

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE)
APPLICATION OF ROCKY) **CASE NO. PAC-E-11-07**
MOUNTAIN POWER FOR)
AUTHORITY TO INCREASE RATES) **Direct Testimony of Hui Shu**
BY \$11.0 MILLION TO RECOVER)
DEFERRED NET POWER COSTS)
THROUGH THE ENERGY COST)
ADJUSTMENT MECHANISM)

ROCKY MOUNTAIN POWER

CASE NO. PAC-E-11-07

February 2011

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

3 A. My name is Hui Shu, my business address is 825 N.E. Multnomah, Suite 600,
4 Portland, Oregon 97232, and my present position is Manager, Net Power Costs.

5 **Qualifications**

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

7 A. I received an undergraduate degree in Electrical Engineering and finished training
8 in the program for Masters in Business Administration from University of
9 Shanghai for Science and Technology. I received a PhD degree in Systems
10 Science with a focus on Econometrics from Portland State University. I have
11 worked for PacifiCorp since 1992 and have held positions in the commercial and
12 trading and regulatory areas. I accepted my current position as manager of net
13 power costs in February 2008.

14 **Q. Please describe your current duties.**

15 A. I am responsible for the coordination and preparation of net power cost and
16 related analyses used in regulatory filings. In addition, I represent the Company
17 on power resource and other related issues in regulatory proceedings across the
18 Company’s six-state service territory.

19 **Summary of Testimony**

20 **Q. Will you please summarize your testimony?**

21 A. I am sponsoring testimony supporting the Company’s request to increase Tariff
22 Schedule 94 to recover costs of approximately \$12.8 million resulting from the
23 implementation of the Company’s Idaho Energy Cost Adjustment Mechanism

1 (“ECAM”) for the 12-month period ended November 2010. In doing so, I present
2 the background and calculation of the Company’s ECAM and describe the actual
3 net power costs (“NPC”) incurred by the Company to serve retail load for the
4 historical 12-month period ended November 30, 2010 (“Deferral Period”). The
5 proposed increase to Tariff Schedule 94 is approximately \$11.0 million,¹ or an
6 average of 7.4 percent to Idaho customers.

7 **ECAM Background**

8 **Q. Please briefly describe the Company’s ECAM authorized by the**
9 **Commission.**

10 A. In Order No. 30904 dated September 29, 2009, in the Company’s Case No. PAC-
11 E-08-08, the Commission approved the stipulation entered into by the
12 Commission Staff, the Idaho Irrigation Pumpers Association, Monsanto and the
13 Company that set up the structure and content of the ECAM mechanism. The
14 ECAM, which appears as a separate line item on customer bills, defers the
15 difference between actual NPC incurred by the Company to serve Idaho
16 customers over a specified period and a base NPC level established through a
17 general rate case proceeding. Where actual NPC is greater than the base NPC, the
18 difference is charged to customers through the ECAM (administered through
19 Electric Service Schedule No. 94). Conversely, where the base NPC is greater
20 than Actual NPC, the difference is credited to customers. In addition to the

¹ The Company was authorized to set present Schedule 94 rates that were designed to recover approximately \$2.0 million. Rates in the 2010 ECAM adjustment, Case No. PAC-E-10-01 were set using the Company’s then-most recent general rate case test period, 12 months ending December 2007. In this current docket, the Company is using the test period from its current 2010 Rate Case, Case No. PAC-E-10-07, 12 months ending December 2010. Using this most recent test period, present Schedule 94 will collect approximately \$1.8 million. As a result, the proposed recovery of approximately \$12.8 million in the current filing results in a net rate increase to customers of approximately \$11.0 million.

