

REDACTED
Docket No. 20000-____-ER-11
Witness: Gregory N. Duvall

BEFORE THE WYOMING PUBLIC SERVICE
COMMISSION

ROCKY MOUNTAIN POWER

REDACTED Direct Testimony of Gregory N. Duvall

December 2011

1 **Q. Please state your name, business address and present position with**
2 **PacifiCorp dba Rocky Mountain Power Company (“the Company”).**

3 A. My name is Gregory N. Duvall. My business address is 825 NE Multnomah, Suite
4 600, Portland, Oregon 97232. My present position is Director, Net Power Costs.

5 **Qualifications**

6 **Q. Briefly describe your education and business experience.**

7 A. I received a degree in Mathematics from University of Washington in 1976 and a
8 Masters of Business Administration from University of Portland in 1979. I was
9 first employed by PacifiCorp in 1976 and have held various positions in resource
10 and transmission planning, regulation, resource acquisitions and trading. From
11 1997 through 2000 I lived in Australia where I managed the Energy Trading
12 Department for Powercor, a PacifiCorp subsidiary at that time. After returning to
13 Portland, I was involved in direct access issues in Oregon and was responsible for
14 directing the analytical effort for the Multi-State Process (“MSP”). Currently, I
15 direct the work of the load forecasting group, the net power cost group, and the
16 renewable compliance area.

17 **Purpose of Testimony**

18 **Q. What is the purpose of your testimony in this proceeding?**

19 A. I present the Company’s proposed net power costs (“NPC”) for the 12-month
20 period ending March 31, 2013. Specifically, my testimony:

- 21 • Describes the primary drivers behind the increase in NPC as well as factors
22 that mitigate the increase;
- 23 • Describes changes that the Company has made to the NPC study since the

1 Company's 2010 general rate case, Docket No. 20000-384-ER-10 ("2010
2 general rate case");

- 3 • Provides background and support for the hedging and wind integration costs
4 included in the Company's NPC; and
- 5 • Proposes a process to update NPC during this and future general rate case
6 proceedings to improve the accuracy of the base NPC rate while
7 accommodating the needs of other parties to review and validate the NPC
8 updates.

9 **Summary of Net Power Costs in the Current Filing**

10 **Q. What are the proposed system-wide NPC for the 12-month period ending**
11 **March 2013?**

12 A. The proposed NPC for the 12-months ending March 31, 2013, are approximately
13 \$1.496 billion on a total Company basis, and \$248.5 million on a Wyoming
14 allocated basis. The proposed NPC are approximately \$193 million higher than
15 the \$1.303 billion currently in rates on a total Company basis, and \$20.9 million¹
16 on a Wyoming allocated basis.

17 **Q. Please generally describe the drivers of the Company's NPC in this filing.**

18 A. Table 1 below illustrates the change in total Company NPC by category from the
19 NPC baseline in the 2010 GRC Stipulation, which included a \$48 million
20 settlement adjustment. This adjustment is not reflected in this filing, although as
21 described below, the Company has incorporated a number of adjustments

¹ Wyoming's share of the \$193 million increase is just over \$30 million, but is offset in part by a decrease in the allocation percentages applied to all NPC of approximately \$10 million, resulting in a net increase to NPC for Wyoming customers of \$20.9 million.

1 proposed in the 2010 general rate case.²

TABLE 1
Net Power Cost Reconciliation (\$millions)

2010 General Rate Case	1,303
Increase/(Decrease) to NPC:	
Wholesale Sales	198
Purchased Power	(61)
Coal Generation	74
Gas Generation	(13)
Wheeling Hydro and Other	(5)
2011 General Rate Case	1,496

2 The increase in NPC from the 2010 GRC baseline is driven largely by an increase
3 in coal fuel burn expense of \$74 million, and a decrease in wholesale sales
4 revenues of \$198 million. These increases in costs are partially offset by a
5 decrease in purchased power of \$61 million and a decrease in wheeling expense
6 of \$5 million. In addition, the Company is forecasting its retail load to be 886
7 gigawatt-hours (“GWh”) less than its load forecast in the 2010 GRC.³

