

**REDACTED**

Docket No. UE-227

Exhibit PPL/105

Witness: Gregory N. Duvall

**BEFORE THE PUBLIC UTILITY COMMISSION  
OF THE STATE OF OREGON**

**PACIFICORP**

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**Redacted Rebuttal Testimony of Gregory N. Duvall**

**July 2011**

1 **Q. Are you the same Gregory N. Duvall who previously submitted testimony in**  
2 **this proceeding on behalf of PacifiCorp d/b/a Pacific Power (the Company)?**

3 A. Yes.

4 **Summary of Testimony**

5 **Q. What is the purpose of your testimony?**

6 A. My testimony has two parts: a Transition Adjustment Mechanism (TAM) update  
7 section, consistent with the TAM Guidelines adopted by the Commission in Order  
8 No. 09-271, and a rebuttal section responding to the parties' proposed  
9 adjustments.

10 First, in the TAM update section, I provide contract, fuel, and forward  
11 price updates to the Company's March 17, 2011 filing (Initial Filing). In addition,  
12 I explain the reasonableness of the Company's revised system net power costs  
13 (NPC) of \$1.563 billion, a number that reflects the TAM updates and adjustments  
14 for the test period of the 12 months ending December 31, 2012.

15 Second, in the rebuttal section of my testimony, I respond to the  
16 adjustments and criticism of the Company's NPC presented by Messrs. Ed  
17 Durrenberger and Brian Bahr on behalf of Commission Staff (Staff), Mr. Donald  
18 Schoenbeck on behalf of the Industrial Customers of Northwest Utilities (ICNU),  
19 Messrs. Robert Jenks and Gordon Feighner on behalf of the Citizens' Utility  
20 Board of Oregon (CUB), and Mr. Kevin Higgins on behalf of Noble Americas  
21 Energy Solutions, LLC (NAES).

22 **Q. Do other PacifiCorp witnesses address certain issues raised by the parties?**

23 A. Yes. Mr. Stefan A. Bird responds to CUB's and ICNU's adjustments related to

1 the Company's natural gas hedging; Mr. Rick T. Link responds to ICNU's  
2 adjustments and proposals related to the forward price curve; and Mr. William R.  
3 Griffith responds to ICNU's proposed adjustment to recognize non-NPC revenue  
4 in the TAM.

5 **Recommendation for Company's Net Power Costs for this Case**

6 **Q. In your direct testimony, you recommended that the Commission set the**  
7 **Company's system NPC at \$1.558 billion for the test period ending December**  
8 **31, 2012. Has your NPC recommendation changed?**

9 A. Yes. The Company has increased its recommended system NPC to \$1.563 billion  
10 or \$25.05 per MWh.

11 **Q. Why have you increased your system NPC recommendation to \$1.563**  
12 **billion?**

13 A. First, consistent with the TAM Guidelines, the Company updated the Initial  
14 Filing with (1) the most recent forward price curve and (2) new power, fuel, and  
15 transportation/transmission contracts and updates to existing contracts. Second,  
16 the Company has reviewed the proposed adjustments from Staff and intervenors.  
17 As discussed below, the Company has reflected certain of these adjustments in  
18 NPC. These factors result in a net increase to system NPC of \$5.0 million.

19 **Q. Please explain the change in NPC from the Initial Filing on an Oregon-**  
20 **allocated basis.**

21 A. As illustrated in Exhibit PPL/106, on an Oregon-allocated basis, the Company's  
22 forecast normalized NPC for calendar year 2012 are approximately \$384 million.  
23 This results in a \$1.8 million increase from the Initial Filing.

1 **Q. Does total Company NPC of \$1.563 billion produce a reasonable result in this**  
2 **case?**

3 A. Yes. As stated above, under the TAM Guidelines, the updated NPC reflect the  
4 most recent information available to the Company in the determination of 2012  
5 NPC.

#### 6 **NPC Updates**

7 **Q. Please describe how the Company updated NPC.**

8 A. Section B of the TAM Guidelines sets forth the elements of NPC that the  
9 Company will update in its Rebuttal Filing: the most recent forward price curve  
10 and new power, fuel, and transportation/transmission contracts, and updates to  
11 existing contracts.<sup>1</sup> The Company has updated NPC in this filing to reflect the  
12 most recent official forward price curve dated June 30, 2011. This update also  
13 includes prices for indexed contracts, mark-to-market value of natural gas and  
14 power swaps, as well as reshaped hydro generation. The Company also updated  
15 NPC to reflect new power, fuel, and transmission/transportation contracts and  
16 updates to existing contracts. Exhibit PPL/107 provides a summary of the impact  
17 on total Company NPC for each of the items.

#### 18 **Adjustments Accepted by the Company**

19 **Q. Please describe the adjustments proposed by Staff, CUB, or ICNU that the**  
20 **Company has accepted.**

21 A. The Company has accepted the following proposed adjustments:

- 22 • Bear River Normalization: Because of the significant change in weather  
23 conditions impacting the Bear River project, the Company accepts Staff's

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<sup>1</sup> See Order No. 09-274 at Appendix A at pp. 2-3.

1 and ICNU's proposed update to the modeling of Bear River median  
2 generation to include flood control years. This adjustment reduces system  
3 NPC by \$2.1 million.

- 4 • Calculation of the Transition Adjustment: The Company accepts NAES'  
5 proposal to continue to apply the changes to the Schedule 294 and 295  
6 rates that were adopted in Paragraph 15 of the stipulation adopted in Order  
7 No. 08-543 in UE 199 and in Paragraph 15(a) of the stipulation adopted in  
8 Order No. 09-432 in UE 207. The Company does not agree, however, to  
9 NAES' Bonneville Power Administration (BPA) transmission credit  
10 proposal.

11 **Q. Are there additional proposals from parties that the Company is adopting?**

12 A. Yes. Staff argues that the proposed BPA rate increase should not be included in  
13 the TAM unless the rate is adopted by BPA during the course of the TAM. Staff  
14 proposes an adjustment of \$22,000, Oregon allocated. Staff states: "Should the  
15 rate change be adopted during the course of the TAM Staff will revise this  
16 adjustment accordingly."<sup>2</sup>

17 **Q. How do you respond?**

18 A. The Company agrees with Staff that this updated rate should not be included in  
19 the TAM unless it is adopted by BPA prior to the final updates. Although my  
20 direct testimony in this case stated that the Company had incorporated the new  
21 proposed wind integration charge, that testimony was inaccurate, therefore the  
22 adjustment is not necessary. The NPC in the Initial Filing reflected the current  
23 \$1.29/kW-month charge, not the proposed \$1.32/kW-month charge.

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<sup>2</sup> See Staff/100, Durrenberger/4, lines 13-15.

1                   Nonetheless, BPA issued its Record of Decision (ROD) revising the  
2 charge on July 26, 2011. However, the Company had already finalized NPC for  
3 the update filing by this time. The Company is in the process of reviewing the  
4 new ROD and will incorporate the new charges in the November update,  
5 consistent with Staff's position.

## 6 **Company Responses to Contested Adjustments**

### 7 **Hedging**

8 **Q.     What is the purpose of your rebuttal testimony on hedging?**

9 A.     My rebuttal testimony supports the rebuttal testimony of Mr. Bird, which provides  
10 an overview of the Company's risk management policy and hedging program and  
11 demonstrates that there is no basis for CUB's and ICNU's proposed prudence  
12 disallowance related to the Company's hedging program. Specifically, I  
13 demonstrate that, over the course of the last several years, the Company's hedging  
14 program has reduced both the volatility and overall level of NPC.

