

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

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”) based on actual data
20 for the 12-month period ending December 2010 with known and measurable
21 changes through December 2011 in support of the Company’s 2011 test period in
22 this case. Specifically, my testimony:

- 23
- Addresses the specific adjustments related to the GRID model described in the

1 section for net power costs of the Commission Order No. 32196 (“2010 Rate
2 Case Order”) in the Company’s 2010 general rate case, Case No. PAC-E-10-
3 07 (“2010 GRC”).

- 4 • Describes the major cost drivers in the 2011 NPC.
- 5 • Presents the Company’s updated wind integration charges based on the
6 verifiable 2010 Wind Integration Study and explains how they are
7 incorporated in the current filing.

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

9 **Q. What are the normalized net power costs for the test period?**

10 A. The normalized NPC for the 12 months ending December 2011 are approximately
11 \$82.8 million on an Idaho allocated basis, or \$1.312 billion system-wide as
12 presented in Exhibit No. 35. The allocation of total Company NPC to Idaho is
13 presented in Exhibit No. 2 in Company witness Mr. Steven R. McDougal’s direct
14 testimony.

15 **Q. How do proposed NPC compare with the NPC that the Commission** 16 **authorized in the Company’s last general rate case, Case No. PAC-E-10-07?** 17 **(the “2010 General Rate Case”)**

18 A. The NPC authorized in the 2010 General Rate Case were \$1.025 billion on a total
19 Company basis or \$66.0 million on an Idaho allocated basis. On a total Company
20 basis, NPC have increased approximately \$287 million from \$1.025 billion to
21 \$1.312 billion. Idaho’s allocated portion of NPC in the current filing is
22 approximately \$16.8 million higher than the NPC currently included in
23 customers’ rates.

1 **Q. Why have NPC increased?**

2 A. To understand why NPC have increased, I present Table A which illustrates the
3 changes in NPC by category:

Table A
Comparison of Idaho 2011 GRC to Idaho 2010 GRC

Category	Change in Costs Favorable	Change in Costs Unfavorable	Change in MWh
Total Special Sales For Resale		(\$347,220,266)	(4,518,537)
Total Purchased Power & Net Interchange		(\$1,826,473)	3,536,077
Total Coal Fuel Burn Expense		(\$12,281,065)	(3,434,792)
Total Gas Fuel Burn Expense	\$85,607,243		(3,750,177)
Wheeling and Other		(\$11,309,616)	(151,448)
Net system Load			718,186
Total Net Power Costs	\$85,607,243	(\$372,637,421)	0

4 As shown in Table A, the increase in NPC is driven largely by the unfavorable
5 change in revenues from sales for resale (wholesale sales), which is partially
6 offset by a favorable change in natural gas fuel burn expense. The decline in
7 wholesale sales revenues is primarily driven by a drop in market prices which are
8 30 percent lower in the current filing as compared to the 2010 GRC filing. In
9 addition, the Company had significantly less volume of wholesale sales and
10 thermal generation because: 1) low market prices make it more economic at times
11 to displace thermal units with purchases from the market; and 2) more capacity
12 from the thermal units is needed to provide reserves due to the 2,183 MW of wind
13 generation in the Company's Balancing Authority Areas ("BAA") at the end of
14 2010.

15 **Q. Have you included the results of its most recent wind integration study into**
16 **the current filing?**

17 A. Yes. In response to Order No. 32196 from the 2010 GRC, I am sponsoring a wind

1 integration study (“Wind Study”) that verifiably depicts the Company’s wind
2 integration costs. The inclusion of these costs is consistent with Order No. 32196,
3 where the Commission stated: “We are not happy with this end result, because we
4 believe these integration costs belong in base rates.”¹ The Wind Study results
5 showing a regulation reserve requirement² of 533 megawatts (“MW”) are further
6 supported by the fact that the Company carried 629 MW of regulation reserves in
7 2010. Lastly, instead of the dollar per megawatt-hour (“MWh”) adder used in the
8 last case, the Company improved its modeling and reflected the Wind Study’s 533
9 MW regulation reserve requirement within the Generation and Regulation
10 Initiative Decision (“GRID”) model, resulting in an accurate depiction of how the
11 Company’s system incurs costs associated with wind generation resources in the
12 test period.