8 **Q. On an energy basis, how has the operation of the Company’s system changed**
9 **since the 2010 general rate case?**

10 A. Since the 2010 GRC, approximately 1,000 GWh of long-term purchased power
11 contracts have expired leaving the Company with less power to serve load and
12 sell in the wholesale markets. The Company is forecasting the volume of

² Removal of the settlement adjustment increases system purchased power costs by \$15 million, increases system natural gas expense by \$9 million, and reduces system wholesale sales revenues by \$24 million. Since the settlement adjustment is built into the \$1.303 billion system NPC in rates, it is not added separately in Table 1.

³ The Company continues to forecast increases in loads over time, but at a lower rate of growth than was expected in the forecast used in the 2010 general rate case.

1 wholesale sales to be lower by 304 GWh. In addition, short-term increases in
2 wholesale market prices for electricity have made it more economic to generate
3 additional energy from thermal plants and purchase less. Overall, the system
4 shows an increase in coal generation of 739 GWh and an increase in natural gas
5 generation of 753 GWh, offset by a concomitant reduction in purchased power in
6 addition to the reduction caused by the loss of the long-term contracts.

7 **Discussion of Major Cost Drivers in NPC**

8 **Q. Please discuss the reduction in wholesale sales revenues in NPC in the test**
9 **year.**

10 A. As shown in Table 1, on a total Company basis, overall sales revenue has declined
11 by \$198 million from \$723⁴ million in the 2010 general rate case to \$526 million
12 in the current test period. The primary driver of this change is the decline in
13 forward market prices for electricity over the past several years and the impact of
14 this decline on wholesale sales revenue. The reduction in wholesale sales revenue
15 in the test period is reflective of the decrease in average sales price of about
16 \$13/megawatt-hour (“MWh”), from \$37/MWh for the current test period versus
17 the 2010 GRC average sales price of \$50/MWh. This price reduction applies to
18 about 14.0 million MWh of wholesale sales and accounts for \$182 million of the
19 \$198 million reduction in overall sales revenue decline. The remaining \$16
20 million reduction in overall sales revenue can be attributed to the 304 GWh
21 reduction in wholesale sales volume noted above.

⁴ This comparison reflects a restatement of the NPC from the 2010 general rate case to separate electric swaps between wholesale sales revenues and wholesale purchased power expense. Previously, the net of all electric swaps were reported in purchased power expense.

1 **Q. Does the decline in wholesale sales revenue contribute to the net natural gas**
2 **and power hedging costs in this case?**

3 A. Yes. The Company's forecast hedging costs in this case are \$119 million total
4 Company. This consists of natural gas hedging costs of \$144 million and power
5 hedging benefits of \$24 million. Even though the Company's natural gas hedging
6 costs are lower in this case than in the 2010 general rate case and the Company
7 has hedged only [REDACTED] of its open position in GRID for the test period, this
8 case presents a net hedging loss primarily because of reduced power hedge
9 revenues.

10 **Q. Please explain the increase in coal expenses in the current proceeding.**

11 A. Approximately \$74 million of the system NPC increase in the current proceeding
12 is attributable to coal costs. Coal expenses have increased due to both price and
13 volume, with approximately \$58 million of the total cost increase due to
14 commodity price increases and the remaining \$16 million due to increases in
15 generation. Price increases are reflected in both the costs of third-party coal
16 supply and transportation agreements, and cost increases at the Company's
17 captive mines. Coal generation has increased because of the completion of turbine
18 upgrades and because market prices are higher in the test period versus the 2010
19 general rate case resulting in less economic displacement of the coal units. Details
20 on coal costs are provided in the direct testimony of Company witness Ms. Cindy
21 A. Crane.

