments included in the Company update (the SMUD correction and the revenue adjustment included for the Centralia contract). Table 1 also shows both the correction to the Lewis River loss of efficiency adjustment (Adjustment 13) and the complete removal of the adjustment (Adjustment 14). The overlap adjustment removes the Lewis River correction from the Total NPC because

OCS' primary recommendation is to remove the Lewis River efficiency loss adjustment made by the Company completely. The correction is only an alternative in case the Commission does not agree to remove the Lewis River loss of efficiency adjustment entirely. Also, the Non-Owned Wind Integration Cost adjustment is reduced if OCS' reserve calculation is adopted, as discussed above. All of these overlaps are removed on the Final Balancing/Overlap adjustment shown on Table 1.

III. NPC UPDATE ISSUES

Q. HAS THE COMPANY PROPOSED TO MAKE UPDATES TO NPC DURING THIS PROCEEDING?

A. Yes. The Commission's scheduling order states that the Company plans to file an update of NPC approximately one month before the filing of intervenor testimony. It is my reading of the order that the Commission is not necessarily indicating it will approve such an update in general or any particular update. The order further states that parties will have the opportunity to address the proposed updates in either their direct testimony or at the time of the rebuttal filing.

Q. ARE THERE PRACTICAL ISSUES THAT MUST BE CONSIDERED IN PROCESSING UPDATES DURING A CASE?

A. Yes. Updates pose certain practical problems for parties attempting to address the Company's filings. Utah has a very short statutory period for processing a general rate case (240 days) and the discovery turn around period is very lengthy: 21 days. Other states often have longer case schedules and shorter discovery turn around periods. This makes processing changing information during a case more difficult.

Updates change the NPC baseline, GRID inputs, etc. Dealing with multiple NPC studies makes it more difficult to determine the impact of adjustments for both opposing parties and the Commission. By itself, this is not an overwhelming problem, so long as the number and scope of updates is limited and the timing of updates is reasonable. However, the problem is not limited only to what updates the Company makes but any countervailing updates that are not made. Updates should not be done in an asymmetrical manner. Because the Company is the controller of the information limiting the number and scope of updates may help alleviate potential problems. Referring back to the transmission loss adjustment, in this case, the Company chose not to include the most recent data available at the time of its filing, nor did it propose to include the transmission loss update as part of its update filing. This raises concern about the equitability of the Company's approach to updates.

Q. WHAT IS YOUR RECOMMENDATION CONCERNING THESE MATTERS?

A. One update, approximately halfway between the Company initial filing date and the intervenor testimony filing date could be effectively reviewed by opposing parties. Such updates should be limited to changes in third-party contracts for fuel, power and transmission services. Correction of filing errors should also be allowed. Index-related changes for third party coal contracts should not be allowed because changing an index would be much like changing the rate of inflation, cost of capital, or any other macroeconomic variable. This would quickly degenerate into the equivalent of a new rate filing.

The Company should not change the time frames, methodologies or assumptions relied upon in developing NPC inputs. For example, various contract inputs, outage rates and heat rates are normally based on four years of historical data. Updating the four-year period would mean that parties would have to now investigate substantial amounts of new information concerning these inputs. This would greatly complicate these proceedings.

Q. ARE THERE OTHER TYPES OF UPDATES THAT SHOULD NOT BE ALLOWED?

A. Macro economic assumptions such as escalation rates or inflation rates assumed in input development (to the extent not specified by contract) should not be updated. It is my understanding that this is not done with respect to base rate items, consequently, it shouldn't be done for power costs. Further, owing to the EBA mechanism there is less need for updates of this type. Finally, such global assumptions are generally provided by third party vendors and it is difficult for parties to perform a meaningful review of such assumptions in a short period of time.

The methods used to compute inputs should be frozen with the filing as well. While correcting errors would be appropriate, it would not be reasonable to allow the Company to change its underlying methodologies under the guise of an update.

In some cases, the Company purchases gas or electric transmission service from regulated suppliers. In those cases, the supplier may have rate change requests pending at the FERC. In such instances, updates would be reasonable if a decision is rendered by the FERC by the time of the initial update, and if the Company can realistically determine the impact on its revenue requirements. However, speculative updates related to pending cases should not be allowed.

Unless such limitations are imposed, the update filings will take on the dimensions of a new rate case filing, with less time available for a full review. One can easily imagine how difficult and complex such a process would be. Updates should be limited to the most important factors and to those factors which are most readily verifiable.

Q. PLEASE DISCUSS THE MATTER OF FORWARD PRICE CURVE UPDATES.

A. The forward price curve is a very important factor, though not one easily verified by opposing parties absent some change to the Company's practices. In prior litigated cases the Commission has not approved the Company's proposed forward price curve updates.

Q. EXPLAIN THE DIFFICULTIES PARTIES HAVE IN VERIFICATION OF THE COMPANY'S FORWARD PRICE CURVES.

A. The Company designates the workpapers underlying its forward price curves as "Highly Confidential." This means the only way in which a party can review the documents is to go to a secure location and examine it visually. Parties are not allowed to obtain the

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actual spreadsheets used by the Company in developing the forward prices. This all but eliminates any ability to correct or modify the forward prices used by the Company. Further, having to obtain the update documents via the ordinary discovery route would likely make validation of a new OFPC in the final update impossible. Under the current Commission rules, the Company is not required to file any documents related to the development of its OFPC. This means that the normal discovery process must be followed.

Q. DID OCS VALIDATE THE COMPANY'S OFPC IN THIS CASE?

A. Yes. One of the OCS consultants, Mr. Philip Hayet, did validate the Company OFPC in this case following the Company's procedures. While OCS has no objections to the Company's filed OFPC in this case, it is not clear how one would deal with this issue in the event an issue or problem was uncovered, particularly in a final update.

Q. WHAT IS YOUR RECOMMENDATION REGARDING OFPC UPDATES?

A. If allowed by the Commission, any OFPC update should be accompanied by complete supporting documentation provided under the ordinary confidentiality provision of Rule 746-100-16, rather than the "Highly Confidential" protections the Company has imposed. It is my understanding that the Commission has not approved such extraordinary treatment of these confidential documents and this practice should not be allowed to continue.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.