13 **Q. Please briefly explain the change in GRID associated with the Company’s**
14 **2010 Wind Study.**

15 A. The results of the Wind Study showed that on average the Company would need
16 to carry reserves for the intra-hour variations of load and wind of 533 MW. This
17 is an increase of approximately 267 MW over the 2010 GRC filing, which
18 included regulation reserves to address load variability, but did not include any
19 additional regulation reserves to manage the 2,183 MW of wind in the Company’s
20 BAAs, and instead addressed this reserve cost as an incremental line item charge
21 of \$6.50/MWh. The \$6.50/MWh charge for reserves in the 2010 GRC filing has
22 been eliminated and replaced in the GRID model by the total wind net load

¹Case No. PAC-E-10-07, Order No. 32196 page 30, Issued February 28, 2011.

²“Regulation requirement” or “regulation reserves” consist of reserves available in 10 minutes (referred to as regulating reserves) and reserves available in 60 minutes (referred to as load following reserves).

1 reserve requirement determined in the Wind Study. The GRID model then
2 calculates the costs associated with the regulation reserves by backing off
3 generation to supply those reserves that would otherwise be used to serve load or
4 generate margins to reduce net power costs. These additional reserve
5 requirements are one contributor to the reduction in generation seen in Table A of
6 the Company's coal and natural gas-fired resources. I will discuss this in more
7 detail later in my testimony.

8 **Q. How will the normalized NPC approved by the Commission in this**
9 **proceeding be used for setting retail rates in Idaho?**

10 A. The approved normalized NPC from this proceeding will establish the level of
11 NPC included in base rates and will set the base NPC for purposes of the Energy
12 Cost Adjustment Mechanism ("ECAM") and will be trued-up to actual NPC
13 consistent with the mechanics of the ECAM.

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

15 **Q. Please explain NPC.**

16 A. NPC are defined by the NPC report included as Exhibit No. 35 and include the
17 sum of fuel related expenses, wholesale purchase power expenses and wheeling
18 expenses, less wholesale sales revenue.

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

20 A. NPC are calculated using the GRID model. GRID is a production cost model that
21 simulates the operation of the Company's power system on an hourly basis.

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

3 A. Yes. The Company used the GRID model in its last rate filing in Idaho.

4 **Q. Is the Company using the same version of the GRID model as used in the**
5 **2010 General Rate Case?**

6 A. Yes.

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

8 A. The system load, wholesale sales and purchase contracts for electricity, natural
9 gas and wheeling, market prices for electricity and natural gas, fuel expenses,
10 characteristics of the Company's generation facilities, normalized planned
11 outages and normalized forced outages of the Company's generation resources are
12 updated for this filing. I address some of these components later in my testimony
13 along with changes to include transactions with the Cal ISO and changes in the
14 modeling of market caps.

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

16 A. The major output from the GRID model is the NPC report. This is attached to my
17 testimony as Exhibit No. 35. Additional data with more detailed analyses are also
18 available in hourly, daily, monthly and annual formats by heavy-load hours and
19 light-load hours.

20 **Q. Has the Company changed its modeling of normalized hydro generation?**

21 A. No.

1 **Adjustments Identified in the Commission Order**

2 **Q. What adjustments did the Commission direct the Company to make in**
3 **Order No. 32196?**

4 A. In Order No. 32196, the Commission directed the Company to make adjustments
5 for Normalization of Call Option Contracts, Wind Integration Costs, and Cal ISO
6 Wheeling & Service Fees. The Normalization of Call Option Contracts the
7 contracts that the Company has with Black Hills Power (“Black Hills”) and the
8 Sacramento Municipal Utility District (“SMUD”).