### 15 **The Company's Hedging Program Reduces Volatility**

16 **Q.     How does the Company's hedging strategy benefit Oregon customers?**

17 A.     The Company's hedging strategy mitigates the volatility of NPC and protects  
18 against large swings in NPC as a result of unforeseeable changes in wholesale  
19 market prices for electricity and natural gas. Mr. Bird's testimony discusses  
20 Staff's 2005 Natural Gas Procurement Study, and its finding that PacifiCorp's  
21 hedging program reduced volatility by 82 percent from 1999-2004. Using the  
22 same methodology employed in that study for the period 2005-2010, I  
23 demonstrate that the Company's hedging of natural gas reduced the volatility of

1 gas prices by 50 percent, and reduced the volatility of wholesale power prices by  
2 52 percent as shown in Tables 1 and 2.<sup>3</sup>

**Table 1 – Natural Gas**

Hub/Pricing Point	PacifiCorp		Market Index		Increase (decrease) in Price	Reduction (increase) in Volatility
	Average (\$/MMBtu)	Coefficient of Variation	Average (\$/MMBtu)	Coefficient of Variation		
Rockies	\$5.91	0.19	\$4.97	0.42	16%	56%
AECO	\$3.41	0.09	\$5.18	0.35	-52%	73%
Sumas	\$7.44	0.18	\$5.67	0.40	24%	56%
Henry Hub	\$4.97	0.26	\$6.39	0.41	-29%	36%
<b>Overall</b>	<b>\$5.12</b>	<b>0.17</b>	<b>\$5.68</b>	<b>0.35</b>	<b>-11%</b>	<b>50%</b>

**Table 2 - Power**

Hub/Pricing Point	PacifiCorp		Market Index		Increase (decrease) in Price	Reduction (increase) in Volatility
	Average	Coefficient of Variation	Average	Coefficient of Variation		
4C HLH	\$65	0.18	\$57	0.37	13%	52%
4C LLH	\$46	0.15	\$39	0.36	14%	58%
MID-C HLH	\$59	0.18	\$51	0.33	14%	46%
MID-C LLH	\$47	0.25	\$41	0.38	13%	34%
<b>Overall</b>	<b>\$57</b>	<b>0.16</b>	<b>\$49</b>	<b>0.34</b>	<b>13%</b>	<b>52%</b>

3 **Q. Has the Company developed additional analysis on the issue of NPC**  
4 **volatility and hedging?**

5 **A.** Yes. The Company’s 2011 Integrated Resource Plan (IRP) addresses this issue  
6 and demonstrates that the Company’s portfolio approach to hedging, which is  
7 both comprehensive and integrated from a power/natural gas standpoint, reduces  
8 the volatility of NPC. First, the IRP demonstrated that the “less hedged portfolio

<sup>3</sup> The coefficient of variation is the standard deviation of a sample divided by its average. It allows for apples to apples comparisons of volatility, as it standardizes the scale of the samples.

1 shows a wider distribution of outcomes representing a higher risk to price  
2 changes. Similarly, the more hedged portfolio shows a narrower distribution.”  
3 Second, the analysis showed that “[t]he ‘hedge only power’ portfolio shows a  
4 much wider distribution due to the severe reduction in the natural offset between  
5 power and natural gas in the reference portfolio. The ‘hedge only natural gas’ has  
6 a similar distribution.”<sup>4</sup>

7 **Historical Benefits of Hedging in Company’s Net Power Costs**

8 **Q. Have you analyzed the historical impact of the Company’s hedging program**  
9 **on NPC in Oregon rates?**

10 A. Yes. I have prepared Exhibit PPL/108 which sets forth the impact of the  
11 Company’s hedging program on NPC in Oregon rates.

12 **Q. Please summarize the results of your analysis.**

13 A. From January 1, 2008, when rates from UE 191 went into effect, through the end  
14 of December 2011 when rates from this case will become effective, customers  
15 will have received \$118 million in lower system NPC as a result of the  
16 Company’s hedging program. It would be unfair to accept the substantial benefits  
17 of the hedging program from 2008 through 2011, and then disallow the costs of it  
18 going forward when nothing material has changed in the Company’s approach or  
19 circumstances.

20 **Q. On a volumetric basis, how much of the natural gas usage in the 2012 GRID**  
21 **NPC study is hedged in the Rebuttal Update?**

22 A. Approximately ■ percent. This is lower than the hedging volume  
23 recommendations of both CUB and ICNU and undermines their claim that the

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<sup>4</sup> PacifiCorp 2011 IRP, Docket LC 52, Appendix G at 165 (Mar. 31, 2011).

1 Company has over hedged with respect to natural gas.

2 **Q. How do customers benefit from the Company's hedge program in years**  
3 **where hedges are unfavorable, such as in the test year?**

4 A. The purpose of the Company's hedge program is to reduce the volatility of NPC.  
5 Absent the Company's hedge program, NPC would be subject to potentially large  
6 swings from year to year depending upon the volatility of the spot market. I  
7 previously demonstrated that the volatility of natural gas and wholesale electric  
8 prices were cut in half as a result of the Company's hedging program.

9 **Retail Load Forecast**

10 **Q. Do parties challenge the Company's retail load forecast used in the Initial**  
11 **Filing?**

12 A. Yes. Staff and ICNU propose adjustments based on challenges to the Company's  
13 load forecast. However, as discussed below, both Staff and ICNU mix and match  
14 different vintages of load forecasts to justify their recommendations, an approach  
15 that fails to recognize that each vintage of load forecast is derived using the best  
16 actual historic and forecast data available at the time the forecast is developed.

17 **Q. What is Staff's argument related to the retail load forecast?**

18 A. Staff argues that the retail load forecast in the 2012 TAM is overstated. Staff  
19 claims that the Company's 2011 IRP projects retail load growth for the 2011-2012  
20 period of 2.3 percent, but the Company used a 7.5 percent increase. However,  
21 Staff erroneously calculates the 7.5 percent increase by comparing the October  
22 2009 forecast for 2011 used in UE 216, the 2011 TAM (October 2009 forecast)  
23 against the November 2010 forecast for 2012 used in this TAM (November 2010

1 forecast). Staff did not quantify its adjustment and indicated it may quantify the  
2 impact at a later time. The Company reserves the right to rebut any quantification  
3 that Staff may propose in the future.

4 **Q. What did ICNU propose with respect to the retail load forecast?**

5 A. ICNU also objects to the Company's retail load forecast as being overstated,  
6 similarly citing the 7.5 percent figure on a total system basis and 7.1 percent for  
7 Oregon. However, ICNU's proposal for addressing this issue is to impute non-  
8 NPC related fixed margin revenue into this proceeding using the same forecast  
9 that it criticizes as overstated. Mr. Griffith explains why the methodology of  
10 ICNU's adjustment is one-sided and inappropriate in an NPC-only proceeding  
11 and is contrary to the TAM Guidelines, to which ICNU stipulated. I address the  
12 reasonableness of the Company's retail load forecast in this case.

13 **Q. Can you clarify the sources of the 2.3 percent increase in retail loads and the  
14 7.5 percent increase in retail loads cited by Staff and ICNU?**

15 A. Yes. The 2.3 percent figure approximates the load growth between 2011 and  
16 2012 that was forecast in the Company's 2011 IRP, which was developed in  
17 October 2010 (October 2010 forecast).

18 As discussed above, the 7.5 percent figure cited by Staff compares the  
19 October 2009 forecast for 2011 against the November 2010 forecast for 2012.