1 variance between actual and base NPC, the ECAM reflects the impact of
2 differences in the deferral period between actual and base period retail load, a
3 credit for SO₂ revenues, an adjustment for the treatment of coal stripping costs
4 and a renewable resource adder that reflects generation from new renewable
5 resources that have not been included in rates during the deferral period. Pursuant
6 to the terms of the stipulation, the annual deferral period for the ECAM is
7 December 1 to November 30; the Company is required to file by February 1 each
8 year subsequent to the deferral period an application with the Commission to
9 adjust the ECAM rate effective April 1.

10 **ECAM Calculation**

11 **Q. Please describe the Energy Cost Adjustment Mechanism as calculated in**
12 **Exhibit 1.**

13 A. In this application for the Deferral Period of December 1, 2009 to November 30,
14 2010, the Company compared the actual system net power costs (“Actual NPC”) to
15 the net power costs embedded in rates (“Base NPC”) from Case No. PAC-E-
16 08-07 (“2008 Rate Case”), on a monthly basis and deferred the differences into an
17 ECAM balancing account. This comparison is made on a system basis and in a
18 dollar per megawatt-hour rate. Exhibit 1 details the ECAM calculation and
19 contains supporting information, portions of which are confidential.

20 **Q. How are the Base NPC and Actual NPC dollar per megawatt-hour rates**
21 **calculated?**

22 A. With respect to the Base NPC rate, the Company started with the net power costs
23 of approximately \$982 million approved by the Commission in Order No. 30783

1 from the 2008 Rate Case. The Company then took the monthly NPC dollar
2 amount from that case and divided it by the monthly normalized load to express
3 the costs on a dollar per megawatt-hour basis (Exhibit 1, line 1). The Actual NPC
4 rate on a dollar per megawatt-hour basis is calculated by taking the monthly
5 Actual NPC dollar amount and dividing it by the actual monthly system load
6 (Exhibit 1, line 4).

7 **Q. Please describe how the NPC deferral is determined.**

8 A. The calculation of the deferral is done on a monthly basis by subtracting the Base
9 NPC rate from the Actual NPC rate. The resulting monthly NPC rate differential
10 (Exhibit 1, line 5) is then multiplied by actual Idaho retail load at input, excluding
11 the tariff contract load (Exhibit 1, lines 6 and 7) to calculate the NPC differential
12 for deferral (Exhibit 1, line 8). For the 12-month period ending November 2010
13 the NPC differential for deferral was approximately \$6.1 million.

14 **Q. Why is the tariff contract load excluded in the current ECAM calculation?**

15 A. In the 2007 general rate case, Case No. PAC-E-07-05, the Commission approved
16 a stipulation including electric service agreements with specific planned rate
17 increases for two tariff contract customers through December 31, 2010. The
18 Company committed not to seek further rate changes for the contract customers
19 that would be effective prior to January 1, 2011 and is not proposing any
20 modifications to those rate plans in this Application. As a result, only the standard
21 tariff customers' load is included in the ECAM calculation while the tariff
22 contract customers' load is excluded from the calculation. The tariff contract
23 customers will be responsible for their share of the ECAM deferred costs

1 beginning January 1, 2011 forward and will be included in the Company's ECAM
2 application filed February 1, 2012.

3 **Q. What types of costs are included in the NPC differential for deferral?**

4 A. The NPC differential for deferral captures all components of net power costs as
5 defined in the Company's general rate case proceedings and modeled by the
6 Company's production dispatch model ("GRID"). Specifically, Base NPC and
7 Actual NPC include amounts booked to the following FERC accounts:

- 8 Account 447 – Sales for resale, excluding on-system wholesale sales and
9 other revenues that are not modeled in GRID
- 10 Account 501 – Fuel, steam generation; excluding fuel handling, start up
11 fuel/gas², diesel fuel, residual disposal and other costs that
12 are not modeled in GRID
- 13 Account 503 – Steam from other sources
- 14 Account 547 – Fuel, other generation
- 15 Account 555 – Purchased power, excluding BPA residential exchange
16 credit pass-through if applicable
- 17 Account 565 – Transmission of electricity by others

