Witness OCS 4SR

BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Application of	**)**	**Docket No. 10-035-124**
Rocky Mountain Power for Authority to	**)**	
Increase Its Retail Electric Service Rate in	**)**	**Surrebuttal 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 – Public Version

July 19, 2011

SURREBUTTAL TESTIMONY OF RANDALL J. FALKENBERG

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Randall J. Falkenberg, PMB 362, 8343 Roswell Road, Atlanta, Georgia 30350. I am the same witness who filed direct and rebuttal testimony in this proceeding.

Q. WHAT IS THE PURPOSE OF THIS TESTIMONY?

A. I reply to Mr. Duvall's rebuttal testimony regarding NPC issues and discuss his new NPC adjustments. I also modify the OCS NPC recommendations. In OCS 4.1SR I present the OCS position on the remaining contested NPC adjustments.

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSAL TO REVISE NPC BASED ON THE ITEMS LISTED IN EXHIBIT GND-2R?

A. Exhibit GND-2R lists 29 adjustments (counting balancing). Adjustments 1-8 are "Error Corrections." Adjustments 9-18 are classified as "Updates", while Adjustments (19-26) are characterized as "New Information." Adjustments 27 and 28 are adjustments proposed by DPU, OCS or UIEC adopted by the Company, while Adjustment 29 is a balancing adjustment. Some of these 29 adjustments reflect adjustments already proposed by opposing parties, while others are new. I recommend the Commission allow the "Error Corrections" but not allow the adjustments characterized as "Updates" and "New Information" unless they have previously been proposed by OCS, DPU or UIEC.

Q. PLEASE EXPLAIN YOUR REASONING CONCERNING WHICH ITEMS SHOULD BE ALLOWED AND WHICH SHOULD NOT.

A. I don't oppose error corrections, and most of the important ones listed in GND-2R have already been vetted by one of the witnesses for the OCS, DPU or UIEC. I also agree with the inclusion of the OCS, UIEC and DPU adjustments adopted by the Company.

As regards the Updates and New Information categories listed on GND-2R, the Company has been very flexible in its characterization of these adjustments. In fact, some of the items amount to error corrections known via discovery before the intervenor direct testimony due date. Examples include the fuel cost errors and the hydro outage rate base period. These are embedded in some of the Company proposed adjustments. These problems were already detected in the intervenor testimony.

Another example concerns the matter of the Start Up O&M (Adjustment 15 on GND-2R) proposed by the Company. This is not an update because the contracts that the Company relies upon for this adjustment were in effect long before the test year began and the update is not based on recent changes in computation of an index or the like. Rather, Adjustment 15 simply amounts to the Company changing its interpretation of the data and its modeling methods, much like the expansion to Market Caps or the proposed changes to Non-Firm transmission modeling. Changes in methodologies used by the Company should be brought up in its direct case, not under the guise of an update. This adjustment is all the more troubling because although Mr. Duvall now wishes to rely on these contract documents for purposes of determining GRID inputs, he has recently opposed using the same GRID start up costs data to model generation overhaul expense.[1]

Another example of the problems with the Company's approach to updating is that opposing parties do not have access to all of the same information as the Company and the Company has been selective about what items it updates. For example, while

[1] Duvall Rebuttal Testimony, Wyoming PSC Docket No. 20000-384-ER-10, page 64. Mr. Duvall contended it was not proper to account for the reduction in overhaul expense stemming from the reduction in the number of starts for combined cycle plants. Consequently, Mr. Duvall uses start up cost data in GRID where it increases NPC and reduces the number of start ups, but refused to consider the O&M savings resulting from the reduction in the number of starts.

OCS no longer is recommending the line loss adjustment (OCS 13.1) the Company did not update its filing to incorporate the most recent five years of losses, which would have lowered NPC. Consequently, it is not possible to determine whether the Company has made the updates in an even handed manner.

With respect to what constitutes new information, I believe that the most important items were already identified in discovery by the parties, and there is not sufficient time at this stage of the proceeding for opposing parties to fairly evaluate all of the 18 additional adjustments now being proposed by the Company. In prior cases, the Commission has not given blanket approval to Company proposed updates in the rebuttal stage of the case, and I recommend it not do so in this case, either.

Q. HAS THE COMMISSION ALLOWED THE FORWARD PRICE CURVE UPDATE (ADJUSTMENT 9 ON GND-2R) IN PRIOR CASES?

A. The Commission has turned down the Company's request in the last two general rate cases where power cost issues went to hearing. OCS recommends the Commission continue with this practice and reject Adjustment 9 on GND-2R. However, most of the adjustment ($7,518,624 on a total Company basis) is due to new STF contracts. In prior cases, the Commission has allowed some contract updates and the STF contracts are not as difficult to verify as the forward price curve update. If the Commission does allow the Company to update forward prices, it is all the more important they require a final GRID run incorporating all adjustments.

<u>Issues No Longer In Dispute</u>

Q. ARE THERE ANY ADJUSTMENTS WHICH ARE NO LONGER IN DISPUTE?

A. Yes. Mr. Duvall has accepted, or incorporated several OCS Adjustments: Roseburg correction (OCS 6.2), Bear River Capacity and Energy (OCS 7.1), BPA Network Forecast (OCS 12.2), Fuel Price Corrections (OCS 19.1) and Capacity Upgrade (OCS 20.1). OCS also withdraws the following adjustments: BPA/IPC Rate Increase (OCS 12.1), Line Loss (OCS 13.1), New Mexico LF Contract (OCS 14.1)[2] and Cholla Reserve Capacity (OCS 17.1).

OCS conditions withdrawal of these adjustments. In the case of OCS 12.1, OCS agrees the Company proposal to defer the additional revenues from its pending FERC wheeling rate increase until the next GRC is a reasonable resolution of the issue. However, any transmission related charges now subject to refund (such as the Idaho Power Transmission rate increase)[3] should also be deferred until the next case. In the case of the Cholla reserve capability, I will demonstrate that Mr. Duvall's analysis of actual reserve requirements for 2010 relies on substantially greater capacity for the Cholla plant than the transmission constraints he says limit the plant's output to 387 MW. If the Commission were to accept that analysis, then it should also accept OCS 17.1. However, the Company's new analysis of actual reserves is flawed so I recommend the Commission reject it.

<u>Partially Resolved Issues</u>

Q. ARE THERE ANY PARTIALLY RESOLVED ISSUES.

A. Yes. The Company accepts part of the Hydro Outage Rate Adjustments (OCS 9.1) and I have reduced some of the remaining adjustment that is in dispute. The Company has also accepted part of the Station Service Correction.

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[2] This issue may warrant examination in future cases, though I am satisfied for now regarding the Company's explanation.

[3] OCS 33.9

Contested Issues Not Addressed

Q. WILL YOU ADRESS ALL OF THE CONTESTED ISSUES IN THIS TESTIMONY?

A. No. There are many issues which are either relatively unimportant, already have a fully developed record, or for which the Company rebuttal amounts to little more than a recitation of its direct testimony. In such cases, I don't address the issues here, although I continue to support the adjustments. This includes OCS 3.1 (Start Up Fuel Outage Adjustment), OCS 3.2 (Start Up Energy Value), OCS 4.1 (UMPA II Shaping), OCS 4.2 (Black Hills Shaping) and OCS 12.3 (Imbalance Normalization). In these cases, I believe the record is complete. Likewise, I will present only limited discussion of the outage rate adjustments (OCS 21.1-21.6) because the record is well developed.