20 **Q. What is the difference between the October 2010 forecast and the November  
21 2010 forecast?**

22 A. After completing the October 2010 forecast, the Company received new and more  
23 accurate information regarding the continuation of a load increase by a large

1 industrial customer in Utah. As noted in the 2011 IRP, this was originally  
2 assumed for 2011 only.<sup>5</sup> The November 2010 forecast extended this load  
3 increase through 2012. This change resulted in an increase in the load forecast of  
4 458 GWh, 52 average megawatts – an increase of 0.8 percent.

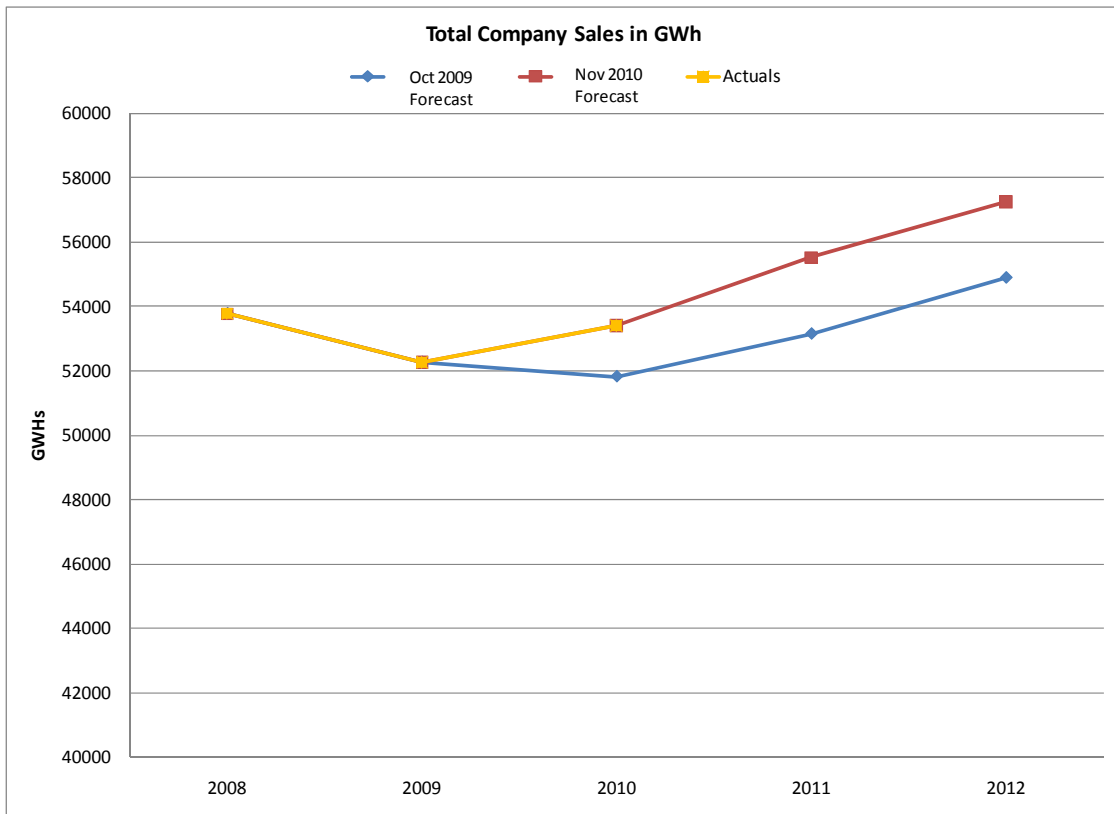
5 **Q. Why is it erroneous to compare growth rates using different vintages of load**  
6 **forecasts?**

7 A. It ignores the fact that new forecasts are based on the best available actual  
8 historical data and forecast data. Importantly, the October 2009 forecast was  
9 developed using actual historical load data through July 2009, while the  
10 November 2010 forecast was developed using actual historical load data through  
11 July 2010. Chart 1 shows the actual historical data on a total company basis,  
12 contrasted with the October 2009 forecast and the November 2010 forecast.  
13 Chart 2 provides this contrast for Oregon.

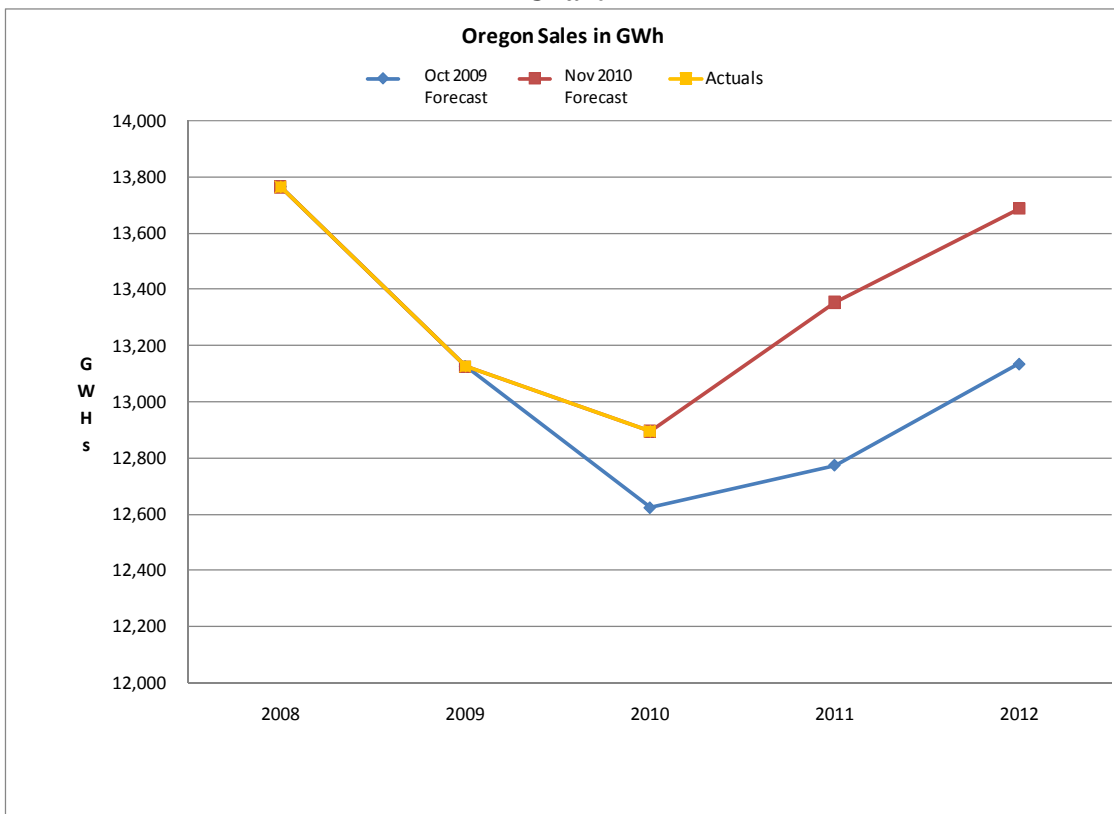
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<sup>5</sup> PacifiCorp 2011 IRP, Docket LC 52, Appendix A at 9 (Mar. 31, 2011).