18 **Q. In addition to the comparison of Actual NPC to Base NPC, what other
19 components are included in the ECAM?**

20 A. There are three additional components included in the ECAM calculations: (i)
21 Load Growth Adjustment Rate ("LGAR") revenues, (ii) credit for any SO₂
22 allowance sales, and (iii) a renewable resource adder. In addition, in Order No.
23 30987 in the Company's Case No. PAC-E-09-08, the Commission granted
24 authorization of the Company's application to defer costs associated with coal
25 mine stripping activities recorded under the Financial Accounting Standards
26 Board ("FASB") Emerging Issues Task Force standard 04-6 ("EITF 04-6").

² Start up fuel is accounted for separately from the primary fuel for steam power generation plants. Start up costs are not accounted for separately for natural gas plants, and therefore all fuel for natural gas plants is included in the determination of both Base NPC and Actual NPC.

1 Based on this authorization, the Company records to Other Regulatory Assets the
2 mine stripping costs, and amortizes the costs to Fuel Expenses when coal is
3 extracted and consumed. In this filing, the Company has included adjustments to
4 reflect this treatment.

5 **Q. Please describe the LGAR revenues and how they impact the ECAM.**

6 A. The calculation of LGAR revenues is a symmetrical adjustment for any over or
7 under collection of the Company's production plant related revenue requirement,
8 excluding NPC, due to variances in Idaho load. In Commission Order No. 30904,
9 the Commission approved a symmetrical LGAR of \$17.48 per megawatt-hour.
10 LGAR revenues are calculated by subtracting Idaho's load at input established in
11 the 2008 Rate Case ("Base Load" shown in Exhibit 1, line 9), from actual Idaho
12 load at input ("Actual Load" shown in Exhibit 1, lines 6 and 7). The difference
13 (Exhibit 1, line 10) is then multiplied by the LGAR of \$17.48 (Exhibit 1, line 11)
14 to arrive at the LGAR revenues (Exhibit 1, line 12) of approximately \$5.3 million
15 for the 12-month Deferral Period.

16 **Q. How is SO₂ sales revenue included in the ECAM?**

17 A. Line 13 of Exhibit 1 contains the total Company SO₂ sales revenue during the
18 Deferral Period. Based on Idaho's System Energy allocation factor ("SE")
19 authorized by the Commission from the 2008 Rate Case, line 15 of Exhibit 1 is
20 Idaho's allocated share of the SO₂ sales revenue. Idaho's allocated share of the
21 SO₂ sales revenue is further prorated to exclude the tariff contract customers' load
22 on line 16 of Exhibit 1. The resulting SO₂ sales revenue on line 17 of Exhibit 1 is
23 credited against the NPC differential for deferral. For the 12-month Deferral

1 Period, the total SO₂ sales revenue credit is a \$93,906 reduction to the NPC
2 deferral balance.

3 **Q. How is the adjustment for the accounting pronouncement EITF 04-6**
4 **included in the ECAM?**

5 A. Line 18 of Exhibit 1 reflects the Idaho allocated differences between excluding
6 coal stripping costs incurred by the Company and recorded on the Company's
7 books pursuant to the guidance of the accounting pronouncement EITF 04-6, and
8 the amortization of the coal striping costs when the coal was excavated and
9 consumed. Idaho's allocated share is further prorated to exclude the tariff contract
10 customers' load on line 19 of Exhibit 1. The resulting EITF 04-6 deferral
11 adjustment on line 20 of Exhibit 1 is added to the NPC differential for deferral.
12 For the 12-month Deferral Period, the total EITF 04-6 coal stripping deferral
13 adjustment is a \$108,588 reduction to the NPC deferral balance.