1 **Q. Please explain the decrease in purchased power expense in the test period as**
2 **compared to the 2010 general rate case.**

3 A. The \$61 million reduction in system purchased power expense from \$775 million
4 to \$714 million is primarily driven by a 2.7 million MWh reduction in the volume
5 of purchases, from 17.9 million MWh to 15.3 million MWh. The reductions in
6 volume are caused by expiring contracts and increased generation from the
7 Company's thermal fleet as compared to the generation levels included in the
8 2010 general rate case. This reduction in purchase volume results in a reduction to
9 purchased power expense of about \$115 million. These savings are partially offset
10 by higher purchased power expenses of about \$54 million reflecting higher unit
11 prices. Overall, purchased power prices are higher for the 12-months ending
12 March 31, 2013 by approximately \$3.50/MWh when compared to the purchased
13 power prices for the 12-months ending December 31, 2011, used in the 2010
14 general rate case. While prices remain relatively low in the current filing, they
15 are higher than the 2010 general rate case. This increase in market prices for
16 purchases appears to cause the increased generation of the Company's coal and
17 natural gas units, which are now more cost effective to produce power rather than
18 purchase power from the market.

19 **Q. What are the major changes to the Company's long-term power contracts?**

20 A. The current filing reflects a full year impact of the contracts that expired during
21 calendar year 2011. These include the following:

- 22 • On June 30, 2011, the exchange contract between the Company and the Alcoa
23 Power Generating Inc. ("APGI") for approximately 100 MW of capacity from

1 the Rocky Reach project expired. Under this contract, the Company received
2 energy during peak periods and returned energy during off-peak periods.

3 • On August 31, 2011, the contract between the Company and the Bonneville
4 Power Administration (“BPA”) for 575 MW of capacity expired. Under this
5 contract, the Company received energy during peak periods and returns
6 energy during off-peak periods. In addition, power received under this
7 contract was delivered directly to a variety of the Company’s load pockets in
8 the western area at the Company’s discretion.

9 • On September 30, 2011, the contract between the Company and the Grant
10 Public Utility District (“Grant PUD”) for displacement generation expired,
11 which was priced at BPA’s Priority Firm Power (“PF”) rate.

12 • On October 31, 2011, the contract between the Company and the Chelan
13 Public Utility District (“Chelan PUD”) for generation from the Rocky Reach
14 project expired. Power purchased by the Company under this contract was
15 priced at the embedded cost of the project.

16 NPC increased when these contracts expired because the prices of these contracts
17 were more favorable as compared to the current market prices.

18 **Q. What is the impact of lower retail load?**

19 A. The 886 GWh reduction in retail load lowers system NPC by approximately \$25.9
20 million, based on a comparison of the load forecast used in the 2010 GRC, versus
21 the load forecast used in this filing. The load forecast in this case reflects the fact
22 that the actual retail sales in 2011 came in below the levels forecast in the 2010
23 general rate case. In addition, a number of industrial customers with on-site

1 generation are expected to serve a portion of their own requirements with their
2 own generation and several data centers have indicated that their expansion plans
3 will not occur as soon as they previously indicated. While the Company continues
4 to forecast load growth, it is expected to be slower than the growth forecast in
5 October 2010. For further details on the load forecast, please refer to the
6 testimony of Company witness Dr. Peter C. Eelkema.

7 **Q. Why has wheeling expense decreased?**

8 A. Wheeling expense has decreased primarily as a result of the expiration of the
9 Centralia point-to-point wheeling contract on June 30, 2012.

10 **Changes to the NPC Study since the 2010 general rate case**

11 **Q. What changes has the Company made to the NPC study since the 2010**
12 **general rate case?**

13 A. In response to issues raised by parties in the Company's 2010 GRC, the Company
14 has refined the following inputs to Generation and Regulation Initiative Decision
15 model ("GRID"):

- 16 • Lewis River – The Company now inputs normalized generation into the GRID
17 model on a weekly basis to better reflect the Company's operation of its hydro
18 facilities for generating and providing reserves. This addresses the Wyoming
19 Industrial Energy Consumer's ("WIEC") proposed adjustment E-24 from the
20 2010 general rate case.
- 21 • Bear River – The normalized capacity and generation now includes the impact
22 of flood control years and reflects the Company's more recent operation of the
23 Cutler and Oneida plants and their ability to provide an increased level of

1 reserves through motoring of the units. This addresses WIEC's proposed
2 adjustment A-2 from the 2010 general rate case.