**Chart 1**



**Chart 2**



1 **Q. Please explain.**

2 A. As noted above, the October 2009 forecast was created in the midst of the  
3 recession, with the knowledge of actual historical loads through July 2009. At  
4 that time, loads had been declining and the Company's view was that it was  
5 unlikely to see much, if any, recovery from the recession during 2010. The  
6 October 2009 forecast therefore incorporated a small decrease between 2009 and  
7 2010 on a system basis, with recovery beginning in 2011 and 2012. For Oregon,  
8 the Company assumed loads would continue to fall in 2010 with recovery  
9 beginning in 2011. As shown above, this forecast was understated for 2010.  
10 Loads in 2010 were several percentage points higher than what the Company had  
11 forecast, both on a system basis and for Oregon.

12 Appropriately, the November 2010 forecast incorporated these higher  
13 actual 2010 loads as a starting point and had the benefit of actual historical load  
14 data through July 2010. Doing otherwise - as Staff and ICNU recommend -  
15 would ignore what has actually occurred. The Company uses the same process  
16 for developing all of its load forecasts, so any differences in forecasts reflect the  
17 information that was available to the Company at the time it developed the  
18 forecast.

19 **Q. Please quantify and explain why 2010 actual sales were higher than the**  
20 **amount forecast in October 2009.**

21 A. On a total Company basis, 2010 actual sales were 1,594 GWh, or three percent  
22 higher than the October 2009 forecast for 2010. Approximately 86 percent (1,371  
23 GWh) of this variance was attributable to economic recovery in the industrial

1 segments, primarily in Utah (517 GWh), Wyoming (387 GWh), and Idaho (398  
2 GWh). A significant portion of the remaining variance was due to higher sales in  
3 the residential class, mainly in Oregon (287 GWh).

4 **Q. What is the retail load growth between 2011 and 2012 in the November 2010  
5 forecast?**

6 A. As shown in the charts above, the Company's filing incorporates a 3.1 percent  
7 growth on a total Company basis, and 2.5 percent growth on an Oregon basis  
8 between 2011 and 2012. For Oregon, this load growth is identical to that  
9 contained in the 2011 IRP forecast. On a total Company basis, the difference is  
10 discussed above.

11 **Q. Do you think that this level of retail load growth is reasonable for 2012?**

12 A. Yes. Based on the information that was available to the Company in November  
13 2010, this level of growth is reasonable based on projected expansion by new and  
14 existing customers in extracting industries, growth in data centers, and economic  
15 development in the Company's service territory as the economy recovers.

16 **Q. In addition to the change in the starting point between the October 2009  
17 forecast and the November 2010 forecast, are there other differences between  
18 the forecast assumptions?**

19 A. Yes. For the commercial class, there was an upward adjustment in the November  
20 2010 forecast to reflect the addition and expansion of large data centers in Utah  
21 and Oregon – certain of which are already on-line and operating. For the  
22 industrial class, additional growth is attributable to recovery by existing large  
23 industrial customers and an updated outlook for new loads by customers in the

1 extractive industry in Utah and Wyoming, as well as increased growth attributable  
2 to a small number of very large industrial customers.

3 **Q. How does the Company forecast usage by its largest customers on the**  
4 **system?**

5 A. The Company conducts regular discussions with its largest customers to seek  
6 information regarding each customer's business trends and expectations over the  
7 coming years. Given the economic uncertainties facing these customers,  
8 expectations on future usage and timing of expansions can change fairly often.

9 **Q. Does the Company have a more recent load forecast than the one included in**  
10 **the Initial Filing?**

11 A. Yes. The Company updated its load forecast in July 2011. As seen in Table 3  
12 below, the July 2011 load forecast is 1,765 GWh lower than the November 2010  
13 forecast. The updated load forecast is based on the revised information received  
14 from industrial and commercial customers and the most recent economic  
15 conditions.

**Table 3**

**Difference Between November 2010 and July 2011 Forecasts**

	<u>Total MWh</u>	<u>OR MWh</u>	<u>WA MWh</u>	<u>CA MWh</u>	<u>UT MWh</u>	<u>ID MWh</u>	<u>WY MWh</u>
July 2011 Forecast for CY 2012	55,481,640	13,435,370	4,107,990	851,260	23,837,760	3,379,350	9,869,910
Nov 2010 Forecast for CY 2012	57,246,690	13,686,920	4,155,920	830,990	24,864,100	3,431,560	10,277,200
July 2011 Forecast minus Nov 2010 Forecast	(1,765,050)	(251,550)	(47,930)	20,270	(1,026,340)	(52,210)	(407,290)
RES - Forecast Difference	(285,957)	(69,800)	(1,392)	10,215	(179,918)	(4,836)	(40,226)
COM - Forecast Difference	(481,259)	(154,602)	(1,537)	4,657	(351,166)	12,560	8,828
IND - Forecast Difference	(939,772)	19,961	(44,830)	6,258	(492,416)	(55,743)	(373,002)

16 **Q. What are the drivers of the reduction in the July 2011 forecast?**

17 A. The following changes from the November 2010 forecast are reflected in the July  
18 2011 forecast.

- 1           ➤ In Utah, the forecast related to a small number of large industrial and  
2           commercial customers has been reduced.
- 3           ➤ In Wyoming, the majority of the reduction is similarly attributed to a  
4           revised forecast for a few industrial customers.
- 5           ➤ In Oregon, the majority of the load reduction is attributable to the timing  
6           of load increases related to data centers.

7           Overall, the reduction to the forecast for the large customers discussed  
8           above represents 77 percent of the reduction for the Company. In addition,  
9           approximately 825 GWh of the industrial load reduction is attributed to certain  
10          industrial customers' plans to displace their retail loads with their on-site  
11          generation due to low wholesale market prices as compared to the retail rate. The  
12          remainder of the difference reflects lower forecasts of residential customer sales,  
13          which is reflective of 2011 results to date. Table 3 details the changes between  
14          the November 2010 forecast for 2012 and the July 2011 forecast for 2012.

15   **Q. Why did the Company not adopt this updated forecast in its Rebuttal Filing?**

16   A. The TAM Guidelines do not provide for updating the load forecast after the  
17   Company's Initial Filing.

18   **Q. Would the Company support reflecting the updated forecast in its Final  
19   Update?**

20   A. Yes, as long as the Commission modifies the TAM Guidelines to require the  
21   Company to update loads in its Rebuttal Filing in all future TAM proceedings. It  
22   would be inappropriate to reflect this lower load forecast but not allow the  
23   Company to update for higher load forecasts in the future.

1 **Q. Has the Company quantified the impact of the July 2011 forecast on the**  
2 **Rebuttal Update?**

3 A. Yes. This updated forecast would reduce the rebuttal update increase by \$4.6  
4 million, resulting in an overall Oregon increase of \$58.8 million.

5 **Q. Do you have any other comments on a change to the TAM Guidelines to**  
6 **accommodate updates to the load forecast after the Initial Filing?**

7 A. Yes. I believe the Commission could consider whether any such update should be  
8 subject to a materiality threshold either on a MWh basis or a total dollar basis.

9 **Market Caps**

10 **Q. Has the Company applied market caps in previous TAM proceedings?**

11 A. Yes. Since implementation of the GRID model, the Company has applied market  
12 caps to wholesale sales modeled in GRID to reflect reasonable limits on market  
13 depth.

14 **Q. Why are market caps necessary?**

15 A. Without market caps, GRID would allow unlimited sales at every market at any  
16 time of the day or night. The historical level of short-term firm (STF)  
17 transactions shows that unlimited sales do not occur in actual operation. To  
18 appropriately reflect this fact in normalized NPC, the Company's market cap  
19 approach first determines the market depth or potential amount of sales  
20 transactions that the Company could enter into. Such a market depth is defined  
21 by the average level of STF sales transactions that the Company was able to enter  
22 into in the 48-month historical base period. The average historical level of STF  
23 transactions is then reduced by the actual STF transactions included in the

1 normalized NPC study in this case, which determines the market caps. That is,  
2 the market caps are defined by the potential level of transactions, net of  
3 transactions that the Company has entered into.