9 **Q. How does the Company model the normalization of call option contracts in**
10 **the current filing?**

11 A. For the contracts with Black Hills and SMUD, the Company modeled the energy
12 delivery using a three-year historic average, as directed by the Commission in
13 Order No. 32196.

14 **Q. Please discuss the Commission’s decision on wind integration costs?**

15 A. In its order, the Commission denied the inclusion of wind integration costs in the
16 Company’s base net power costs, stating that:

17 [n]o party to this case denies that wind integration costs are real
18 costs; the consensus, however is that they cannot be readily
19 forecast with accuracy, calculated or verified... The Company, we
20 find, has not presented the Commission with a verifiable study
21 depicting its wind integration costs.³

22 **Q. Has the Company updated its modeling approach in GRID to more**
23 **accurately calculate wind integration costs?**

24 A. Yes. As part of its 2011 Integrated Resource Plan, the Company conducted an

³Case No. PAC-E-10-07, Order No. 32196, page 30 issued February 28, 2011.

1 extensive Wind Study that assessed the impact of integrating wind generation into
2 its resource portfolio. The Wind Study is provided as Exhibit No. 36. In the
3 current filing, the Company has reflected the results of the Wind Study, which I
4 will discuss in more detail later in my testimony.

5 **Q. Has the Company included wind integration costs for wholesale transmission**
6 **customers in its current NPC filing?**

7 A. Yes. The Company is required to integrate wholesale customers in a non-
8 discriminatory manner under federal law pursuant to the Company's Open Access
9 Transmission Tariff ("OATT"). The OATT does not allow the Company to
10 charge for these integration costs separately from other charges under the OATT.
11 However, customers are benefited by the Company being a balancing area
12 authority and receiving wheeling revenues from wholesale customers which are
13 applied as a credit against the cost of providing retail service. On or before June 1,
14 2011, the Company will file a wholesale rate case with the Federal Energy
15 Regulatory Commission ("FERC") to update its wholesale transmission rates. As
16 part of that filing, the Company is requesting a new Schedule 3A which, if
17 approved by FERC, will allow the Company to charge generators that do not have
18 load in the BAA for regulation reserves.

19 **Q. How does the Company respond to the Commission's decision on Cal ISO**
20 **fees in the 2010 Rate Case Order?**

21 A. The Commission's decision was made based on the fact that the Company's net
22 power cost calculations in that case did not include transactions explicitly with the
23 Cal ISO as the counterparty. The Commission indicated that transaction data

1 should have been provided if the Company intended for the Cal ISO fees to be a
2 continuing expense. To address this concern, the Company added Cal ISO
3 transactions to the GRID model. The transactions with the Cal ISO are a
4 necessary part of the Company's activities to serve its load obligation and balance
5 its system. Because of its diversity and liquidity, the Cal ISO is an important
6 counterparty for the Company when approaching time of delivery, which is also a
7 fact that Monsanto agreed to in Mr. Mark T. Widmer's testimony: "Historical
8 records reveal that most of the transactions with the Cal ISO as a counter party are
9 incurred shortly before or on the actual day of delivery."⁴ As a result, the
10 Company has modeled expected sales and purchase transactions with the Cal ISO
11 based on historical averages.

12 **Q. Please explain how such transactions are modeled in the Company's current**
13 **filing?**

14 A. Based on data in the same four-year historical period used to determine the
15 market caps, the Company calculated the average amount of energy sold to and
16 purchased from the Cal ISO on a monthly basis and by heavy load hour ("HLH")
17 and light load hour ("LLH"). The executed short term firm transactions that the
18 Company included in the filing are through the end of March 2011. For the
19 remainder of the test period, the Company modeled expected transactions with
20 Cal ISO at three major points of delivery based on historical information: Four
21 Corners ("4C"), California Oregon Border ("COB") and Mona. Because these are
22 expected transactions, similar to "System Balancing" sales and purchases, they

⁴See Docket No. ID PAC-E-10-07, Confidential Corrected Direct Testimony of Mark Widmer, Page 24, Lines 1-2.