Adjustments 1 & 2: Wind Integration Costs

Q. DOES THE COMPANY AGREE WITH THE WIND INTEGRATION ADJUSTMENTS PROPOSED BY OCS?

A. No. While Mr. Duvall does not actively dispute the technical substance of my critique of the Company's 2010 Wind Integration Study ("Wind Study") he continues to claim the Company study is "accurate."[4] This is despite the fact that the Company acknowledged in discovery responses the existence of approximately 80 errors in its wind integration study. To date, the Company has not made a single correction to its study, nor does Mr. Duvall even acknowledge any of the errors in his testimony. It is a bit puzzling that the Company has made corrections to the GRID model in Exhibit GND-2R, as small as $1,739 Total Company yet did not correct a single error in the Wind Study data it input into GRID. It is also telling that now that the Company is requesting to collect wind

4 Duvall Rebuttal, page 32.

integration costs from its FERC customers in its pending Transmission Rate Case ("TRC"), it is not using the 2010 Wind Integration Study to support that request.[5]

Mr. Duvall makes three primary arguments to defend his wind integration assumptions: 1.) The Wind Study and GRID results are reasonable based on a comparison of the BPA Wind Integration charge of $1.29/kW-month; 2.) The collaborative process fairly considered and reflected stakeholder inputs, and; 3.) Actual data for 2010 validate the Wind Study results. Mr. Duvall is wrong on each point. His new analysis of actual wind integration reserve requirements contains numerous mistakes and inconsistencies which, once corrected validate the OCS reserve requirement modeling. Indeed, his new study is just as flawed as the Company's 2010 Wind Study. Neither analysis is useful for ratemaking purposes.

<u>Comparison to the BPA Wind Integration Tariff</u>

Q. PLEASE DISCUSS MR. DUVALL'S COMPARISON OF THE PACIFICORP WIND STUDY RESULTS WITH THE BPA WIND INTEGRATION TARIFF.

A. Mr. Duvall testifies that the PacifiCorp wind integration cost included in the test year is $6.54/MWH.[6] He believes this compares favorably to BPA's charge of $1.29/kW-Month which he equates to $5.34/MWH.[7] However, his comparison is simply invalid because 85% of the charges in the BPA tariff are designed to recovers <u>embedded</u> (fixed) costs while the GRID model recovers only <u>variable</u> costs. The PacifiCorp Wind Study is intended only to identify the variable costs of wind integration because the fixed costs of

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[5] OCS 33.4. Note that the Company objected to answering this question.

[6] Duvall Rebuttal, page 26, line 570. This is the figure Mr. Duvall used in his recent Wyoming testimony. On the same page Mr. Duvall also references a figure of $6.49/MWH for the PacifiCorp wind integration cost. It is not clear which he believes is correct.

[7] Duvall Rebuttal, pages 26-27.

wind integration are already being recovered in base rates as part of the return on rate base, depreciation and fixed O&M.

Mr. Duvall is comparing the "all in" cost of BPA's service to the variable cost of PacifiCorp's of wind integration. It would be the same as comparing the "all in" cost of a BPA combined cycle plant, with the fuel cost of a PacifiCorp combined cycle plant. The comparison is simply misleading, and adds nothing of value to the discussion.

Q. WAS MR. DUVALL AWARE OF THIS DISTINCTION?

A. Apparently not. In a discovery request I asked if the Company was aware that BPA's rate contained embedded cost. The Company's response was that "*The Company is not in a position to characterize the wind integration charge developed by BPA.*"[8] Considering the reliance the Company places on comparison to the BPA charge this seems rather questionable.

Q. CAN YOU CHARACTERIZE THE WIND INTEGRATION CHARGE DEVELOPED BY BPA?

A. Yes. Exhibit OCS 4.2SR is a copy of BPA's public record workpapers used to develop the $1.29/kW-Month wind integration charge. BPA projected this rate would recover the $47.4 million wind integration revenue requirement. Of this amount, $40.2 million or nearly 85% are embedded, or fixed costs. Only the remaining 15% of the charge ($.82/MWH) is comparable to PacifiCorp's proposed charge of $6.62/MWH. PacifiCorp's proposed variable cost charge is obviously many times the comparable BPA charge.

Q. HAS MR. DUVALL OVERLOOKED ANY OTHER ISSUES CONCERNING THE BPA CHARGE?

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[8] Wyoming Public Service Commission Docket No. 20000-384-ER-10, WIEC 8.20

A. Yes. Mr. Duvall also ignored the fact that the BPA charge is not applied to wind projects smaller than 20 MW. This condition could exclude as much as 99 MW, or about 6% of the wind projects included in the test year. This amount should also have been factored into Mr. Duvall's comparison. I think the real lesson from this is that making comparisons to other studies and charges of other utilities results in more confusion than clarity.

Q. HAS THE COMPANY PERFORMED ANY COMPARISON OF ITS PROPOSED WIND INTEGRATION CHARGES IN THE PENDING TRC TO THE BPA RATE?

A. No, and in OCS 33.3 the Company objected to even answering this request. If any comparison of this sort is meaningful, the comparison of the Company request in this case, to its request in the FERC case would probably be the most pertinent. In the FERC case, the Company is requesting a charge of only $.34/KW month for wind integration, or $1.3/MWH for 35% capacity factor wind project. This is substantially less than it is requesting in this case for wind integration. Even more significant, the Company apparently only applies the charge to 4.24% of the installed capacity of a wind project.

Q. ARE MR. DUVALL'S COMPARISONS TO THE COMPANY'S PRIOR WIND INTEGRATION ASSUMPTIONS OR THE PORTLAND GENERAL ELECTRIC STUDY RESULTS VALID?

A. No. Mr. Duvall cites the wind integration charges the Company requested in the 2009 GRC and results from a recent Portland General Electric ("PGE") study. The level of wind integration from the last case was clearly a controversial issue, and one addressed by many parties. In the final order, the Commission directed the Company to enhance its study and address various concerns raised by the parties.[9] The prior study used no actual wind generation data and was characterized by the Commission as "unproven."[10] As I have demonstrated in Exhibit OCS 4.3 the Company's new study is completely flawed. I see no basis for assuming the Commission should revert back to use of a prior, unproven study when actual data is now available. It is important to realize that wind integration is a new issue which is controversial and difficult to quantify. It is not like going to a gas station and comparing the price with the station down the street to decide if the price is fair or like comparing the price of milk or bread a year ago. It is much more like estimating a future CO_2 tax or the cost of carbon emission control equipment. The numbers from prior analyses are really of little value.

Mr. Duvall's reference to PGE is also quite misleading. PGE is not using the referenced wind integration study results for rate making purposes because its only major wind project, Biglow Canyon, is located in BPA's transmission area. PGE purchases integration services from BPA under the same rate discussed above. As noted on page 2 of Exhibit GND-3R, *PGE does not currently self integrate*. PGE's only other wind integration costs are minor hour ahead imbalance charges from BPA and day ahead costs which are limited to $.50/MWH pursuant to a 2008 stipulation.[11] PacifiCorp has already included these same kinds of costs in its study, and they are not in dispute at this time. The only portion of the PGE integration charges comparable to the amounts requested in this case is the BPA charge which includes capacity costs as discussed above. The $14.46/MWH charge Mr. Duvall referenced is a planning study, designed to evaluate the cost of integrating additional resources in the future, not the current variable cost of

[9] Report and Order, February 18, 2010 Docket No. 09-035-23, pages 49-50.
[10] Id..
[11] OPUC Docket No. UE 198, Stipulation Regarding Outstanding Power Cost issue, July 18, 2008, page 3.

integration used for ratemaking. Further, there is nothing more than a presentation provided in support of the PGE study. There is no basis for any party in this case to perform any intelligent review of the new PGE study. It is simply not a useful point of reference and it is not even used by PGE at this time for ratemaking.