4 **Q. Has this Commission evaluated the market cap issue previously?**

5 A. Although the Company has applied market caps since implementation of the  
6 GRID model, the issue has not been fully litigated before this Commission.  
7 ICNU proposed removing market caps two years ago, in Docket UE 207, and that  
8 case was resolved via settlement. ICNU did not object to market caps in the  
9 following proceeding, Docket UE 216.

10 **Q. What occurred in the time period between UE 207 and UE 216 related to**  
11 **market caps?**

12 A. On February 18, 2010, the Public Service Commission of Utah rejected a proposal  
13 by Mr. Randall Falkenberg, ICNU's witness in UE 207 and UE 216, to eliminate  
14 market caps.<sup>6</sup>

15 **Q. Have any of PacifiCorp's commissions ever approved an adjustment**  
16 **removing market caps?**

17 A. No.

18 **Q. Is Staff objecting to the concept of market caps?**

19 A. No. Staff proposes to restore the market cap methodology previously used in  
20 TAM proceedings. Staff states that this change would reduce system NPC by  
21 \$6.0 million. ICNU proposes eliminating market caps entirely, resulting in a \$5.6  
22 million reduction to system NPC.

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<sup>6</sup> *Re Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah*, Docket 09-035-23, Report and Order on Revenue Requirement, Cost of Service, and Spread of Rates at 27 (Feb. 18, 2010).

1 **Q. Staff argues that the Company has not justified the change in its market cap**  
2 **approach. How do you respond?**

3 A. As in all previous TAM filings, the Company has implemented market caps to  
4 reflect reasonable limits on market depth. The only change is that the Company  
5 refined its measurement of market depth and applied the resulting market caps to  
6 sales in all hours, not just sales in the graveyard hours. This refinement reduced  
7 the overall impact of market caps and lowered NPC, as compared to the market  
8 caps used in prior Oregon cases.

9 **Q. Staff argues that the Company did not demonstrate that the modeling of**  
10 **market caps included in the Initial Filing produces a more reasonable or**  
11 **accurate representation of the actual surplus sales. How would reverting to**  
12 **the prior approach to market caps affect NPC?**

13 A. Applying the same approach to determine market caps used in prior proceedings  
14 would increase system NPC by approximately \$10 million.

15 **Q. Please explain how the Company's approach to market caps in this**  
16 **proceeding reduces NPC as compared to the Company's previous approach,**  
17 **when under this approach the Company limits sales during all hours and the**  
18 **former approach limited sales only during graveyard hours.**

19 A. The data used to determine the market depth in the current proceeding include all  
20 short-term firm transactions in the historical base period, while the data used to  
21 determine the graveyard-hour market caps in the previous cases included only  
22 spot transactions. As a result, compared with the previous market caps, the

1 current market caps allow significantly higher amount of sales transactions during  
2 graveyard hours while slightly limiting sales transaction in all other hours.

3 **Q. ICNU calls into question the logic within the Company's market cap**  
4 **modeling, because there are time periods when GRID modeled no**  
5 **transactions in active trading hubs. Does this indicate a flaw in the**  
6 **Company's modeling?**

7 A. No. There may not be transactions modeled in every hour because the Company  
8 does not have excess generation to sell or the Company's transmission rights do  
9 not allow transfer of energy from one location to another during the relevant time  
10 period. This is irrelevant to the market liquidity issue addressed by market caps.

11 **Q. ICNU argues that PacifiCorp's activity for the six hubs modeled by GRID is**  
12 **a small percentage of the market. What is your response to this argument?**

13 A. I disagree. While it is true that PacifiCorp is only one of many parties active in  
14 these markets, that does not invalidate the evidence of market liquidity upon  
15 which the Company's market caps are based. The historical data that the  
16 Company used to determine the market depth shows that the Company's ability to  
17 sell in these markets is limited, and the Company's market caps appropriately  
18 reflect this fact.

19 **Q. ICNU claims that the level of transactions modeled in GRID does not come**  
20 **close to historical actual levels. How do you respond?**

21 A. ICNU's claim is irrelevant. ICNU makes the same argument that was resolved in  
22 the Company's 2008 TAM filing, UE 191, where Staff proposed an adjustment  
23 for trading margins based on the differences between the GRID generated volume

1 of transactions and the actual volume of transactions. As explained by the  
2 Company in UE 191:

3 This is a characteristic of any deterministic hourly production dispatch  
4 model that balances and optimizes a forecast test year on an hourly basis.  
5 The GRID model produces a lower volume of transactions because it  
6 balances loads and resources on an hourly basis with perfect foresight.  
7 Even with a stochastic model, the volumes may still be lower than actual  
8 results because a model can only capture the variation determined by the  
9 given statistical properties. On an actual basis, system balancing is a long  
10 process that involves numerous updates of load and resource balances due  
11 to changes in load forecasts, the availability of thermal units, hydro  
12 conditions, etc., up to the actual time of delivery. Additionally, products  
13 available in the market are not always a good fit to balance resource  
14 requirements, which also leads to higher actual volumes. As a result,  
15 actual balancing generates higher volumes than GRID or other  
16 deterministic models.<sup>7</sup>

17 **Q. How did the Commission address this issue in UE 191?**

18 A. In its decision, the Commission accepted the Company's explanation, did not  
19 adopt Staff's adjustment, and accepted the Company's calculation of trading  
20 margin for the case. In the current case, the Company again included the short-  
21 term firm (STF) trading margin. As a result, any adjustments to increase the  
22 volume of transactions modeled in GRID, especially through increased market  
23 purchases, would double count the value that has been included through the STF  
24 trading margin.

25 **Q. Has Staff or ICNU provided any new information that would show that the**  
26 **Company would be able to make additional sales in the test period above**  
27 **historical levels in the hours in which market caps are applied?**

28 A. No.

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<sup>7</sup> See Exhibit PPL/204, Widmer/16, lines 9-21.

1 **DC Intertie**

2 **Q. Please explain Staff's and ICNU's proposed adjustment to costs associated**  
3 **with the DC Intertie.**

4 A. Staff argues that the expense associated with the DC Intertie agreement does not  
5 contain corresponding benefits for Oregon customers, is not used and useful and  
6 therefore should be disallowed. ICNU also argues that costs associated with the  
7 DC Intertie should be excluded from NPC on the basis that while the agreement is  
8 used by the Company, the low level of activity does not justify the inclusion of  
9 these costs. The proposed adjustment would result in a \$4.8 million decrease to  
10 total Company NPC.

11 **Q. Please provide some background on the DC Intertie contract.**

12 A. The DC Intertie contract was executed 17 years ago on May 26, 1994, to provide  
13 deliveries of 200 MW of power from Southern California Edison at the Nevada  
14 Oregon Border market hub (NOB) under Amendment 1 to the Winter Power Sales  
15 Agreement (WPSA). The WPSA was executed on December 14, 1993 and  
16 provided up to 422 MW of power to be delivered to the Company's west control  
17 area. At the time the WPSA was executed, the Company had sufficient  
18 transmission rights to import 222 MW of power into the west control area. The  
19 agreement provided that if the Company procured additional transmission rights  
20 by June 1, 1993, then it could import the remaining 200 MW to its system. The  
21 Company secured the remaining 200 MW of transmission rights by acquiring 200  
22 MW of transmission capacity on the DC Intertie. The Company terminated the

1 WPSA effective January 1, 2002, but the DC Intertie contract remained effective  
2 by its terms.

3 **Q. How does the DC Intertie contract benefit the Company's customers today?**

4 A. The agreement takes advantage of the load diversity between summer-peaking  
5 California and the winter-peaking Pacific Northwest. The contract provides a  
6 valuable means of securing capacity and energy from California entities to meet  
7 retail loads. Loads in California are relatively low in the winter when loads in the  
8 Company's west control area and the rest of the Pacific Northwest are at their  
9 highest.