1 are grouped with the system balancing sales and purchases as modeled by GRID
2 at corresponding points of delivery. Together with these transactions, the
3 Company included the expected Cal ISO wheeling fees and service fees.

4 **Major Cost Drivers in the 2011 NPC**

5 **Q. Please identify the major cost drivers in the 2011 NPC.**

6 A. As identified in my summary, the primary cost driver is the reduction in
7 wholesale sales brought about by lower market prices and reduced thermal
8 generation offset in part by a reduction in natural gas fuel expense. Other drivers
9 include the following:

- 10 • An increase in retail sales;
- 11 • Expiration of a number of long-term wholesale power contracts;
- 12 • Increased coal expense; and
- 13 • An increase in the wholesale power and wind integration rates of the
14 Bonneville Power Administration (“BPA”).

15 Finally, in this section I describe the treatment of the Monsanto contract and
16 changes to modeling of market caps.

17 **Q. Please describe the impact of lower wholesale sales volumes and revenues.**

18 A. Volumes of wholesale sales are down by 4.5 million MWhs as shown in Table 1.
19 This reduced volume of wholesale sales is estimated to increase NPC by \$157
20 million. In addition, wholesale electricity market prices are approximately 30
21 percent lower than those included in the 2010 GRC. Even with no change in
22 volume, wholesale sales revenues would be approximately \$190 million lower

1 due to changes in market prices alone.⁵ The reduction in wholesale sales revenues
2 is offset in part by lower natural gas fuel expenses in the current filing of \$86
3 million. Although purchased power prices are also lower, the overall purchased
4 power expense increased by just under \$2 million due to increased volumes of 3.5
5 million MWhs.

6 **Q. What are the major drivers to the reduced volume of wholesale sales?**

7 A. The primary drivers to reduced wholesale sales volume include reduced thermal
8 generation, increased retail loads, and expiration of several long-term wholesale
9 power contracts including purchase and sale exchanges.

10 **Q. Why is thermal generation lower in the current filing as compared to the**
11 **2010 GRC?**

12 A. As shown in Table A, coal fired generation is lower by 3.8 million MWh and
13 natural gas fired generation is lower by 3.5 million MWh. The primary drivers for
14 this reduction are economic displacement and increased reserves modeled in
15 GRID. Economic displacement of thermal units is a consequence of market price
16 reductions that result in a higher frequency of times when thermal generation is
17 uneconomic to operate. Thermal generation is also lower due to the explicit
18 modeling of regulation reserves in GRID, which requires thermal generation to be
19 backed down to carry the necessary regulation reserves required to integrate load
20 and wind generation variability and maintain reliability.

⁵19.2 million megawatt-hours (“MWh”) at prices that are approximately \$9.9/MWh lower.

1 **Q. Please explain how the drop in wholesale electricity market prices and**
2 **natural gas prices affects how the GRID model holds reserves.**

3 A. The change in the wholesale electricity market prices is greater than the drop in
4 natural gas prices which reduces the amount of time the Company's natural gas-
5 fired resources are economically dispatched. When the GRID model determines
6 that it is uneconomic to dispatch a gas-fired resource and that resource was
7 carrying reserves, then that reserve carrying requirement is shifted to other
8 resources including coal. For example, if Lake Side I is not dispatched because it
9 is uneconomic to do so, it is no longer available to hold reserves, therefore the
10 model will hold reserves on the next available resource, which would show as a
11 decline in generation of that resource due to the fact that it is now holding
12 reserves rather than being able to generate and serve load or sell into the
13 wholesale market. This decline in generation associated with reserve holding is
14 apparent in the reductions in Table A of the Company's coal and natural gas-fired
15 resources.

16 **Q. Do the NPC in this filing reflect increases in coal costs since the 2010 GRC?**

17 A. Yes. As shown in Table A, NPC are higher by approximately \$12 million even
18 though generation from coal units has declined by 3.4 million MWhs.
19 Notwithstanding this decline in the volume of coal generation, increased costs of
20 third-party coal supply and transportation agreements, and cost increases at the
21 Company's captive mines are driving these costs. Details on coal costs are
22 provided in the direct testimony of Company witness Ms. Cindy A. Crane.