3 • California Independent System Operator ("Cal ISO") – Transactions with the
4 Cal ISO are explicitly modeled in the GRID based on historical levels. This
5 addresses WIEC's proposed adjustment A-7 from the 2010 general rate case.

6 • DC Intertie – The Company's rights to use the DC Intertie has been added to
7 the GRID topology. This allows GRID to purchase power at the Nevada
8 Oregon Border ("NOB") market hub to serve load. This addresses WIEC's
9 proposed adjustment F-25 from the 2010 general rate case.

10 • Gadsby Must-Run – The Gadsby peaking units, units 4, 5 and 6, are no longer
11 modeled as must-run units in evening hours. This addresses one aspect of
12 WIEC's proposed adjustment B-14 from the 2010 general rate case.

13 • Non-Owned Wind – Company witness Mr. Brian S. Dickman proposes a
14 mechanism in his testimony to track revenues from non-owned wind for later
15 return to customers. This addresses one of the Office of Consumer Advocates'
16 ("OCA") proposed adjustments in the 2010 general rate case.

17 • Morgan Stanley Call Options – These contracts have expired and have been
18 removed from GRID. This addresses WIEC's proposed adjustment A-11 from
19 the 2010 general rate case.

20 • Centralia Point-to-Point Wheeling – This contract expires on June 30, 2012,
21 and has been removed beyond that time. This addresses WIEC's proposed
22 adjustment F-26 from the 2010 general rate case.

23 • Hydro Outage Rates – The Company has adopted WIEC's recommendation

1 from the 2010 general rate case. This addresses WIEC's proposed adjustment
2 A-3 from the 2010 general rate case.

3 • Bridger Coal Adjustment – The Company has systematically removed all
4 fines and citations. This addresses WIEC's proposed adjustment A-8 from the
5 2010 general rate case.

6 • BPA Transmission Rate Increase – The rates for the Bonneville Power
7 Authority have been set and are no longer an estimate for the test period in
8 this case. This addresses WIEC's proposed adjustment F-27 from the 2010
9 general rate case.

10 • Station Service Corrections – The Company has adopted WIEC's
11 recommendation from the 2010 general rate case. This addresses WIEC's
12 proposed adjustment G-31 from the 2010 general rate case.

13 Hedging Analysis

14 **Q. What information are you presenting on hedging?**

15 A. The direct testimony of Mr. Stefan A. Bird provides background on the
16 Company's hedging program, updates the hedging gain/loss analysis previously
17 filed in Wyoming, explains the net hedging costs in this filing, and proposes that
18 Wyoming stakeholders engage in collaborative discussions with the Company on
19 prospective changes to the Company's hedging policy. In support of Mr. Bird's
20 testimony, I present analysis demonstrating that over the course of the last several
21 years, the Company's hedging program has substantially reduced the volatility of
22 NPC.

1 **Q. How does the Company’s hedging strategy benefit Wyoming customers?**
2 A. The Company’s hedging strategy mitigates the volatility of NPC and protects
3 against large swings in NPC as a result of unforeseeable changes in wholesale
4 market prices for electricity and natural gas. Using an assessment methodology
5 developed by the Staff of the Oregon Public Utility Commission, for the period
6 2005-2010, the Company’s hedging of natural gas reduced the volatility of gas
7 prices by 50 percent and reduced the volatility of wholesale power prices by 52
8 percent as shown in Tables 2 and 3.⁵

Table 2 – 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%
Overall	\$5.12	0.17	\$5.68	0.35	-11%	50%

Table 3 - 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%
Overall	\$57	0.16	\$49	0.34	13%	52%

⁵ 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 **Q. Has the Company developed additional analysis on the issue of NPC**
2 **volatility and hedging?**

3 A. Yes. The Company's 2011 Integrated Resource Plan ("IRP") addresses this issue
4 and demonstrates that the Company's portfolio approach to hedging, which is
5 both comprehensive and integrated from a power/natural gas standpoint, reduces
6 the volatility of NPC.