10 **Q. Is there evidence that the Company can reasonably expect to use the DC  
11 Intertie in the rate effective period, even though GRID does not model  
12 transactions at NOB?**

13 A. Yes. The Company made over 200 power purchase transactions at NOB each  
14 year for the past five years. The DC Intertie is used to transfer this power to load.  
15 There is no reason to believe this historical trend will not continue into the future.

16 **Q. Can you quantify the benefit of those transactions as it compares with the  
17 cost of the contract?**

18 A. The cost of the DC Intertie contract is \$1.99 per kilowatt-month, which compares  
19 to over \$8 per kilowatt-month that the Company paid to BPA under the peak  
20 purchase contract.

21 **Q. What would be the result if the DC Intertie were not available to the  
22 Company?**

23 A. If the DC Intertie were not available to the Company, then it would have to be

1 replaced with a new 200 MW resource. Without a new 200 MW resource, the  
2 Company could not serve peak loads. Acquiring a new 200 MW transmission  
3 resource would cost customers significantly more than the cost of the DC Intertie.

4 **Q. If the contract costs more than the dollar benefit of the transactions that use**  
5 **the contract, why is it appropriate to include the full costs of the DC Intertie**  
6 **agreement in rates?**

7 A. In making their proposals, Staff and ICNU focus on energy deliveries under the  
8 contract rather than the capacity deferral and diversity benefits of the contract. It  
9 would be inappropriate to penalize the Company for prudently acquiring  
10 transmission rights 17 years ago by disallowing costs today based on hindsight  
11 and only looking at the energy value of a resource that can facilitate the delivery  
12 of both capacity and energy. By purchasing these transmission rights, the  
13 Company has purchased assurance that it can reliably serve its retail customers  
14 loads. Staff's and ICNU's proposals are based on a limited energy-only view of  
15 this contract, which is similar to arguing that the Company should only be able to  
16 recover insurance premiums when it receives proceeds under an insurance policy.  
17 The costs associated with this contract are modest in light of the benefit to the  
18 Company's overall transmission strategy and hedge against changes in the  
19 market.

20 **Q. How should the Commission judge the prudence of this contract?**

21 A. Prudence should always be judged based on the information that was known at  
22 the time the contract was executed. It would not be reasonable to judge a 17-year

1 old contract based on information that is available today that was not available 17  
2 years ago.

3 **Cal ISO Fees**

4 **Q. Please describe Staff's and ICNU's adjustments to Cal ISO fees.**

5 A. Staff and ICNU recommend removal of the Cal ISO wheeling expenses and fees.  
6 They claim that the Cal ISO system capability is not modeled in GRID and there  
7 is no offsetting benefit reflected in the filing. The proposed adjustment would  
8 result in a \$4.3 million reduction to system NPC.

9 **Q. Is Staff's and ICNU's claim that the Cal ISO system capability is not  
10 modeled in GRID a valid concern?**

11 A. No. In actual operations, the Company does not use the Cal ISO system  
12 capability. The Cal ISO fees are incurred when the Company transacts with the  
13 Cal ISO at market hubs that are modeled in GRID, such as the California Oregon  
14 Border, Four Corners, Mona and Palo Verde. The benefit of wholesale sales and  
15 purchases at these locations are already reflected in GRID.

16 **Q. Will the Company enter into transactions with the Cal ISO in the rate  
17 effective period?**

18 A. Yes. Staff stated in response to the Company Data Request 1.5 that Staff does not  
19 dispute whether the Company engages in Cal ISO transactions, and ICNU stated  
20 in response to the Company Data Request 1.11 that ICNU does not dispute this  
21 fact either. The responses to these data requests are included as Exhibit PPL/109.

1 **Q. Is ICNU correct that the Company would not have entered into these**  
2 **transactions unless there was a clear profit margin at the time of the**  
3 **transaction?**

4 A. No. The Company enters into transactions with the Cal ISO to serve load, not to  
5 earn a margin. The Company will enter into transactions with the Cal ISO if the  
6 Cal ISO is the Company's most economic option to serve load at that time. As a  
7 result, eliminating the Cal ISO as a counterparty will require the Company to  
8 enter into higher-priced transactions to serve load, thereby increasing NPC.

9 **Q. If it is clear that the Company will engage in transactions with the Cal ISO in**  
10 **the future, what is the basis for the parties' adjustment?**

11 A. Staff and ICNU claim that the benefits associated with the Cal ISO transactions  
12 are not reflected in NPC.

13 **Q. Are they correct?**

14 A. No. As previously described, all of the benefits of transacting with the Cal ISO  
15 are modeled in GRID. In general, when the Company's flexibility is removed or  
16 restricted, the costs of serving load increase. Removing the Cal ISO as a  
17 counterparty would limit the Company's ability to fully utilize the market and  
18 cause NPC to increase. The retooling of GRID that would be required to remove  
19 Cal ISO as a counterparty would result in increased costs elsewhere, because the  
20 Company would need to find a way to replace the transactions it makes with the  
21 Cal ISO. The premise of the parties' adjustment that there would be a net benefit  
22 that would offset Cal ISO expenses or even reduce NPC is wrong. The benefit of  
23 doing business with the Cal ISO is to avoid doing something more expensive in

1 order to serve load. If the Commission were to disallow Cal ISO fees as a  
2 legitimate expense, the Company would be forced to find alternatives to doing  
3 business with the Cal ISO.

4 **Q. How are Cal ISO transactions modeled in the filing?**

5 A. Cal ISO transactions are reflected in the system balancing sales and purchases  
6 where no counterparties are explicitly identified. This is because the Company  
7 transacts with the Cal ISO in the real-time and day-ahead markets since those are  
8 the only markets in which the Cal ISO transacts. System balancing sales and  
9 purchases capture all transactions necessary to balance the system. Historic  
10 trends and the Company's actual verifiable experience demonstrate that the  
11 Company regularly transacts with the Cal ISO in order to serve load in a reliable  
12 and cost-effective manner. Cal ISO expenses are an ongoing and regular expense  
13 incurred by the Company in the normal course of business and should be  
14 recovered in NPC.

#### 15 **Wind Integration**

#### 16 **CUB's Proposal to Use the BPA Wind Integration**

17 **Q. What is the first wind integration adjustment you address?**

18 A. I address CUB's proposal to use BPA's wind integration charge as a proxy for the  
19 Company's wind integration costs. CUB claims that because stakeholders who  
20 participated in the Company's public process to analyze the 2010 Wind  
21 Integration Study (Wind Study) were not satisfied with the outcome, the  
22 Company should use BPA's wind integration charge of \$5.83 per MWh to  
23 calculate NPC in this case. This compares to the Company's wind integration

1 charge of approximately \$6.32 per MWh in the Company's Initial Filing. CUB  
2 did not quantify this adjustment.