1 **Q. What are the major changes to power contracts in the test period?**

2 A. The contracts that have expired or will expire, change or are new in the test period
3 include:

4 • On June 30, 2011, the exchange contract between the Company and the Alcoa
5 Power Generating Inc. (“APGI”) for approximately 100 MW of capacity from
6 the Rocky Reach project expires. Under this contract, the Company receives
7 energy during peak periods and returns energy during off-peak periods.

8 • On October 31, 2011, the contract between the Company and the Chelan
9 Public Utility District (“Chelan PUD”) for generation from the Rocky Reach
10 project expires. Power purchased by the Company under this contract is priced
11 at the embedded cost of the project.

12 • On August 31, 2011, the contract between the Company and the Bonneville
13 Power Administration (“BPA”) for 575 MW of capacity expires. Under this
14 contract, the Company receives energy during peak periods and returns energy
15 during off-peak periods. In addition, power received under this contract is
16 delivered directly to a variety of the Company’s load pockets in the western
17 area at the Company’s discretion.

18 • On September 30, 2011, the contract between the Company and the Grant
19 Public Utility District (“Grant PUD”) for displacement generation expires,
20 which is priced at BPA’s Priority Firm Power (“PF”) rate.

21 • On January 1, 2011, the amount of sales to the Public Service Company of
22 Colorado (“PSCol”) reduces per the contract terms, which is a legacy sales
23 contract at relatively high contract prices.

1 **Q. Does the filing reflect an increase in load that impacts NPC?**

2 A. Yes. This filing reflects an increase of approximately 1.2 percent in the total
3 Company system load compared to loads reflected in the 2010 GRC. All else held
4 constant, increased load increases NPC, which in this case increased NPC by
5 approximately \$15 million. The system load in this filing is the actual load in
6 2010, adjusted for temperature.

7 **Q. What assumptions did the Company make in regard to the power rates and
8 transmission rates proposed in the current rate cases of the BPA?**

9 A. The BPA rate cases will determine the new rates for the fiscal period beginning in
10 October 2011. Given the current proposals made by BPA, the Company assumes
11 that the wheeling expenses of the Company's transmission contracts with BPA
12 would not change in the new BPA rate effective period that begins in October
13 2011. In the current filing, the Company has incorporated the proposed wind
14 integration charge at \$1.32/kilowatt(kW)-month beginning in October 2011,
15 which is a change from the current \$1.29/kW-month. The Company has also
16 incorporated the impact of BPA's proposed charges for reserves and power.

17 **Q. Does the Company expect to update the expenses related to all contracts with
18 BPA?**

19 A. Yes. The Company will update its NPC on rebuttal with the final decision of the
20 BPA rate cases currently expected in July 2011, or when better information
21 becomes available.

1 **Q. How is the price of the contract with Monsanto for interruptible products**
2 **reflected in the test period?**

3 A. Given the interim agreement with Monsanto, the previous contract price at
4 \$[REDACTED]/kW-month is effective through April 28, 2011. Beginning on April 29,
5 2011, the contract price is equivalent to \$[REDACTED] million per year as authorized by
6 the Commission or \$[REDACTED]/kW-month for 162 MW for a term ending May 31,
7 2011. We expect that should the Company and Monsanto need additional time to
8 complete a long term agreement, then this interim agreement will be extended.

9 **Q. Please describe the Company's change to the modeling of market caps?**

10 A. To address the issues around the Company's assumption about market caps
11 during the graveyard hours, the Company reviewed its overall approach to market
12 caps and developed a more comprehensive approach to modeling market depth.
13 Instead of specifying market depth for graveyard hours only, the Company now
14 proposes to specify market depth during all hours, segregated by HLH and LLH
15 periods. The Company believes that a market may be liquid, but this liquidity
16 does not translate into unlimited sales at any time of day or night. Due to load
17 requirements and transmission constraints in the region and static assumptions
18 about market prices in GRID, among other things, the Company may not be able
19 to sell all its economic generation to the markets. The market depths for wholesale
20 sales in GRID are now determined based on the historical short-term firm
21 transactions during the same 48-month period on which availability of the thermal
22 generation is based. The depths are then reduced by the quantity of short-term

1 firm transactions that the Company has included in the normalized NPC study for
2 the test period in all sales markets.