14 **Q. Is the deferral subject to a sharing ratio between the Company and**
15 **customers in the ECAM?**

16 A. Yes. The ECAM includes a symmetrical sharing ratio where customers pay or
17 receive 90 percent of the ECAM deferral balance and the Company is responsible
18 for the remaining 10 percent. Line 23 of Exhibit 1 reflects the customers' 90
19 percent share of the monthly deferral on line 21 of Exhibit 1. For the 12-month
20 Deferral Period, the customers' share of the deferral balance is approximately
21 \$10.0 million. The remaining balance of approximately \$1.1 million is not
22 included in the deferral calculation and is not recoverable from customers.

1 **Q. Is the deferral balance adjusted for a renewable resource adder?**

2 A. Yes.

3 **Q. Please describe the renewable resource adder for resources not yet in rates.**

4 A. The renewable resource adder recognizes that the Company has made significant
5 investment in renewable generation resources that are not yet being recovered in
6 Idaho rates, and that these resources are providing benefits to customers through
7 the near-zero cost energy generation included in the Actual NPC. Therefore, from
8 the effective date of the ECAM to the date when the investment of these resources
9 is included in rates, the ECAM includes a renewable generation investment
10 adjustment. The adjustment is based on an authorized amount of \$55.00 per
11 megawatt-hour multiplied by the actual megawatt-hour output generated by those
12 renewable resources that were not included in rates during the Deferral Period
13 (Exhibit 1, line 24). Line 26 of Exhibit 1 reflects this adjustment on a total
14 Company basis. The total Company amount is allocated to Idaho (Exhibit 1, line
15 28) based on the System Generation allocation factor (“SG”), which is further
16 prorated to the tariff customer load (Exhibit 1, line 30). The renewable resource
17 adder results in a cost to customers of approximately \$2.7 million for the 12-
18 month Deferral Period.

19 **Q. Which renewable generation projects are included in the renewable resource**
20 **adder?**

21 A. The renewable generation resources included in this application are Glenrock,
22 Glenrock III, Seven Mile, Seven Mile II, Rolling Hills, High Plains, McFadden
23 Ridge, and Dunlap wind generation facilities. These resources were included in

1 the Company's application in Case No. PAC-E-10-07 ("2010 Rate Case") and,
2 subject to final Commission approval and inclusion of these investments in rate
3 base, accrual of costs into the ECAM for the renewable resource adder will
4 terminate with the effective date of the rate change in the 2010 Rate Case.

5 **Q. What is the total ECAM deferred balance as calculated in Exhibit 1?**

6 A. The total ECAM deferral balance is the customers' share of the NPC differential
7 for deferral balance, the SO₂ allowance sales, LGAR, and EITF 04-6 adjustment
8 plus the renewable resource adder. That is, the ECAM balance in the current
9 application at November 30, 2010 is approximately \$13.6 million, including \$10.0
10 million related to the customers' share of deferral balance, \$2.7 million of
11 renewable resource adder, approximately \$760,000 of uncollected balance from
12 the Company's ECAM filing in 2010 and interest on the monthly ECAM balances
13 that is determined based on the Commission authorized rate for customer deposits
14 at two percent in 2009 and one percent beginning in January 2010. The ECAM
15 balance is shown on line 38 of Exhibit 1.

16 **Q. In your opinion does the calculation of the \$13.6 million deferred NPC**
17 **adjustment proposed in this application comply with the parameters of the**
18 **Idaho ECAM as approved by the Commission in Case No. PAC-E-08-08?**

19 A. Yes.

20 **Q. Is the Company requesting a rate increase to recover the full \$13.6 million**
21 **deferral?**

22 A. No. The Company has subtracted the approximate \$760,000 under collection
23 referenced previously from the \$13.6 million November 2010 balance as it is

1 expected that the under collection will largely be recovered through Schedule 94
2 rates from December 1, 2010 to March 31, 2011. Any over or under collection of
3 the original \$2.0 million deferral will be addressed in future ECAM filings.