7 **Wind Integration Costs**

8 **Q. What are the Company's wind integration costs included in NPC?**

9 A. The costs of integrating wind generation in the Company's balancing authority
10 areas included in NPC are approximately \$4.03/ MWh.

11 **Q. Does the Company continue to base its wind integration costs on the results**
12 **of the 2010 Wind Integration Study ("Wind Study") filed with this**
13 **Commission in both the 2010 general rate case and the 2011 Integrated**
14 **Resource Plan dockets?**

15 A. Yes. The Company continues to believe that the level of reserves required to
16 integrate wind generation net of system load, as identified in the Wind Study, is
17 appropriate. The 533 MW of required regulating and following reserves, based on
18 the results of the Wind Study, is also supported by the actual reserves carried on
19 the Company's system during 2010, which showed that the Company carried 540
20 MW of regulating and following reserves on average throughout the year.

21 **Q. Does the 540 average MW of actual reserves carried on the Company's**
22 **system in 2010 measure the same components as the 533 average MW**
23 **calculated by the Wind Study?**

1 A. Yes. Using 2010 actual measured reserve data, the Company determined that 540
2 average MW of regulating and following reserves were available to the system for
3 the purpose of balancing intra-hour fluctuations.⁶

4 **Q. What is regulating and following reserves, and why does the Company**
5 **include regulating and following reserves when forecasting NPC in GRID?**

6 A. In its role as balancing authority, the Company must match system resources to
7 actual load and variable generation fluctuations on a moment-to-moment basis to
8 maintain system reliability and system frequency. The Company accomplishes
9 this by setting aside capacity in reserve that can be called upon in response to
10 fluctuations in load and generation. Fluctuations in generation from variable
11 energy resources such as wind introduce incremental variability and uncertainty,
12 thereby increasing the amount of reserves that the Company must set aside. The
13 regulating and following reserves in GRID represents the amount needed to
14 maintain reliability given variability and uncertainty from both load fluctuations
15 and wind fluctuations. This reserve capacity cannot be used to serve load or be
16 used to make wholesale sales and represents a portion of the cost of reliability in
17 the NPC forecast.⁷ The regulating and following reserves are in addition to the
18 operating reserves the Company is required to carry to manage forced outages of
19 its generating fleet.

⁶ The Company inadvertently understated its historical reserve analysis in my rebuttal testimony in the 2010 general rate case, combining the following and regulating reserve requirements using the root sum square for a total regulating margin of 447 average megawatts. Subsequently, the Company realized it was not appropriate to do a root sum square of the two types of reserves in calculating actual reserves, due to the fact that they are calculated dependently in the Company's actual records and not independently as was done in the Wind Study. The historical reserve analysis in this case uses the corrected calculation.

⁷ In addition to regulating margin, NPC forecasts reflect reliability costs from the requirement to carry contingency reserves as defined in the WECC Standard BAL-STD-002-0. The same standard defines a requirement for regulation reserves or load following reserves as "sufficient regulating margin to allow the balancing authority to meet NERC's control performance criteria."

1 **Q. Can GRID model moment to moment fluctuations in load and variable**
2 **generation, or the operating reserve requirements they impose?**

3 A. No. The GRID model is an hourly model and therefore cannot reflect the
4 unexpected and unforeseen changes that occur on the Company's system on a
5 moment to moment basis during the course of each hour. Due to this fact, it is
6 important to include these regulating and following reserves in GRID so that the
7 model more closely reflects the actual costs and operating parameters on the
8 system.

9 **Q. Has the Company made any changes to the reserve requirements since the**
10 **2010 general rate case?**

11 A. Yes. First, the Company corrected the level of wind capacity that was included in
12 the Wind Study. The Wind Study reported additional reserve requirements for
13 integrating wind at 1,372 MW and 1,833 MW penetration levels. The Company
14 has since corrected these figures to 1,586 MW and 2,046 MW, respectively. That
15 is, the 533 MW of reserve requirement was based on integrating 2,046 MW of
16 wind capacity. Second, the Company increased the reserve requirement from 533
17 MW to 553 MW, or an increase of approximately 20 MW to account for the
18 increase in online wind capacity of approximately 188 MW compared to the
19 amount used in the Wind Study. The additional wind capacity is included in
20 GRID, so it is appropriate to increase the regulating and following reserve
21 requirements accordingly.