3 **Q. Please provide some background on the Wind Study.**

4 A. The Commission required the Company in Order No. 10-066 to complete a Wind  
5 Study by August 2, 2010. The Company initiated its public participation process  
6 with a public stakeholder meeting on February 26, 2010 to discuss the general  
7 framework and methodology for the Wind Study. The Company provided its  
8 draft 2010 Wind Study methodology paper on April 16, 2010, a revised draft  
9 methodology study on April 28, 2010, and a third draft methodology study on  
10 May 19, 2010 based on comments received from stakeholders and the Company's  
11 technical advisor The Brattle Group. The Company filed a motion with the  
12 Oregon Commission to extend the Wind Study due date to September 1, 2010 to  
13 accommodate more stakeholder study review time, and allot the Company  
14 additional time to investigate and validate modeling results.

15 **Q. Did the Oregon Commission's imposed timeframe play a factor in your  
16 decision to hire the technical advisor The Brattle Group?**

17 A. Yes. Because of the limited time the Company had to produce an updated Wind  
18 Study, the Company selected a technical advisor rather than forming a technical  
19 advisory committee. Use of a technical advisory committee would necessarily add  
20 a significant amount of time in order to accommodate the numerous scheduling  
21 issues that would arise when attempting to bring together multiple parties from  
22 different time zones and working constraints. The Company believes that its  
23 technical advisor, The Brattle Group, provided a thorough and objective

1 independent review of the Wind Study. In the action plan for the 2011 IRP, the  
2 Company indicated it will form a technical review committee as part of its next  
3 wind integration study.

4 **Q. Does the Company believe that its Wind Study results are accurate and**  
5 **complete?**

6 A. Yes. The Wind Study verifiably depicts the Company's costs of integrating wind  
7 into its system.

8 **Q. How do you respond to CUB's point that some stakeholders were not**  
9 **satisfied with the Wind Study?**

10 A. The Company carefully considered all recommendations made by stakeholders  
11 who participated in the Wind Study process and as necessary consulted with  
12 The Brattle Group to evaluate whether any given recommendation might  
13 improve the study design and overall validity of the study results. There were  
14 numerous instances where the Company agreed with the recommendations  
15 submitted by stakeholders and incorporated them into the Wind Study.

16 It is neither feasible nor practical to expect that the Company would have  
17 incorporated all of the stakeholder recommendations as the process moved  
18 forward. All of the stakeholders did not agree with all aspects of the Wind Study,  
19 making it impossible to incorporate the views and opinions of all of those who  
20 participated in the process. While there were instances where the Company did  
21 not agree with the recommendations made by stakeholders, at no time did the  
22 Company intentionally suppress the views and criticisms of any of the

1 stakeholders with the intentions of driving the Wind Study to a predetermined  
2 outcome.

3 Finally, I note that the only entities referenced by CUB—the Renewable  
4 Northwest Project and Mr. Randall Falkenberg—are not participating in this case.  
5 The Company therefore has no opportunity to conduct discovery on or respond to  
6 their arguments, so it would be improper to disallow costs based on CUB’s  
7 representations of their concerns.

8 **Q. Are BPA’s wind integration costs directly comparable to the Company’s**  
9 **wind integration costs included in NPC?**

10 A. No. BPA imposes its charge for intra-hour integration of wind integration (*i.e.*,  
11 the integration costs between the scheduled generation to be delivered to BPA and  
12 the actual generation by the wind projects). The charge does not include the  
13 Company’s inter-hour wind integration costs, which are approximately \$0.70 per  
14 MWh. When BPA’s intra-hour charge is combined with the Company’s inter-  
15 hour charge, it results in a total charge of \$6.53 per MWh, which is higher than  
16 the Company’s proposed combined charge for intra- and inter-hour integration of  
17 \$6.32 per MWh.

18 **Q. Is the Company aware of any other available wind integration studies from**  
19 **an Oregon electric utility?**

20 A. Yes. Portland General Electric (PGE) recently filed the preliminary results of its  
21 wind integration study. According to its results, PGE estimates wind integration  
22 costs of approximately \$14.46 per MWh to integrate 850 MW of wind on its

1 system. In comparison, the Company's wind integration costs are less than half  
2 this amount and are for a much higher level of wind generation.

3 **Q. Does CUB present any evidence showing that the Company's wind**  
4 **integration charge is inaccurate?**

5 A. No. CUB's only argument is that some stakeholders were not satisfied with the  
6 study.

7 **Wind Study Must-Run Assumptions**

8 **Q. Do Staff and ICNU agree with the Company's must-run settings as applied**  
9 **to Gadsby units 4-6 and Currant Creek in GRID?**

10 A. No. Staff argues that the Company has provided no evidence that the Gadsby  
11 units 4-6 and Currant Creek units currently operate on a must-run basis to provide  
12 regulating reserves for wind or that they will actually operate in this manner in  
13 2012. ICNU contests the must-run settings for Gadsby units 4-6, but does not  
14 contest the must-run setting for Currant Creek. Staff's adjustment would result in  
15 a \$1.1 million decrease to total-Company NPC, while ICNU's adjustment would  
16 result in a \$2.9 million decrease to total-Company NPC.

17 **Q. Is applying the must-run setting to these units appropriate?**

18 A. Yes. While it is true that a must-run setting forces Gadsby units 4-6 and Currant  
19 Creek to operate in all hours, the must-run setting also ensures that these gas units  
20 are committed and able to carry reserves replicating the Company's real time  
21 operations. When the must-run setting is applied, units are committed and  
22 required to run at minimum levels, leaving GRID with the option to use the

1 remaining capacity (the capacity differential between the minimum and the  
2 maximum rating) for reserves.

3 **Q. Staff and ICNU argue that the Company does not operate the Gadsby units  
4 4-6 as must-run facilities. How do you respond?**

5 A. While the start-up data indicates that Gadsby units 4-6 tend to cycle and that one  
6 of the Currant Creek CTs cycles, albeit less frequently than the Gadsby units, the  
7 start-up data in and of itself does not show how generation from these units with  
8 must-run settings in GRID over the test period compare to historical generation  
9 data. Relative to generation in 2009, the period of historical data reviewed when  
10 the use of must-run settings were first implemented in the Wind Study, the  
11 average capacity factors for Gadsby units 4-6 and Currant Creek in GRID  
12 compare well to the average capacity factors derived from historical operational  
13 data. Over the test period in the Company's filed NPC, with must-run settings  
14 turned on, GRID yields a 32 percent average capacity factor for Gadsby units 4-6  
15 and a 53 percent capacity factor for Currant Creek. In 2009, Gadsby units 4-6  
16 were operated at a 33 percent capacity factor and Currant Creek was operated at a  
17 65 percent capacity factor. As such, the must-run settings applied in GRID result  
18 in generation that is consistent with actual operational practice.

19 **Liquidated Damages**

20 **Q. Please explain CUB's proposed adjustment related to liquidated damages.**

21 A. CUB recommends an adjustment to incorporate a four-year rolling average of the  
22 Company's settlements for liquidated damages related to forced outages at  
23 generation plants.

1 **Q. How do you respond?**

2 A. The Company is not philosophically opposed to the new methodology proposed  
3 by CUB to reflect a four-year rolling average for liquidated damages. However,  
4 the Company does not agree that this adjustment should be introduced in a stand-  
5 alone TAM filing. First, the adjustment is not consistent with the TAM  
6 Guidelines. Second, liquidated damage payments are incorporated in the  
7 Company's revenue requirement in general rate case proceedings if the Company  
8 receives the payment during the base year. Liquidated damages are typically not  
9 recorded in the Federal Energy Regulatory Commission (FERC) accounts that are  
10 listed in the TAM Guidelines. In order to avoid double counting with payments  
11 already reflected in base rates, CUB should recommend this new methodology in  
12 a TAM filed concurrently with a general rate case.