Q. HAS MR. DUVALL ACCURATELY CHARACTERIZED YOUR PROPOSED WIND INTEGRATION COST AS $3.05/MWH?

A. No. Mr. Duvall testifies that the Company test year contains $33.2 million in Wind Integration costs based on subtracting the BPA and Contingency reserve costs from Table 2 in my direct testimony. However, his math is wrong. The Company acknowledged that in OCS 33.8. In fact, while he testifies that the wind integration cost in the Company test year is $6.49/MWH in one place, and $6.54 (a figure applicable to Wyoming) in another, the correct amount is $7.06/MWH according to OCS 33.8.

The correct figure for total wind integration cost in the test year, based on Table 2 is $35.6 million not $33.2.[12] Mr. Duvall then contends that if OCS proposed adjustments are made, the cost is reduced to $3.05/MWH. This is also incorrect, for two reasons. First, he contends that contingency reserves are not part of wind integration, and they were not included in the total ($35.6 million) from OCS 33.8. However, he subtracts the contingency reserve cost from the wind integration cost in deriving the $3.05/MWH. Also, adjustment OCS 1.1 reduced the reserve requirement for "load only" based on lowering the CPS2 from 97% to 95.5%. The total reserve reduction in OCS 1.1 was approximately 113 MW. Of this amount, at least 25 MW, or 22% is attributable to reducing reserves required for load. This amounts to about $2.6 million of the total

[12] In OCS 33.8, the Company conceded that the correct figure is $35.6. It appears the $33.2 million came from Wyoming case data again.

reduction to wind integration expense. If these corrections are made, the resulting wind integration cost for the test year would be $19.9 million, or $3.95/MWH. Based on my revised Wind Integration adjustments, the final amount would be $4.33/MWH. The table below provides this analysis.

Table 1SR
Test Year Wind Integration Costs
Total Company $M

	Direct	Final
Inter-Hour Costs	4.0	4.0
Regulating Margin for Wind	21.9	21.9
Must Run Gas Plants	9.7	9.7
Total Wind Integration Cost	35.6	35.6
OCS Reserve Adjustment	11.9	11.9
Load Related Portion	22%	22%
Wind Related Adjustments	9.3	9.3
OCS Must Run Adjustment	6.4	4.5
OCS Wind Integration Cost	19.9	21.8
Test Year Wind GWH	5045.0	5045.0
Total $/MWH	3.95	4.33

Q. ELABORATE ON MR. DUVALL'S SECOND MAJOR POINT DISCUSSED ABOVE REGADING THE COLLABORATIVE PROCESS.

A. Mr. Duvall's testimony is more telling for what it doesn't say than what it does. Mr. Duvall does not deny that the Company Wind Study is replete with errors. He does not claim that the double counting errors didn't occur, that the simulated data was not erroneous, or that the dozens of math errors did not exist. Instead, he has provided an incorrect and misleading analysis that he contends validates the study results.

Q. PLEASE DISCUSS MR. DUVALL'S CONTENTIONS REGARDING THE COLLABORATIVE PROCESS.

A. Mr. Duvall has testified as follows:

> While there were instances where the Company did not agree with the recommendations made by stakeholders, at no time did the Company intentionally suppress the views and criticisms of any of the stakeholders with the intentions of driving the Wind Study to a predetermined outcome.

This comment evades the real question and instead offers a superfluous comment. The issue is *not* whether the Company attempted to *suppress* any views. Suppressing views was impossible since parties simply provided the Company with written comments which the Company then posted on its web page. Rather the question is whether the stakeholders' criticisms were actually incorporated into the study design. I pointed out in my direct testimony numerous instances where parties raised valid concerns about the study design which the Company either ignored or rejected. *In fact, important issues I have raised in this case, including the must run modeling, the double counting of reserves and the problematical nature of the simulated data were all identified by parties to the collaborative process. In each case, the Company simply asserts that its study results are right, even now after it has admitted to many errors, and the impact of these problems have been fully documented.*

Q. WERE THERE OTHER PROBLEMS WITH THE COLLABORATIVE PROCESS?

A. Yes. The Company refused to provide any workpapers to the participants. In my view this severely limited the validity of the process. The numerous errors in the Company study were impossible to identify until the workpapers were provided. However, various parties did challenge many of the Company's design assumptions as noted above.

Q. COMMENT ON MR. DUVALL'S THIRD MAJOR POINT RELATED TO A NEW ANALYSIS OF 2010 ACTUAL REGULATING RESERVE REQUIREMENTS.

A. Mr. Duvall attempts to validate the Wind Study results by producing actual reserve requirements results for 2010. It is worth noting that I had previously requested such data, but the Company stated it could not provide it.[13] Actual 2010 results would be meaningful because the amount of wind resources in the test year is approximately the same as in 2010.

Mr. Duvall claims his new analysis supports a regulating reserve (ten minute) requirement for 2010 of 344 MW and a load following (sixty minute) reserve requirement of 284 MW. Mr. Duvall adds these figures together in support of a reserve requirement of 629 MW.[14] This amount exceeds the 533 MW modeled in GRID.[15] It appears Mr. Duvall believes this validates the results of the Company wind study.

Q. DID MR. DUVALL PRESENT THE SAME FIGURES PREVIOUSLY IN HIS TESTIMONY IN THE CONCURRENT WYOMING GRC EARLIER THIS YEAR?

A. Yes. In his May 6, 2011 rebuttal testimony in the current Wyoming case, Mr. Duvall presented the same figures. Mr. Duvall testified as follows:

> Using hourly data from calendar year 2010, this calculation shows the company held 344 average MW of regulating reserves and 284 average MW of load following reserves. *Combining these two figures as a root sum square, consistent*

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[13] In Wyoming Public Service Commission Docket No. 20000-384-ER-10, Data Request WIEC 8.15 I requested the very information that Mr. Duvall presented in his rebuttal, and was told the Company could not produce it.

[14] Duvall Rebuttal, page 37, line 805.

[15] Id, page 38.

> *with the methodology implemented in the Wind Study, the total regulating margin comes to 447 average* MW.[16]

A footnote in this passage of Mr. Duvall's Wyoming testimony is very important, and it states as follows:

> It is not appropriate to sum regulation reserves and load following reserves. Combining the 10-minute regulation reserves and the 60-minute load following reserves as a root sum square recognizes that the two types of operating reserve demands are independent and not correlated.

Mr. Duvall now claims the same data supports a figure of 629 MW. This change is due to <u>summing</u> the figures together rather than combining the figures as a root sum-square as applied in the Wind Study, contradicting his earlier testimony.

The reasons for this change are not clear, but, Mr. Duvall's new analysis contained numerous errors and other problems. These include the fact that the underlying data used by Mr. Duvall represents the *difference between capacity on line and capacity dispatched, and not actual reserve allocations*. Indeed, Mr. Duvall testified to this fact in the 2009 GRC.[17] This is a particularly troubling problem for his calculation of load following reserves (or 60 minute reserves) because the great majority of the requirements now claimed by Mr. Duvall occur at night, when there is little reason to believe 60 minute reserves are needed for reliability purposes. Mr. Duvall is suggesting that the Company backs down its plants at night to set aside additional reserves for meeting sudden load spikes or changes in wind. In reality, it is far more plausible to assume that the plants are being backed down at night due to a lack of load or because their fuel cost exceeds the market price of energy. Further, even during the day time the backing down