4 **Q. Please summarize the components of the Deferred ECAM Balance.**

5 A. The components making up the deferred ECAM balance as detailed in Exhibit 1
6 are reflected in the following table:

Summary Table of Deferred ECAM Balance

NPC Differential for Deferral	\$ 6,073,522
LGAR	5,286,046
SO2	(93,906)
EITF 04-6 Adjustment	(108,588)
Total	<u>\$ 11,157,074</u>
	90%
Customer Responsibility	\$ 10,041,366
Renewable Resource Adder	2,696,763
Unamortized Previous Balance	760,036
Interest	61,885
November 2010 Deferral	<u>\$ 13,560,051</u>
Less: Unamortized 2010 ECAM Balance	\$ (760,036)
Proposed Balance for Recovery	<u>\$ 12,800,015</u>

7 **Actual NPC - Base NPC Comparison**

8 **Q. How does the Actual NPC differ from the Base NPC for this deferral period?**

9 A. The Base NPC that is approved by the Commission and included in rates is
10 approximately \$982.0 million on a total Company basis. Total adjusted Actual
11 NPC during the deferral period beginning December 1, 2009 and ending
12 November 30, 2010 is \$1.172 billion, which is approximately \$190 million higher
13 than what was included in rate during the Deferral Period.

14 **Q. Please explain why Actual NPC are adjusted.**

15 A. The Actual NPC recorded on the Company's books are adjusted to remove entries
16 that are not included in the determination of the Company's Base NPC for

1 regulatory purposes, such as adjustments made to correct entries in months
2 outside the current ECAM period, or prior Commission approved adjustments,
3 such as the revenue imputation of the sales contract with Sacramento Municipal
4 Utility District.

5 **Q. What are the primary drivers that cause the Actual NPC to be different from**
6 **the Base NPC in rates during the Deferral Period?**

7 A. The differences in NPC are mainly the result of the timing difference between
8 Actual NPC and Base NPC and changes in costs in the actual period that were not
9 reflected in the Base NPC. The Base NPC has a test period of calendar 2008,
10 while Actual NPC is for December 2009 through November 2010. Between the
11 base period and the actual period, several wholesale sales and purchase contracts
12 have expired and new contracts have become effective. Changes in the
13 Company's resource portfolio and market prices also have led to differences
14 between Actual NPC and Base NPC.

15 **Q. Could you give some example of these changes?**

16 A. Yes. Some examples include:

17 • In November 2009, the original contract between the Company and the Grant
18 Public Utility District ("PUD") for the generation from the Mid Columbia
19 Wanapum project expired. Because this contract was priced at the cost of the
20 Wanapum project, NPC in the Deferral Period are higher due to higher costs
21 of the replacement power. The amount of reduction in purchased power due to
22 expiration of this contract nets to approximately 590,000 megawatt-hours in
23 the Deferral Period. The higher costs of the replacement power are somewhat

1 mitigated by the increase in revenues from the Reasonable Portion of the
2 contract with Grant PUD.

- 3 • A low-priced formula power transfer (“FPT”) wheeling contract with the
4 Bonneville Power Administration (“BPA”) expired and was converted to a
5 higher priced point-to-point (“PTP”) contract in November 2009. The Deferral
6 Period also includes additional wheeling expenses to transfer generation from
7 the Chehalis plant to the Company’s load areas, as well as increases in wind
8 integration costs that BPA charges for the Company’s wind generation
9 facilities located in the BPA’s balancing authority area: Leaning Juniper and
10 Goodnoe Hills. Increases in BPA wheeling expenses are approximately \$18.8
11 million.

- 12 • The Idaho Power Company has restructured the wheeling contracts with the
13 Company for transferring generation from Jim Bridger plant to the Company’s
14 load areas, which are now priced at relatively higher PTP rates. The
15 restructured contracts increased wheeling expenses by approximately \$7.0
16 million.