1 **Q. Has the Company included the costs associated with integrating the non-**
2 **owned wind generation in the Company's balancing authority areas?**

3 A. Yes. As explained in the 2010 general rate case, the Company is required by
4 federal law to provide wind integration services to its wholesale customers on a
5 non-discriminatory basis. Therefore, the Company continues to believe it is
6 appropriate to reflect these costs in rates as prudent and necessary costs associated
7 with operating its system.

8 **Q. Has the Company filed its transmission rate case with FERC, and included**
9 **charges for ancillary services for non-owned wind facilities?**

10 A. Yes. The Company filed its transmission rate case on May 26, 2011, under docket
11 number ER11-3643. In that case, the Company proposed a new Schedule 3A that
12 will apply to all transmission customers delivering energy from generators in
13 PacifiCorp's balancing authority areas to other balancing authority areas. The
14 transmission rate case is pending with FERC.

15 **Q. Does the Company propose to include these incremental revenues resulting**
16 **from the FERC transmission rate case in Wyoming rates once they are**
17 **known and measurable?**

18 A. Yes. As more fully explained in the direct testimony of Mr. Dickman, since the
19 exact timing and amount of any increase are unknown at this time, the Company
20 proposes to defer any ancillary service revenues resulting from the FERC
21 transmission rate case for the period that new FERC rates are in effect through the
22 end of the test period March 31, 2013. Wyoming's allocated share of these
23 deferred revenues that are incremental to revenues included in the Company's

1 filing may then be passed through to Wyoming customers as directed by the
2 Commission.

3 **Updates to NPC**

4 **Q. Does the Company propose to update NPC during the course of this**
5 **proceeding and in general rate cases in the future?**

6 A. Yes. The Commission authorized the Company to establish an Energy Cost
7 Adjustment Mechanism (“ECAM”) in which the base NPC will be set in general
8 rate cases. In order to achieve the most accurate forecast of base NPC, and thus
9 minimize the deferred NPC, the Company proposes to update the following
10 limited categories of NPC:

- 11 • The official forward price curve for electricity and natural gas;
- 12 • Coal costs;
- 13 • Wholesale sales and purchase contracts for electricity and natural gas, for both
14 physical and financial products;
- 15 • Transmission contracts to wheel generation to load centers; and
- 16 • Transportation contracts to deliver natural gas to generation facilities.

17 **Q. When does the Company propose to make these updates during this**
18 **proceeding and future general rate case proceedings?**

19 A. The Company proposes to update NPC for the limited categories before other
20 parties’ filing their direct testimony. In this proceeding, the Company proposes to
21 file the update on April 13, 2012. Prior to the update filing, the Company
22 proposes to periodically provide new information in those categories that will be
23 reflected in the update filing, such as on a monthly basis or when a significant

1 amount of information has been accumulated. The Company believes that this
2 will allow adequate time for parties to review the information prior to filing their
3 direct testimony.

4 **Q. Why is it reasonable to update NPC during the course of a general rate case
5 proceeding?**

6 A. The Company's load and resource balance for any given period change with time,
7 as do market prices and contracts. As a result, the operation of the Company's
8 system continues to change during the course of the NPC proceeding. Applying
9 the most current NPC inputs increases the overall accuracy of the NPC baseline in
10 rates. In Docket No. 20000-368-EA-10 ("2010 ECAM"), the Commission
11 emphasized the importance of an accurate NPC forecast for base rates, finding
12 that the ECAM should be structured to, among other things, provide the Company
13 an incentive "to encourage the accuracy of modeling supporting the forecasts."
14 The Company's proposal to update NPC will ensure that the NPC forecast for the
15 rate effective period is as accurate as possible, consistent with this policy.