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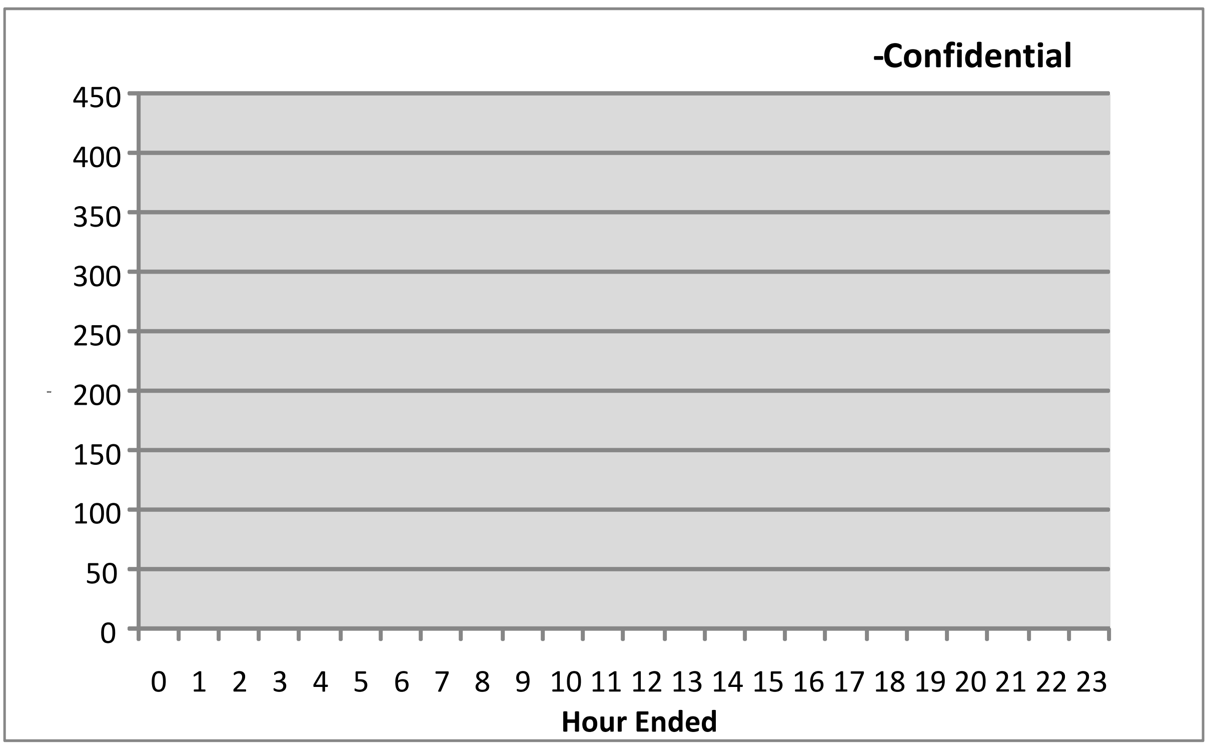
16 Rebuttal Testimony of Gregory N. Duvall, Wyoming Public Service Commission Docket No. 20000-384-ER-10, page 58. The footnote contained in the original document is provided above. Emphasis added.

17 No. 09-035-23, Rebuttal Testimony of Gregory N. Duvall, page 20, lines 431-434.

of coal plants could result from transmission constraints, derations or other issues. Consequently, it is highly questionable whether these claimed 'load following" reserves should be considered at all.

Q. DO YOU HAVE A GRAPH THAT ILLUSTRATES THIS POINT?

A. Yes. The figure below demonstrates this problem. Mr. Duvall contends the Company must set aside resources that can be called up within 60 minutes for purposes of meeting changes in load and wind output. However, the figure below shows that most of the 60 minute "load following" reserves computed by Mr. Duvall occur at night when load is lowest. This is a clear indication that his figures represent little more than idle capacity.



Q. ACCEPTING THE PREMISE OF LOAD FOLLOWING RESERVES AS VALID, ARE MR. DUVALL'S ACTUAL 2010 FIGURES OTHERWISE ACCURATE?

A. No. There are also numerous errors and inconsistencies in Mr. Duvall's analysis. The most serious error was a gross overstatement of load following reserves provided by

Currant Creek and Lake Side. When only one CT unit was running, Mr. Duvall assumed the potential reserve capacity included the capacity of the entire plant, including duct firing, even though less than half the nameplate capacity of the plant would be available for reserves. This is erroneous, because when a CT is not operating, it takes more than 60 minutes to return it to service and duct firing cannot be used at all.

For example, on January 1, 2010 at 5:00 AM, Mr. Duvall showed a Maximum Dependable Capacity for Lake Side of [redacted] MW. The loading of the plant at the time was [redacted] MW. This resulted in reserves available for load following and regulation of [redacted] MW in Mr. Duvall's calculations.[18] Some of this ([redacted] MW) was assigned to regulating margin based on data from the Company's Ranger PI system. As a result, Mr. Duvall determined the load following reserve was [redacted] MW. At the time, however, only one CT was running, so the maximum capacity of the plant available within one hour was really only [redacted] Based on a loading of [redacted] MW, this produces a maximum total reserve capability of [redacted] MW. Since [redacted] MW was assigned to regulating reserves the maximum load following reserve was only [redacted] MW. Mr. Duvall's figure was overstated by [redacted] MW.

These mistakes resulted from the thousands of hours in 2010 when the Company shut down one of the CTs at Currant Creek or Lake Side at night. Mr. Duvall's interpretation is that these units were idled to provide for reserves to meet load spikes or sudden changes in wind output. Since it takes two hours to restart the units (and there is a six hour minimum downtime) Mr. Duvall's computations make no sense at all. In reality, the plants were simply idled because they were not needed and cost more to run than the market price of energy.

[18] There is a 6 MW reduction to the total based on a minor ramp rate calculation that limits total reserves.

Q. WERE OTHER PROBLEMS APPARENT IN THE COMPANY DATA?

A. Yes. The Company used inaccurate and overstated data for the Cholla plant capacity. While Mr. Duvall contends steadfastly that Cholla can only provide 387 MW of capacity due to transmission constraints, when determining the actual 2010 reserves, his analysis assumed the unit could operate at 395 MW more than 6300 hours and in excess of 395 MW for 776 hours. For his GRID study Mr. Duvall limits Cholla by the transmission capability (387 MW), but he did not do so for the reserve analysis. This further overstates the reserves he has computed.

Further, the Company has a mistake in the Gadsby data showing these units providing regulating reserves hundreds of hours when they weren't even on line. This is simply incorrect.

Finally, for purposes of computing reserves, Mr. Duvall assumed Bear River produced [redacted] MW of reserve capability on average, and as much as [redacted] MW at times. In the Company's initial filing, Mr. Duvall assumed Bear River could provide only [redacted] MW of reserves. Mr. Duvall adopted OCS Adjustment 7.1, which increased the Bear River reserve capability to [redacted] MW. This is still well below the [redacted] MW reserve capability Mr. Duvall assumes in his 2010 actual reserve calculations. Correcting these errors reduces the reserve requirement computed by Mr. Duvall to 381 MW. When the spinning contingency reserves (13 MW) are counted, the result is 394 MW, well below the amount I included in GRID, based on my corrections to the Company's Wind Study. Table 2SR summarizes this analysis.

Table 2 SR
PacifiCorp Regulating and LF Reserves

		MW
1	OCS GRID Input Reg+LF Reserves	422
2	Actual 2010 Reg + LF Reserves	381
3	Spinning Contingency Reserves	13
4	Total Actual 2010 Reserve	394

Q. SUMMARIZE THESE POINTS.

A. Mr. Duvall has greatly overstated the actual 2010 reserve requirements. He has incorrectly counted hundreds of MW of reserves in his calculations and greatly exceeds the amounts he includes in GRID for the very same resources. For these reasons, his analysis is completely flawed. Correcting these errors alone reduces the load following reserve requirement to 164 MW, compared to Mr. Duvall's claimed result of 284 MW. If input to GRID using the root mean square formula it would result in 381 MW total, far less than I modeled in GRID. Consequently, correcting Mr. Duvall's figures results in validation of my modeling, even including the contingency reserves for wind generation.