- 17 • Both third party coal purchase expenses and captive mine costs have
18 increased. For example, the coal prices at the Naughton plant increased by
19 approximately \$12 million due to both a price reopener under the long-term
20 coal supply agreement with Chevron Mining and the escalation of the
21 producer price index under the previous contract; the coal prices at the Hunter
22 plant increased by approximately \$7 million due primarily to a fixed price
23 increase under the Sufco contract; the coal prices at the Huntington plant

1 increased by approximately \$8 million, predominantly resulting from the
2 higher operating costs during July through November 2010 while the longwall
3 system was being reconstructed; and the coal prices increased by
4 approximately \$31 million at the Bridger Plant as the result of higher Bridger
5 Coal Company production costs, a new coal supply agreement with Black
6 Butte and a new rail agreement with the Union Pacific Railroad.

- 7 • The actual hydro generation from the Company owned resources is lower than
8 what is reflected in the Base NPC by approximately 650,000 megawatt-hours.
- 9 • The availability of the Company's thermal plants are lower than what was
10 reflected in the Base NPC, in addition to the added requirement to fulfill the
11 requirements to integrate the Company's increasing amount of wind
12 generation into the system. The combined impact of these reduced thermal
13 generation by approximately 3.8 million megawatt-hours, as compared with
14 what is reflected in Base NPC.

15 All of these changes have caused the Actual NPC to be higher than the Base NPC.

16 **Q. Are the increases in NPC offset by other components of the NPC?**

17 A. Yes. Cal ISO fees and short term wheeling expenses are lower in the deferral
18 period. Also, as discussed above, several new wind resources came online since
19 the Company's 2008 Rate Case, which provided power at nearly zero variable
20 costs. The generation from these additional wind facilities during the Deferral
21 Period is approximately 1.5 million megawatt-hours.

1 **Schedule 94 - Energy Cost Adjustment**

2 **Q. How is the deferred NPC adjustment allocated to retail tariffs?**

3 A. Pursuant to Schedule 94, the deferred ECAM balance is allocated to all tariff rate
4 schedules based on delivery voltage levels adjusted for line losses as established in
5 the 2010 Rate Case. An overall average rate is developed by dividing the
6 November 30, 2010 ECAM balance by the line loss adjusted load. This average
7 rate is then multiplied by the primary, secondary, and transmission line loss
8 adjusted loads to calculate the amount each voltage service level would collect of
9 the deferred balance. This revenue by voltage level is then divided by the
10 corresponding metered loads by voltage service level to arrive at a rate per service
11 voltage level. These rates are then applied to the voltage service level loads of each
12 rate schedule to calculate the revenue to be collected by rate schedule. This
13 allocation recognizes the differences in the cost to serve different levels of voltage.

14 **Q. Please describe Exhibit 2.**

15 A. Exhibit 2 illustrates the metered loads, the line loss adjusted loads, the allocation of
16 the deferred NPC price change, and the percentage change by rate schedule based
17 on present revenues ordered in the Company's 2010 Rate Case.

18 **Q. Please describe Exhibit 3.**

19 A. Exhibit 3 is the proposed tariff Schedule 94, Energy Cost Adjustment, designed to
20 collect approximately \$12.8 million in ECAM deferred balance. Any under or over
21 recovery will continue to be included in the ECAM deferred balance and trued-up
22 over time. Schedule 94 shows the electric service schedules currently subject to the
23 ECAM deferral and their proposed rates based on customer delivery voltage.

1 Schedule 94 is a separate line item, or rider, on customer bills that is adjusted
2 annually on April 1 following Commission approval.

3 **Q. What is the monthly bill impact to the average residential customer of the**
4 **proposed Schedule 94 rates?**

5 A. Based on the net increase of approximately \$11.0 million, the average Schedule 1
6 residential customer using 839 kWh per month will see a monthly bill increase of
7 approximately \$5.03, or 6.1 percent. This compares to the overall average increase
8 for all customer classes of 7.4 percent.

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

10 A. Yes.