3 **Wind Integration Costs**

4 **Q. Please discuss the Company's approach to calculating wind integration**
5 **costs?**

6 A. The remainder of my testimony discusses the Company's treatment of wind
7 integration costs. As part of the 2011 IRP, the Company performed an extensive
8 Wind Study on the impact of integrating wind generation into its resource
9 portfolio. The Wind Study was completed after reviewing the issues and concerns
10 raised by various parties in Idaho and other jurisdictions, such as whether the
11 wind integration costs should be studied independent of load, the amount of
12 additional reserves needed to integrate the wind generation and what resources
13 should be utilized to serve the additional reserve requirements.

14 **Q. Please describe the Company's Wind Study.**

15 A. The purpose of the Wind Study is twofold. First, the Wind Study quantifies how
16 wind generation affects the amount of additional reserves needed to maintain
17 reliability. Second, the Wind Study determines the costs of integrating wind
18 generation by measuring how system costs change with changes in operating
19 reserve demand, and by measuring how system costs are affected by daily system
20 balancing practices.

21 **Q. What are the additional reserve requirements?**

22 A. The Wind Study identified additional regulation reserve requirements in two
23 categories: regulating services that deal with load and wind variability in 10-

1 minute intervals, and load following services that deal with load and wind
2 variability over hourly time intervals. Both services respond to the up and down
3 variations of wind generation. That is, the additional reserve requirements to
4 integrate wind generation into the Company's resource portfolio consist of
5 regulating up, regulating down, load following up and load following down. The
6 Wind Study performed analyses of additional reserve requirements for load only
7 (excluding wind generation) and for wind net of load (including wind generation),
8 based on historical 10-minute data for the Company's system.

9 **Q. In order to provide for this additional regulating and load following**
10 **requirement, what changes in operations has the Company had to make?**

11 A. Given the size of the wind portfolio, and the possibility of rapid variations in wind
12 generation, the Company has had to commit its gas-fired generation units to be
13 able to quickly respond to the magnitude of changes. At times, this "must-run"
14 operation requires gas-fired generation units to run when it would otherwise be
15 uneconomic to do so, thereby adding to the wind integration costs.

16 **Q. How did the Company incorporate the results from the Wind Study?**

17 A. The amount of the total regulation reserve requirements to meet system variability
18 is 337 average MW and 196 average MW for the east and west sides of the
19 Company's system, respectively, for a total of 533 MW system-wide. The 533
20 MW is an increase of approximately 267 MW from the 2010 GRC, which only
21 captured regulation reserve requirement for load variability, but did not include
22 any incremental reserves for wind variability.

1 **Q. Did the Company also change how it modeled its thermal resources in order**
2 **to accommodate the additional reserve requirements in GRID?**

3 A. Yes. In order to accommodate the increase in regulation reserve requirements as
4 identified in the Wind Study, the Company modeled the Currant Creek unit, and
5 Gadsby units 4, 5 and 6 as must-run units that are not subject to the logic of being
6 committed to run only when economic. Modeling these resources as must-run is
7 consistent with the Wind Study, in which the Company concluded that it was
8 appropriate in order for the model to be “reasonably aligned with actual
9 operational characteristics of the east-side gas plants...”⁶

10 **Q. Does the Company believe that by reflecting the additional reserve**
11 **requirements, instead of reflecting a dollar per MWh charge, it more**
12 **accurately reflects the costs of integrating wind into its system?**

13 A. Yes. Allowing the GRID model to optimize the system, taking into consideration
14 the additional reserves required to integrate the level of wind that is included in
15 the GRID model, more accurately reflects the real-time operation of the system.