Q. ARE THERE OTHER PROBLEMS IN MR. DUVALL'S ANALYSIS?

A. Yes. Based on the assumptions that Mr. Duvall uses to compute load following and regulating reserve, Mr. Duvall has not properly modeled these requirements in GRID. Mr. Duvall defines load following reserves as resource that are not available in ten minutes, but can be available within 60 minutes. Consequently, load following reserves should be modeled as a "ready reserve"[19] requirement in GRID, not as a "regulating reserve" requirement (which requires the resource be spinning). As a result, the Gadsby CTs could provide load following reserves at night, even if they were shut down. In fact,

[19] Ready reserve is capacity that can be called upon in ten minutes. Spinning (regulating) reserves must be available in less than ten minutes.

it makes no sense to model the Gadsby CTs as must run, because they can provide required ready reserves whether running or not. The must run modeling proposed by Mr. Duvall actually prevents the Gadsby CTs from providing ready reserves when needed.

The more costly regulating (ten minute) reserves modeled in GRID should be reduced from 533 MW to 344 MW based on Mr. Duvall's figures.[20] As noted above, the GRID ready reserve should be increased by 164 MW. When these changes are made to GRID, the net change in Total Company NPC is less than $900 thousand, as compared to my original adjustment, confirming its validity. Note that this analysis also includes the 5% contingency reserves in GRID based on Mr. Duvall's recommendation. Even accepting Mr. Duvall's reasoning, after correcting his errors, the 2010 actual data confirms my original modeling results.

<u>Adjustment OCS 2. Must Run Modeling</u>

Q. PLEASE COMMENT ON MR. DUVALL'S CONTENTION THAT THE PROPOSED MUST RUN MODELING OF CURRANT CREEK AND THE GADSBY CTS ACCURATELY SIMULATES ACTUAL OPERATIONS.

A. Mr. Duvall supports the "must run" assumption by claiming that the capacity factors for these units are consistent with actual (albeit outdated) 2009 results. He simply discounts the fact that the Gadsby CTs continue to shut down nearly every single night. He cites a capacity factor for the Gadsby CTs of 33% in 2009, and 65% for Currant Creek. However, 2010 results show the output of both plants has declined – the Gadsby CTs had a 24% capacity factor, while Currant Creek's was 52%.

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[20] Even this amount may be overstated because they are just the difference between plant capacity and plant loading as discussed earlier.

Mr. Duvall's reliance on the outdated capacity factor data is also overly simplistic. For example, he could produce GRID capacity factors that match the historical results by requiring the Gadsby CTs run fully loaded at night and shutting them down in the day time. Capacity factor, in isolation is not very meaningful.

Q. HAS HIS TESTIMONY LED YOU TO REEXAMINE ANY GRID INPUTS?

A. Yes. Review of the actual hourly generator logs for the Gadsby CTs supports a 20 MW minimum capacity rather than the 13 MW currently modeled in GRID. Exhibit OCS 4.3SR shows that nearly all of the operation of these units takes place at 20 MW or higher. The exact reason for this situation is not clear, but it is more appropriate to increase the minimum capacities for these units in GRID given these results. Once this is included in the OCS study (which reverses the must run requirement) GRID predicts an annual capacity factor for the Gadsby CTs of 22%. This compares quite well to the actual 2010 result of 24%. In contrast, the Company GRID study result of 32.8% would increase to more than 50% if the proper minimums for Gadsby were modeled. This clearly demonstrates that Mr. Duvall's proposed modeling for the Gadsby CTs is unsupported and erroneous. This change does, however, increase NPC and I recommend it be reflected in the test year as part of the adjustment that reverses the Gadsby CT must run.

Q. DO YOU AGREE WITH MR. DUVALL'S ARGUMENT FOR THE MUST RUN MODELING OF CURRANT CREEK?

A. No. Again the plant continues to cycle frequently, though not as frequently as in the past and often at least one CT is shut down at night. Further, the OCS modeling of the plant already assumes 7 months of must run operation based on the limited screening I have performed. Based on my results, the Currant Creek capacity factor in the test year is 41%, as compared to 52% actual. Given the sensitivity of the plant output to forward prices and the decreasing trend in capacity factor, this is reasonable.

Q. COMMENT ON MR. DUVALL'S ARGUMENT THAT THE MUST RUN MODELING OF THESE GAS UNITS IS NEEDED TO AVOID RESERVE SHORTAGES.

A. This argument is unsupported by the actual simulation results. As I noted in my direct testimony, the Company's PACW modeling in GRID frequently does show reserve shortages. Mr. Duvall has never corrected this problem, and even opposes any adjustments that address this problem, such as the hydro reserve optimization or the Chehalis reserve capability modeling. In any case, there is no consequential change in reserve shortage for PACE due to the OCS modeling. Overall the OCS wind integration modeling shows less than half the reserve shortages of the Company modeling because it reduces the PACW reserve shortages. Mr. Duvall ignores an obvious modeling error in PACW that produces reserve shortages, while focusing erroneously on a non-existent problem for PACE. Finally, the Company could address this issue by checking for reserve shortages in its screening adjustment rather than by simply forcing unrealistic and uneconomic modeling in GRID.

Q. HAVE YOU CHANGED YOUR RECOMMENDED FINAL NPC?

A. Yes. I have included the increase in the minimum capacity of Gadsby as part of the adjustments that reverses the must run modeling, reducing that adjustment by $813,341 as shown in Exhibit 4.1 SR.

Adjustment 5.2 Trading and Arbitrage Margins

Q. DOES MR. DUVALL DISPUTE THIS ADJUSTMENT?

A. Yes. Mr. Duvall argues that GRID already reflects arbitrage profits, though he never quantifies them. Mr. Duvall contends that at times, GRID shows simultaneous purchases and sales, which he equates to arbitrage. This is incorrect because simultaneous transactions may be due to balancing needs, not arbitrage. For example, a purchase in Mid C for balancing purposes may occur at the same time when sales are being made to 4 Corners. That does not imply, however, that the transaction was arbitrage. However, I do concede that GRID has some arbitrage built in for balancing purposes. I recommend that the Commission accept Adjustment 5.2 as regulators in other states have already done, but allow the Company to eliminate the adjustment in a future case, if it can show that the amount of arbitrage already included in GRID offsets any need for this adjustment.

Finally, as I will point out shortly, the Company's evaluation of the Centralia Point to Point contract issue also has implications for this issue, as the Company assumed the Centralia contract would enable it to obtain substantial arbitrage profits.

Adjustment 6.1 Evergreen Contract

Q. MR. DUVALL VIEWS THIS ADJUSTMENT AS CONTRADICTORY TO THE COMPANY'S MODELING OF OUTAGE RATES FOR NEW THERMAL PLANTS WHICH YOU HAVE PREVIOUSLY ACCEPTED. DO YOU AGREE?

A. No. The modeling of new resources is not based on contractual estimates, but rather on average outage rates for mature plants. Therefore it is not analogous to a new contract, such as Evergreen.

Adjustment 6.3 APS Screening Adjustment

Q. MR. DUVALL OPPOSES THIS ADJUSTMENT ON THE BASIS THAT IN THE 2007 CASE, THE COMMISSION ADOPTED MONTHLY SCREENS FOR CALL OPTION PURCHASES. IS THIS CORRECT?

A. Mr. Duvall's testimony is wrong about this once again.[21] In Docket 07-093-35, the Commission adopted the CCS call option adjustment of $.923 million on page 22 of the Final Order. The .923 million was supported by Exhibit CCS 4.7 from that case. This exhibit showed the number of <u>uneconomic days</u> of operation for each of the call options based on a <u>daily</u> screening analysis. This analysis was provided to the Company in the workpapers in that case. The prior case order does not provide justification for monthly screens. Since the Company has been using daily screens for the thermal plants there is no reason to use monthly screens for contracts.