16 **Q. Will such updates unreasonably impact other parties' abilities to review the
17 Company's NPC?**

18 A. No, the Company believes the additional burden is reasonable given the limited
19 scope of the update and the provision of new information in a timely fashion.
20 These updates are transparent, apply equally whether they increase or decrease
21 NPC, can be easily verified and are straightforward to model in GRID. In addition
22 to providing contracts and notifications to parties prior to its rebuttal filing, the
23 Company will provide work papers to support these updates. For these reasons,

1 evaluating the Company's update at the rebuttal stage as proposed by the
2 Company should not unduly burden other parties.

3 **Q. Do other commissions allow the Company to update its NPC inputs,**
4 **including the forward price curve after the initial filing?**

5 A. Yes. This has become the regular practice in Oregon and Washington with the
6 goal of improving the accuracy of the NPC in rates. For example, the Oregon
7 Commission authorizes the Company to update its forward price curve and new
8 information on contracts for electricity and natural gas after it has entered its final
9 order, but prior to the time rates go into effect. In fact, in his ECAM testimony,
10 WIEC witness Mr. Randall J. Falkenberg commented favorably on the accuracy
11 of the Oregon power cost filing, due to the fact that the Oregon Commission
12 allows for multiple updates throughout the proceeding. In the Company's last
13 general rate case in Washington, the Washington Utilities and Transportation
14 Commission directed the Company to update the forward price curve in its
15 compliance filing to reflect the most recent market prices for gas and electricity
16 prior to setting base NPC.

17 **Determination of NPC and Model Inputs and Outputs**

18 **Q. Please explain NPC.**

19 A. NPC are defined as the sum of fuel expenses, wholesale purchase power expenses
20 and wheeling expenses, less wholesale sales revenue.

21 **Q. Please explain how the Company calculates NPC.**

22 A. NPC are calculated for a future test period based on projected data using GRID.
23 GRID is a production cost model that simulates the operation of the Company's

1 power system on an hourly basis.

2 **Q. Is the Company's general approach to the calculation of NPC using the**
3 **GRID model the same in this case as in previous cases?**

4 A. Yes. The Company has used the GRID model to determine NPC in its Wyoming
5 filings for several years.

6 **Q. Is the Company using the same version of the GRID model as used in its 2010**
7 **general rate case?**

8 A. Yes.

9 **Q. What inputs were updated for this filing?**

10 A. All inputs have been updated since the 2010 GRC, including system load,
11 wholesale sales and purchase contracts for electricity, natural gas and wheeling,
12 market prices for electricity and natural gas, fuel expenses, and the characteristics
13 and availability of the Company's generation facilities. As noted previously,
14 many issues raised by intervenors in the 2010 GRC have also been addressed in
15 this filing.

16 **Q. Has the Company changed its GRID model topology?**

17 A. Yes. There are two main changes to the GRID model topology. The first change
18 better reflects the wheeling contracts with Idaho Power Company and the impact
19 of the Energy Gateway project, specifically the Populus to Terminal line. The
20 second change better reflects the operational constraints of the Company's
21 wheeling contracts with the BPA after the expiration of the BPA Peaking
22 contract.

1 **Q. What reports does the GRID model produce?**

2 A. The major output from the GRID model is the NPC report. This is attached to my
3 testimony as Exhibit RMP___(GND-1). Additional data with more detailed
4 analyses are also available in hourly, daily, monthly and annual formats by heavy-
5 load hours and light-load hours.

6 **Q. In paragraph 6 of the 2011 PCAM settlement agreement, the Company**
7 **agreed that it would not change the Company-owned wind projects'**
8 **normalized annual generation during the five-year term of the ECAM,**
9 **except for the possible instance where a mechanical (other than ordinary**
10 **turbine outages) or Force Majeure event may affect the capacity and or the**
11 **capacity factor. Does the Company's NPC study reflect this commitment?**

12 A. Yes. The Company encountered a Force Majeure event at Foote Creek I with the
13 collapse of one turbine. The output of this project was scaled down to reflect this
14 Force Majeure event. No other changes were made to the annual generation
15 Company-owned wind facilities.

16 **Q. Does this conclude your direct testimony?**

17 A. Yes.