16 **Q. Does this change in how the Company has modeled its wind integration costs**
17 **address the Idaho Commission’s concern that it is over recovering its costs**
18 **associated with wind integration?**

19 A. Yes. The Wind Study is a verifiable study of the Company’s costs associated with
20 integrating wind generation into its systems. It clearly demonstrates the additional
21 requirements for regulation reserves, and the requirement to have sufficient must-
22 run thermal resources online to provide a quick response to the significant

⁶See Exhibit No. 36, the Wind Study, Page 25.

1 variations in wind generation. The level of reserves needed to meet variations in
2 load and wind identified in the Wind Study are supported by actual reserves held
3 by the Company for this purpose in 2010. There is no reason to believe that the
4 Company will over recover its costs associated with wind integration. Customers
5 are further protected by the Energy Cost Adjustment Mechanism (“ECAM”).

6 **Q. Did the wind study also identify additional costs associated with day-ahead**
7 **forecast errors for wind and load?**

8 A. Yes. Using the results of the Wind Study, the Company modeled \$0.72/MWh for
9 day-ahead forecast errors, or system balancing costs in the NPC study.

10 **Q. Did the Company reasonably model the Wind Study results in GRID for the**
11 **current filing?**

12 A. Yes. The results from GRID reasonably reflect the impact of integrating wind
13 generation into the Company’s portfolio. The Wind Study addressed all the issues
14 raised by various parties in Idaho and other states, such as reserve requirements
15 being modeled within GRID, the requirements for wind generation being
16 considered net of load, studies supporting the impact of integrating generation
17 from wind facilities, and the quality of data used to prepare the study. However,
18 given the limitation of data inputs to the normalized studies, I believe that the
19 GRID-modeled impact of integrating wind resources may understate the real
20 costs. For example, the GRID model uses expected wind profiles of the wind
21 projects which lack the variability reflected in the actual operations of the wind
22 projects.

1 **Q. Have you validated the Wind Study against the Company's actual**
2 **experience?**

3 A. Yes. The Company computed the actual reserves carried during 2010 to meet
4 spinning and supplemental contingency reserves, and regulation reserves from
5 recorded data. The actual regulation reserves carried on the system during 2010
6 was 629 MW. This is 96 MW higher than the 533 MW calculated in the Wind
7 Study and modeled in GRID, thereby validating the Wind Study results as
8 reasonable, if not low.

9 **Q. Does the Company include system balancing costs for the non-owned wind**
10 **projects and for projects located in the BPA's balancing area?**

11 A. No, the normalized NPC in the current filing do not include system balancing
12 costs for the wind projects located in the Company's balancing areas that the
13 Company neither owns nor purchases the output. This is based on the assumption
14 that the entities that own and/or operate those wind projects will balance their
15 own system prior to handing over their generation schedule to the Company.
16 However, following that same logic, the normalized NPC include system
17 balancing costs for projects located in BPA's balancing area: Leaning Juniper and
18 Goodnoe Hills.

19 **Q. Has the Company included wind integration costs for the non-owned wind**
20 **projects located within its balancing area in this filing?**

21 A. Yes. As discussed in the 2010 GRC, the Company is required to provide wind
22 integration service to wholesale customers under federal law; the Company's
23 Open Access Transmission Tariff (OATT) does not allow the Company to charge

1 for this service. However, the Company will file a wholesale transmission rate
2 case with FERC on or before June 1, 2011, in which it will propose a new
3 Schedule 3A that, if approved by FERC, would allow the Company to charge
4 these types of generators for regulation service in the future.

5 **Q. Does the Company believe that FERC will approve its new Schedule 3A?**

6 A. Yes, although it is not known and measurable at this time. However, in Order No.
7 890-A, the FERC allowed transmission providers to propose to assess regulation
8 charges to both generators selling in the BAA and those selling outside their
9 BAA. This latter category are what are considered non-owned generation in
10 GRID. The FERC stated that it would consider such proposals on a case-by-case
11 basis. The FERC has approved transmission provider proposals to recover the
12 costs of capacity associated with the provision of generator imbalance service
13 through a proposed schedule seeking charges for providing generator regulation
14 and frequency response service.