Adjustment OCS 8.1 Lewis River Hydro Modeling

Q. DOES MR. DUVALL OPPOSE THIS ADJUSTMENT?

A. Yes. In his summary, on page 24 he contends that the adjustment shifts generation to times when the units are off line. He does not explain that claim later on page 103 where he provides a more detailed discussion of the issue. There is no time when Swift 1 is offline. In OCS 33.6 the Company contends that Mr. Duvall was discussing the outage of a single turbine at the plant. However, as pointed out in my testimony concerning outage rates, the Company has no basis for selecting any particular period as time when a random forced outage would occur. The energy lost due to outages is factored into my analysis, and the impact of moving generation out of the period in questions would be inconsequential- less than $60,000 on a Total Company basis. This figure only applies to

[21] Mr. Duvall made the same incorrect claim in the 2008 case (Duvall rebuttal, page 5).

the impact of the rescheduling of hydro to optimize reserves (estimated to be worth $1.5 million for Swift 1 in my original testimony) not the actual value of Adjustment OCS 8.1, which is based on reversing the Company's Lewis River modeling adjustments.

Mr. Duvall's primary criticism is that the Lewis River adjustments are "legitimate" and haven't been challenged on their merits. However, he has made no substantive challenge to the alternative of modeling the reserve optimization in GRID, aside from the erroneous criticism addressed above. As a result, there is no reason for the Commission to not adopt the hydro optimization adjustment. If fully implemented this would likely exceed the impact of the Lewis River adjustments, which provides the basis for the adjustment. The Commission should either remove the Lewis River adjustments entirely, or require the Company to optimize all hydro storage resources in the final GRID run using the methodology I proposed. Either approach would be a reasonable outcome.

Adjustment OCS 9.1 Hydro Outage Rate Adjustment.

Q. DOES THIS ADJUSTMENT REMAIN IN DISPUTE?

A. The Company has adopted the part of this adjustment related to coordinating the thermal and hydro outage rate base periods. Mr. Duvall continues to dispute the portion of the adjustment related to what he characterizes as removal of the hydro outage rates.

Q. WHAT ARE MR. DUVALL'S OBJECTIONS TO THE REMAINDER OF THIS ADJUSTMENT?

A. Mr. Duvall contends that some of the energy lost during outages is spilled. However, the Company has not done any analysis to determine how much energy was lost due to spillage during the base period. Based on the data Mr. Duvall cites from OCS 20.9, only

19% of the energy lost during outages was spilled (10,399/54495) At most this would justify discounting the adjustment by 19%. I accept this criticism and reduce the adjustment accordingly, even though the Company did suggest in OCS 20.9 that most of the spillage only occurred due to abnormally heavy rainfall, something that would not occur during median hydro conditions.

Mr. Duvall also argues that it is not proper to assume that revenue resulting from rescheduling occurs at random times, because hydro usage is mainly on peak. That's quite true. By assuming the energy is rescheduled to a later hour with only the average market value, I have actually understated the adjustment by overstating the loss in revenue. Since hydro is preferentially scheduled to higher value periods, it would also be likely that after an outage the Company would try to reschedule the energy to higher value periods, and lose less revenue than I assumed. Thus, Mr. Duvall's criticism really implies the adjustment is too small not too large.

Adjustments OCS 10.1, 10.2 and 10.3 Cal ISO, DC Intertie and Centralia Contracts

Q. DOES THE COMPANY AGREE WITH YOUR PROPOSAL TO REMOVE THESE CONTRACTS AND THEIR RELATED COSTS FROM GRID?

A. No. In the case of the Cal ISO charges, Mr. Duvall argues that removing the costs would discourage the Company from doing future business with the Cal ISO. This argument is unpersuasive for at least three reasons. First, the Company enters into transactions with the Cal ISO on an opportunistic basis- i.e. the benefits of a Cal ISO enabled transaction exceed the costs. The Company has always acknowledged that these transactions occur close in time to actual operations, and are, for that reason, seldom part of the projected test year. Second, the Company's approach to Cal ISO would be comparable to modeling STF transaction costs, but no STF energy in the test year. Mr. Duvall could just as well claim that unless the STF costs were included in the test year, the Company would be discouraged from buying STF energy. Finally, regulators in Idaho have already rejected Mr. Duvall's argument:

> The issue is what should be included in base rates. The reduced amount included in base rates does not assume the Company will not do business with Cal ISO as a counterparty. Transaction data should have been provided if the Company intended this to be a continuing forward expense. The Commission accepts the adjustment. If Cal ISO wheeling and service fees are incurred, the Company should seek recovery of costs in the ECAM. (Idaho Public Utilities Commission, Docket No. PAC-E-10-07, Order No. 32196, Pages 31-32.)

Q. WHAT IS MR. DUVALL'S POSITION REGARDING THE DC INTERTIE?

A. Mr. Duvall argued the contract was prudent when originally negotiated and that it continues to be used to transfer energy from summer-peaking California to the winter-peaking Pacific Northwest. He asserted, but does not document, that capacity benefits are provided by the contract. Mr. Duvall's arguments also seemed to contradict various discovery responses[22,23,24] which described the purchases made available from the DC Intertie as seldom used, high cost resources which are not expected to be used under normalized conditions. The fact remains that during a recent 12 month period,[25] the contract provided less than an average of 6 MW of power for ratepayers. Further, the Company has produced no documents supporting the original prudence of the contract[26] or of its subsequent management of the contract.[27] Finally, the Company acknowledges

22 Wyoming Docket 20000-389-EP-11 WIEC 1.45
23 Wyoming Docket 20000-384-ER-10, WIEC 1.72
24 WUTC Docket No. UE-100749, Response to ICNU DR 10.3
25 The twelve months ended November 30, 2010.
26 Wyoming Docket 20000-389-EP-11 WIEC 1.46, 1.47 and 1.49.
27 Id. See also Docket 20000-384-ER-10 WIEC 1.73

that short-term firm transmission is available for the same path and that it has used these resources from time to time.[28]

Q. COMMENT ON MR. DUVALL'S CLAIM OF CAPACITY BENEFITS ATTRIBUTABLE TO THE DC INTERTIE CONTRACT.

A. Mr. Duvall contends that absent the DC Intertie (costing $2.08/kW Month) the Company would need to make purchases from BPA at $8/kW month. He provides no basis for this claim, but it appears highly questionable and is contradicted by the actual utilization of the contract. First, 85% of the meager DC Intertie deliveries occur in only a 4 month winter period, so the Company would not need to incur the cost of replacement purchases every month. Second, in the highest utilization month (December), the Company only purchased an average of 31 MW, not the full 200 MW offered under the contract. Indeed, even in December, utilization was only at a 15% load factor. Every other month used far less of the available capacity. Third, there is no reason to believe the BPA purchase would be the most economical alternative. STF contracts may be lower in cost. Finally, all of the purchases made using the DC Intertie were <u>spot</u> purchases. It lacks credibility to assert, that there is a need for capacity when the Company waits until only an hour or two ahead of time to make these purchases. It is not reasonable to believe the Company counts on spot purchases made only an hour or so in advance to provide capacity needed for reliability purposes.

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[28] Wyoming Docket 20000-389-EP-11 WIEC 12.15

Q. HOW DID MR. DUVALL TRY TO JUSTIFY THE CENTRALIA POINT TO POINT CONTRACT?

A. Mr. Duvall again contends the contract was prudent. He claimed there was once a need for capacity to allow for a [redacted] MW purchase from TransAlta. The problems with this argument are numerous. First, even if true, the TransAlta purchase could only justify about [redacted] of the Centralia Point to Point capacity. Second, and more important, the TransAlta contract was an exchange agreement that provided no net delivery of energy to PacifiCorp. Every hour the Company purchased 200 MW from TransAlta at one location and resold the same amount of power at another location back to TransAlta. The contract was really nothing more than a transfer of power for TransAlta, and was not used for or needed to serve PacifiCorp loads. Third, the economics of the transaction are simply not sufficient to justify the Centralia Point to Point contract. On an annual basis, the Company paid $11.5 million for the Centralia Point to Point contract, but received only $1.6 million in net payments from TransAlta. Finally, the TransAlta contract expired at the end of 2010, and therefore provides no justification for continuation of the contract into the June, 2012 test year. Since the TransAlta deal was signed around the same time as the Centralia Point to Point contract, questions regarding the prudence of this transmission contract become all the more obvious.