13 **Affiliate Mine Incentives**

14 **Q. Please explain Staff's proposed adjustment related to employee costs at the**  
15 **Bridger Plant.**

16 A. Staff proposes to remove from NPC 50 percent of incentives, 50 percent of  
17 employee meals and gifts, and 100 percent of donations associated with the  
18 Bridger Coal Company and Deer Creek Mine. Staff argues that this proposal is  
19 consistent with Commission policy on these adjustments. Staff's adjustment  
20 reduces system NPC by \$1.8 million.

21 **Q. Do you agree that these adjustments are consistent with Commission policy?**

22 A. No. Staff has not presented any justification or basis for the Commission to find  
23 the identified costs to be imprudent.

1 **Q. Do the costs referenced by Staff provide benefits to customers?**

2 A. Yes. As Staff concedes, affiliate coal costs are lower than market costs,  
3 undermining Staff's proposal to disallow costs associated with operating the  
4 mines.

5 **NAES Adjustments**

6 **BPA Transmission Credit**

7 **Q. What has NAES proposed with respect to the BPA Transmission Credit?**

8 A. NAES proposes that the Schedule 294 and 295 transition adjustment calculations  
9 be modified to include a credit for the resale of BPA transmission in the same  
10 amount as the 25 MW load decrement used in computing the transmission  
11 adjustment. Alternatively, if this proposal is not adopted, NAES recommends that  
12 the BPA credits adopted in the Docket UE 216 stipulation continue to be applied  
13 in the 2012 TAM.

14 **Q. What had the Commission previously found with respect to the BPA  
15 transmission credit?**

16 A. As Mr. Higgins discussed in his testimony, the Commission rejected proposals to  
17 recognize a BPA transmission credit in Order No. 04-516 in Docket UM 1081.

18 **Q. Why does NAES raise this issue in this case?**

19 A. NAES argues that circumstances are different today than when the Commission  
20 issued its order in UM 1081. NAES states that in 2004 the Company was  
21 contractually precluded from reselling its BPA wheeling rights, but that is no  
22 longer the case.

1 **Q. Do you agree that this changed circumstance supports including a BPA**  
2 **transmission credit in the calculation of transition adjustments?**

3 A. No. The Commission’s decision in UM 1081 was not based solely on the fact that  
4 the Company was precluded from reselling its BPA transmission rights. The  
5 Company also argued that even if it “could avoid a purchase as a result of direct  
6 access load loss, it could neither avoid purchasing transmission nor resell the  
7 freed up transmission to capture any value.”<sup>8</sup>

8 **Q. Is it still the case that the Company does not obtain value from freed up**  
9 **transmission services?**

10 A. Yes. Depending on the location of the lost load and the existing transmission  
11 arrangements with BPA and the Company’s transmission function, the value of  
12 freed up transmission with BPA is minimal. In addition, the Company may need  
13 to acquire additional transmission in order to deliver the freed up generation to  
14 market in order to realize the transition credits determined for the lost load.

15 **Q. Has the Company provided information to NAES on its actual experience**  
16 **with the transmission that might be freed up as a result of direct access load**  
17 **loss?**

18 A. Yes. The Company has exchanged emails with Mr. Greg Bass of NAES and  
19 provided a response to an NAES data request on the subject. This information  
20 supports the Company’s position that other customers would have to subsidize the  
21 imputed value of freed-up transmission in the transition adjustment. While the  
22 transmission services that the Company acquires from BPA to serve some of the  
23 sites in Oregon may be impacted by customers electing direct access, among

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<sup>8</sup> See Order No. 04-516 at 6.

1 those sites, there was limited Point to Point (PTP) access that the Company could  
2 release on a seasonal basis. In addition, the sites to which BPA PTP transmission  
3 connects may not directly reach the load pockets of the direct access customers.

4 **Q. What is your proposal with respect to the BPA Transmission Credit?**

5 A. I recommend that the Commission reject NAES' proposal to include a BPA  
6 Transmission Credit in the calculation of the transition adjustment.

7 **Line Losses**

8 **Q. What is NAES' proposal regarding the line loss percentages used to calculate**  
9 **the Schedule 294 and 295 transition adjustments?**

10 A. NAES proposes that the line losses charged to Oregon's electric service suppliers  
11 (ESS) in the Company's Open Access Transmission Tariff (OATT) be the same  
12 as those used in the calculation of the transition adjustment. NAES argues that  
13 having different loss factors used in the state direct access arena and the federal  
14 OATT arena creates disadvantages in the pricing of direct access service for  
15 certain delivery voltages.

16 **Q. Is NAES participating in the Company's transmission rate case before the**  
17 **FERC?**

18 A. Yes. The Company filed its transmission rate case with FERC on May 26, 2011.  
19 NAES filed a protest in that proceeding on June 16, 2011, and the Company  
20 responded to that protest on July 1, 2011.

21 **Q. What are NAES' central arguments with respect to the Company's proposed**  
22 **revisions to the OATT?**

23 A. First, NAES argues that the Company's proposed Schedule 10 in the OATT

1 should differentiate between distribution delivery at primary and secondary  
2 voltage. Second, NAES argues that there is a discrepancy between the line losses  
3 charged to an ESS through the OATT and those used in Oregon rates.

4 **Q. With respect to NAES' first argument, why does the Company's OATT**  
5 **Schedule 10 not differentiate between distribution delivery at primary and**  
6 **secondary voltage?**

7 A. Schedule 10 does not differentiate between distribution delivery at primary and  
8 secondary voltage because the Company does not provide secondary delivery  
9 service under its wholesale transmission rates, so it is not appropriate to include a  
10 secondary voltage loss factor in OATT Schedule 10. Secondary delivery voltage  
11 is [related](#) to retail service, which is not jurisdictional transmission service  
12 provided under the Company's OATT.

13 **Q. With respect to NAES' second argument, why are the line losses in the**  
14 **OATT different from those used in Schedules 220, 294, and 295?**

15 A. This issue is largely a matter of the timing of the Company's OATT filing and the  
16 timing of this filing. The current OATT loss factors set forth in OATT Schedule  
17 10 are based on a 1995 loss study which was the most current study available at  
18 the time Schedule 10 was last updated. Oregon Schedules 220, 294 and 295  
19 reflect more recent loss studies from 2007 reflecting a state-specific loss analysis  
20 including lower voltage levels associated with service at the state retail level. As  
21 part of its transmission rate case filing at the FERC, the Company included a  
22 proposed updated Schedule 10 and loss study with respect to its transmission  
23 losses over facilities at 46 kV.

1 **Q. What is the Company's position on NAES' proposal?**

2 A. While loss factors in state rate cases have been updated with the most recent  
3 factors from the 2007 loss study, the OATT Schedule 10 loss factor has not been  
4 updated with those most recent loss factor results. Until the loss factors in the  
5 OATT are approved by FERC in the Company's rate case, the Company does not  
6 have the authority to change them. The Company proposes that the current  
7 OATT-approved loss factors be reflected in Schedule 220, as described by Mr.  
8 Griffith, and be used to set the transition adjustments in Schedules 294 and 295  
9 until FERC approves an OATT with updated loss factors. In this approach an  
10 ESS is held harmless by differences between line loss factors in the OATT and in  
11 the retail tariff because what they are credited for under the retail tariff will equal  
12 what they are charged for by the transmission provider.

13 **Q. Does this conclude your rebuttal testimony?**

14 A. Yes, it does.