15 Moreover, The Company's proposed Schedule 3A is consistent with the
16 FERC's November 18, 2010, Notice of Proposed Rulemaking ("NOPR") on the
17 integration of Variable Energy Resources ("VERs"), in which FERC proposed a
18 generic rate schedule for the rates, terms, and conditions that apply to providing
19 generator regulation and frequency response service. PacifiCorp's new Schedule
20 3A allows PacifiCorp to close the cost recovery gap with the type of ancillary
21 service that FERC has contemplated and accepted in the past for other public
22 utilities. A transmission customer subject to Schedule 3A must either (1) take
23 generator regulation and frequency response service from PacifiCorp or (2)

1 demonstrate that it has satisfied its regulation service obligation.

2 **Q. Will this new wholesale ancillary service charge, if approved by FERC,**
3 **recover the costs of integrating wholesale customer wind projects?**

4 A. Yes. Regulation service is a type of energy reserve service necessary for
5 integrating resources into the transmission system. Regulation reserves account
6 for the variability of load and generation on the transmission system on a
7 moment-to-moment basis and over the course of an hour. The new Schedule 3A
8 would apply to resources when they are exporting to load in other balancing
9 authority areas and would result in additional revenues from non-owned resources
10 that are not delivering power to serve the Company's native load.

11 **Q. Do Idaho customers benefit from the Company providing Schedule 3A type**
12 **services to the non-owned generation?**

13 A. Yes. As a balancing area authority, the Company owns and operates an extensive
14 transmission network that it is required to operate safely and reliably for all of its
15 customers, keeping all resources and loads in balance on a moment-to-moment
16 basis. In addition, the Company is mandated to make its transmission network
17 available to all generators in an open access and non-discriminatory fashion. By
18 providing regulation and frequency response service in addition to other
19 transmission related services as a balancing authority, the Company ensures that
20 its customers are served by a reliable system, with diverse resources. Moreover,
21 any transmission revenues received from non-owned generation, which pays
22 wheeling to the Company, are credited against retail revenue requirement and
23 therefore have the effect of lowering the cost of service for retail customers. If the

1 FERC approves the new Schedule 3A, retail customers will also receive
2 additional revenues from providing service to these wholesale wheeling
3 customers.

4 **Q. Do you have anything to add with regard to the issue of wind integration**
5 **costs associated with wholesale transmission customers?**

6 A. Yes. I have been advised that because FERC has exclusive authority over the
7 transmission and sale of electricity in interstate commerce pursuant to the Federal
8 Power Act, under the Supremacy Clause of the United States Constitution:

9 a state utility commission setting retail rates must allow, as
10 reasonable operating expenses, costs incurred as a result of paying
11 a FERC-determined wholesale price . . . Once FERC sets such a
12 rate, a State may not conclude in setting retail rates that the FERC-
13 approved wholesale rates are unreasonable.⁷

14 Correspondingly, the Supremacy Clause would also require a state
15 commission to allow as reasonable operating expenses costs that are incurred as a
16 result of operating consistent with a FERC-approved tariff. Based upon these
17 principles, I understand that because the Company is required by federal law to
18 interconnect with wholesale transmission customers under the terms of the
19 OATT, federal preemption precludes disallowing the associated costs, such as the
20 costs regulation and frequency response services.

⁷*Nantahala Power and Light Co. v. Thornburg*, 476 U.S. 953, 956-966 (1986).

1 **Q. Does the Company propose to update its filing in its rebuttal testimony for**
2 **changes in net power costs, such as new contracts, fuel costs and the Official**
3 **Forward Price Curve, irrespective of whether these changes increase or**
4 **decrease net power costs?**

5 A. Yes. This ensures that the Commission has the most accurate and current
6 information available to it in setting rates for the test period.

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

8 A. Yes.