In the concurrent Wyoming GRC, Mr. Duvall also attempted to justify the contract on the basis that some of it has been sold to other parties. For the 12 months ended November, 2010 period, the Company only received $2.95 million in revenue from such sales.[29] While the amount was available to the Company before the filing in this case, they have not reflected these amounts in the test year. If the Commission does allow the Centralia contract to be included in rates, it should at least make this offset to the test year.

Q. WHY DID THE COMPANY EXECUTE THIS CONTRACT IN 2007?

A. Mr. Duvall presents an analysis conducted in 2007, Exhibit GND-4, which addresses this issue. Mr. Duvall cites an assumed benefit of [redacted] million related to avoiding unmet energy costs. However, this amount is highly questionable. [redacted]

> [redacted][30][redacted]

[redacted]

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[29] Wyoming Docket No. 20000-389-EP-11, WIEC 12.14.

[30] [redacted] (Footnote in original document)

[redacted]

Finally, the Company's Apex testimony contradicts its testimony regarding the Centralia Point to Point contract. In the matter of the Apex plant, the Company has clearly argued than projections of unmet energy don't provide a reasonable basis for resource selection, and even eliminated it from consideration of the Apex option.[31] It is interesting that Mr. Duvall's comments on page 119 of his rebuttal regarding a study favorable to Apex (which he criticizes) seems to parallel the study the Company now uses to support the Centralia Point to Point contract. Mr. Duvall criticized the assumption of using Apex to meet unmet load based on artificially high market prices and excluding certain resources. This is a similar study design the Company used in the case of the Centralia Point to Point contract.

Q. DOES EXHIBIT GND-4 DEMONSTRATE ANY OTHER REASONS WHY THE COMPANY ENTERED INTO THE AGREEMENT?

A. [redacted][32]

[redacted]

[31] Utah Docket No. 10-035-126, Public record testimony of Richard S. Hahn, March 24, 2011, page 10. Mr. Hahn testified that the Company proposed removing unmet energy from its analysis of a resource option it did not end up selecting.

[32] See Docket 2000-384-ER-10, WIEC 42.58.

[redacted]

Q. WHAT IS YOUR RECOMMENDATION?

A. These contracts should be removed from the test year. They are not necessary or economical. Further, the prudence of the Company's inaction related to these contracts is highly questionable.

<u>OCS Adjustment 11.1 – Non-Firm Transmission Modeling</u>

Q. EXPLAIN THE BASIS FOR MR. DUVALL'S OPPOSITION TO USE OF THE COMMISSION APPROVED MODELING OF NON-FIRM TRANSMISSION.

A. Mr. Duvall provides no additional evidence or analysis. He merely asserts that GRID cannot capture all of the costs of the non-firm transmission, nor the Company's utilization of it. However, GRID models only about 36% of the non-firm transmission utilization that actually occurs, while Mr. Duvall would like to include 100% of the cost.

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[33] See OPUC order, 07-446, pg. 9.

Q. MR. DUVALL CONTENDS THE PURCHASE OF NON-FIRM TRANSMISSION IS DONE IN THE SAME MANNER AS PURCHASES OF STF TRANSMISSION. PLEASE COMMENT.

A. This statement really says nothing. The Company may make the purchases with the same people in the same manner. However, the products and purposes are much different. Non-firm transmission is almost always purchased shortly before utilization and cannot be counted on for reliability purposes. It is a spot purchase. Therefore, it should only be purchased if the cost is less than the perceived value. Non-firm transmission is an opportunity purchase, while STF transmission may be done to meet requirements. In the former case, there is an economic trade-off between the purchase made and value received, suggesting the cost should be modeled on a variable costs basis, the same as hourly balancing transactions are modeled. In the latter case (STF transmission), the need to provide for firm service is overarching, suggesting that modeling the cost on a fixed basis could be reasonable. Mr. Duvall's contention that NF transmission is used to meet load obligations is misleading and implausible, for it suggests the Company waits each hour to see if there is non-firm transmission going to be available to serve its load. Again, ascribing capacity benefits to spot purchases of either transmission or generation is simply not reasonable.

<u>OCS Adjustment 15.1 Chehalis Reserve Capability</u>

Q. DOES MR. DUVALL CONTINUE TO DISPUTE THIS ADJUSTMENT?

A. Yes, but his arguments do little more than restate issues already addressed in my direct testimony. However, he does acknowledge that BPA recently granted the Company's Request for Access to Dynamic Transfer Capability. Confidential Exhibit OCS 4.4SR is a copy of two confidential BPA documents granting the Company request. The documents state the intended use was [redacted] Mr. Duvall acknowledges that the capability could be established by October, 2011 and that the Company continues to work with BPA to implement a complete solution. Absent a disallowance by the Commission, the Company will have little incentive to actually implement the capability as 70% of the cost of not doing so will flow through the EBA. Further, prudence provides another basis for accepting this adjustment.

Q. DOES THE BPA DOCUMENT CLARIFY ANY OTHER MATTERS?

A. Yes. It shows a ramp rate for Chehalis of [redacted]/minute. The Company normally determines the reserve capability by determining the ten minute ramp rate, which would equate to [redacted] This demonstrates that the [redacted] MW figure used by Mr. Evans and me is conservative. It is interesting that Mr. Duvall appears to criticize Mr. Evans figure, while not revealing that the correct figure is actually higher.

<u>OCS Adjustment 16.1 Station Service Corrections</u>

Q. PLEASE DISCUSS THIS ISSUE.

A. The Company agrees to implement OCS proposed corrections to the Hunter portion of this adjustment. This is about 1/3 of the adjustment.

This leaves the Chehalis and Currant Creek modeling portion in dispute. For Chehalis, Mr. Duvall has not addressed the discrepancy between the Lewis County PUD billing charges and the charges stemming from the actual generator logs. Since the Company will cease to purchase Station Service from Lewis County in the test year, the generator logs are more relevant going forward.

As for Currant Creek, it is important to recognize that the station service requirement we are discussing is the non-running requirement only. When the units are running, the heat rate curve already reflects the station service. The Company models Currant Creek as a must run resource, therefore it should not model non-running model station service for the plant. Mr. Duvall wishes to compute the station service on the basis of *prior* operation when the unit cycled quite often, rather than the expected test year operation where the plant will either not cycle at all (as per the Company modeling) or cycle far less often (as per the OCS modeling.) As for Mr. Duvall's arguments regarding forced outages contributing the non-running station service, the impact is minor because the Currant Creek outage rate is quite low.

If the Commission accepts the Company's must run assumption for Currant Creek (rejecting OCS 2.2), the full station service Adjustment (OCS 16.1) is appropriate. If OCS 2.2 is adopted (reversing the Currant Creek must run 5 months of the year) OCS 16.1 should be reduced by $18,264 on a Utah basis. In the compliance GRID run, the Company should make an appropriate adjustment depending on the Commission's decision regarding the issue.

OCS Adjustment 18.1 Major Market Caps

Q. DOES MR. DUVALL DISAGREE WITH THE OCS MARKET CAP ADJUSTMENT?

A. Yes. Mr. Duvall presents no new analysis, and bases his response on various unsupported assertions, mainly regarding market liquidity and the impact of wind integration on coal generation. Mr. Duvall does not provide any data to support the continuing claim that there are liquidity constraints in peak hours. He provides no new evidence to suggest that modification of the market caps is necessary. In fact, he does not present evidence that the market caps are even relevant. He also pays little attention to the fact that the OCS adjustment is fundamentally different from the DPU and UIEC adjustments in that it preserves the limitations in the graveyard shift period already accepted by the Company and Commission for many years.

Q. ARE THERE ANY OTHER PROBLEMS IN MR. DUVALL'S DISCUSSION OF MARKET CAPS?

A. Mr. Duvall asserts that absent the increases in wind integration requirements, without the market caps proposed by the Company coal generation would be excessive. However, this apparently depends on accepting the Company's overstated and discredited wind integration analyses. In fact, no conclusions can be drawn from the analysis he refers to for this reason.

Q. MR. DUVALL CRITICIZED YOUR ADJUSTMENT ON THE BASIS THAT YOU HAVE NOT DEMONSTRATED THE COMPANY'S DETERMINATION OF MARKET LIQUIDITY IS INCORRECT. PLEASE COMMENT.

A. It is impossible to address something that doesn't exist. Mr. Duvall has made absolutely no determination of market liquidity or illiquidity. Instead he merely continues to *assert* that lack of market liquidity prevents the Company from making sales every hour of the year. He completely ignores the possibility that sales are inhibited by plant outages, derations, market prices, or transmission constraints already being modeled in GRID. In the final order in the last case, the Commission required the Company to demonstrate that market caps continue to be relevant. The Company failed to do so, but instead expanded the concept to apply every single hour of the year. The Company did so without a single bit of evidence concerning the actual issue of market liquidity.

<u>OCS Outage Rate Adjustments 21.1-21.6</u>

Q. DOES THE COMPANY AGREE WITH ANY OF THESE ADJUSTMENTS?

A. No. However, the record is rather complete on these issues, so I won't belabor the point. There are a number of instances where Mr. Duvall has mischaracterized my prior testimony regarding these matters, which I will address.

Q. DOES YOUR PRIOR AGREEMENT TO USE THE $EFOR_d$ FORMULA INVALIDATE THE RESERVE SHUTDOWN HOUR ADJUSTMENT?

A. No. The $EFOR_d$ formula is applied only to peaking units, based originally on a *stipulation* in another state. For peaking plants I agree it's the best formula to use and did not apply the reserve shutdown adjustment to those units. $EFOR_d$ could be applied to any plant, but is most relevant for resources with a significant number of reserve shutdown hours.[34] I would not object to expanding use of the $EFOR_d$ formula to other plants to resolve the issue of reserve shutdown hours. The exclusion of reserve shutdown hours from the outage rate is a short cut intended to accomplish the same thing as use of the $EFOR_d$.

Q. DOES YOUR PRIOR TESTIMONY REGARDING THE MODELING OF THE IMPACT ON OUTAGE RATES OF CAPITAL INVESTMENTS VIS A VIS THE USE OF A FOUR YEAR AVERAGE CONTRADICT YOUR CURRENT PROPOSAL RELATED TO CHOLLA 4?

A. No. The testimony Mr. Duvall quoted dealt with new, large capital scale investments. The matter originated in the Oregon case he cites because one of the parties wanted to

[34] $EFOR_d$ becomes comparable to the PacifiCorp formula when there are no reserve shutdown hours.

make an adjustment to reduce outage rates because Portland General Electric had invested in a simulation system that was supposed to improve operational reliability. As can be seen from the passage he quoted, my primary objection was related to the problem of discerning the impact of a major new investment, such as the simulator, or a scrubber. There is really no way to know what the impact would be on reliability stemming from a new system. In this case, we are not dealing with a major new capital addition, but rather with a routine repair that solved a longstanding problem that is no longer expected to occur. In this instance we know exactly how much output was lost due to the problem, so it is not a difficult problem to estimate the impact on outage rates. This is much different from a situation where a major upgrade or new system has been installed. Finally, it is worth noting that in the above referenced Oregon case, Mr. Duvall and I both supported a stipulation that stated the issue of outage rate impacts of plant additions would be dealt with on a case by case basis.

Q. MR. DUVALL ALSO SUGGESTS THAT YOUR 2002 WYOMING TESTIMONY CONTRADICTS YOUR PROPOSAL TO EXCLUDE EXTREME OUTAGES IN THIS CASE. PLEASE COMMENT.

A. A careful reading of the passage from the Wyoming order which Mr. Duvall quotes reveals the reasons why that testimony is not applicable to the current situation. In the Wyoming case, the Company did not then have any EBA, or PCAM mechanism to recover outage costs. In fact, my actual testimony stated that use of the four year average effectively amortized outage costs and allowed recovery over a four year period. I made the proposal because it was the only way in which the Company could recover costs of the Hunter outages because the Wyoming Commission had already turned down a request for a deferral mechanism. Now, PacifiCorp has an EBA in Utah and therefore, the focus changes from recovery of past costs, to producing the best forecast of future costs. The EBA will recover costs related to unusual outages, and likewise reward the Company for unusually good performance. The NPC baseline should be set to provide the best forecast of future costs, rather than to facilitate the collection of prior costs.

<u>OCS Adjustment 22.1 Heat Rate Modeling</u>

Q. TWO REGULATORY COMMISSIONS HAVE NOW ADOPTED THIS TYPE OF MODELING ADJUSTMENT, YET MR. DUVALL CONTINUES TO OPPOSE IT. PLEASE DISCUSS HIS TESTIMONY.

A. In this case, his testimony is contradictory and incorrect. First, on page 91, line 1957 he mischaracterizes my testimony as suggesting the adjustment is *only* proper when applied at the top of the heat rate curve. While I did only apply the adjustment to the top of the heat rate curve, I did not state it was only applicable at that point on the curve. Indeed, all I said was that both the Company and I agree at least to the applicability of the adjustment at the top of the heat rate curve.

Next, on page 92, Mr. Duvall states that while my *example* applies only to the top of the heat rate curve, my proposed *adjustment* applies to the *entire* curve. Again, this is incorrect, because I only applied the adjustment at the top of the curve. This should have been apparent from my testimony and workpapers. In this instance, it appears Mr. Duvall is addressing the full adjustment which was applied in other states, not my proposal in this case.

Finally, on the same page, Mr. Duvall objects to the modeling of outage rates for gas plants in the analysis. Mr. Duvall states I should have not assumed all outages for gas plants were full forced outages. This criticism is nearly irrelevant. In GRID, Gadsby, Currant Creek and Lake Side virtually never run at full loading, and the entire adjustment as applied to those units is inconsequential ($752). For Hermiston the outage rates used reflected actual outage events and showed virtually no energy was lost due to partial outages. As Hermiston is the only mature plant with four years of actual data available, it was assumed the other plants would show a similar relationship between full and partial outages. In any case, I have no objection to using the actual data for the other plants if the Company cares to include it in the final GRID run. The only plant for which Mr. Duvall's criticism has any validity is Chehalis, and the impact of modeling partial outages for Chehalis is $38,940 on a Utah basis. I have reflected this amount in the adjustment shown on OCS 4.1S.

Q. MR. DUVALL TESTIFIES ON PAGE 92 THAT "THE COMMISSION REJECTED SIMILAR ADJUSTMENTS IN THE 2009 GRC AND THERE IS NO BASIS FOR RECONSIDERING THAT OUTCOME." DO YOU AGREE?

A. No. Mr. Duvall is ignoring the fact that the Commission itself specifically set aside this issue for further analysis and consideration:

> *We find this issue continues to warrant further investigation* prior to making any adjustments to the Company's modeling. We have concerns with both approaches but will again accept the Company's approach in this case. *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. (Final Order Docket No. 09-035-23, page 57. emphasis added)

While I have attempted to address the Commission's order in the prior case by analyzing actual operational data for Colstrip, presenting an alternative analysis attempting to work with other parties to examine this matter, Mr. Duvall has chosen to ignore each and every element of the Commission’s order and he walked away from the process initiated by the DPU to help resolve this issue.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.