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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE	)	
APPLICATION OF ROCKY	)	**CASE NO. PAC-E-10-07**
MOUNTAIN POWER FOR	)	
APPROVAL OF CHANGES TO ITS	)	**Direct Testimony of Hui Shu**
ELECTRIC SERVICE SCHEDULES	)	
AND A PRICE INCREASE OF $27.7	)	
MILLION, OR APPROXIMATELY	)	
13.7 PERCENT	)	

ROCKY MOUNTAIN POWER

CASE NO. PAC-E-10-07

May 2010

Q. Please state your name, business address and present position with PacifiCorp ("Company").

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

Qualifications

Q. Briefly describe your educational and professional background.

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

Q. Please describe your current duties.

A. I am responsible for the coordination and preparation of net power cost studies and related analyses used in retail price filings. In addition, I represent the Company on various net power cost related issues with intervenor and regulatory groups associated with the six state regulatory commissions to whose jurisdiction the Company is subject.

Purpose of Testimony

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

A. I present the Company's net power costs for the 12-month period ending December 2010. Specifically, my testimony:

- Sponsors the GRID model net power cost report that supports this filing;

- Describes the primary drivers of the increase in the Company's net power costs;
- Describes modeling enhancements addressing hydro resources; and
- Discusses the wind integration charge included in the Company's filing.

Net Power Cost Results

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

A. The normalized net power costs ("NPC") for the twelve months ending December 2010 are approximately $69.2 million on an Idaho allocated basis, or $1.07 billion system-wide as presented in confidential Exhibit No. 40. The allocation of total Company NPC to Idaho is presented in Exhibit No. 2 in Company witness Mr. Steven R. McDougal's direct testimony.

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

A. They will set the new base NPC for purposes of the Energy Cost Adjustment Mechanism ("ECAM") and will be trued-up to actual NPC consistent with the mechanics of the ECAM.

Q. How do proposed NPC compare with the NPC that the Commission authorized in the Company's last general rate case, Case No. PAC-E-08-07?

A. The NPC authorized in Case No. PAC-E-08-07 were $982 million on a total Company basis or $66.1 million on an Idaho allocated basis. On a total Company basis, NPC have increased approximately $87.7 million from $982 million to $1.07 billion. Idaho's allocated portion of NPC in the current filing is approximately $3.1 million higher than the NPC currently included in customers' rates, which is the combined result of increases in the total Company NPC and decreases in Idaho's allocation factor.

Primary Drivers Increasing Net Power Costs

Q. What are the primary drivers of the increase in NPC?

A. The factors that are driving NPC increases in the test period ending December 2010 include:

- Increases in coal costs;
- Increased firm wheeling expenses;
- Expiration of low-cost long-term firm power purchases and high-priced long-term sales contracts;
- Lower hydro generation; and
- Increases in wind integration costs.

The offsetting factors include:

- Lower system load; and
- Additional wind generation.

Q. Please explain the Company's coal costs increases.

A. The costs of coal supplied to the coal-fired generating facilities from both the Company's captive mines and contracts with third parties have increased approximately $116 million on a total Company basis from what were included in the NPC that are currently in rates. For a detailed explanation of these increases, please refer to the direct testimony of Company witness Ms. Cindy A. Crane.

Q. What are the primary reasons for the increases in wheeling expenses?

A. Wheeling expenses increased due to the expiration of low-priced formula power transfer ("FPT") wheeling contracts with the Bonneville Power Administration ("BPA"). As these FPT contracts expire, they are being replaced with new wheeling contracts with BPA that are higher-priced point-to-point ("PTP") and network-integration ("NT") contracts. The increases also include expenses for additional contracts to wheel generation from the Chehalis gas-fired plant and the Goodnoe Hills wind plant to the Company's load areas. Also, Idaho Power Company has adjusted its wheeling rate for the contracts with the Company associated with delivering generation from the Jim Bridger plant to the Company's load areas. These changes to wheeling expenses increase NPC by approximately $16.5 million on a total Company basis.

Q. **Are the BPA wind integration charges included in the wheeling expenses?**

A. Yes. The BPA wind integration charges are recorded in the Company's wheeling expense account. These expenses were included in the Company's total wind integration charges in the last case. In addition, BPA has increased its wind integration charge from $0.68 per kW-month to $1.29 per kW-month based on the results of BPA's 2010-2011 transmission rate case.

Q. **How do expiring power purchase and sales contracts impact net power costs?**

A. The cost of the replacement power for expiring purchase contracts could be higher or lower, depending on whether the price of the expired power purchase contract was below or above current market prices. Likewise, the revenue credits of additional wholesale sales could be lower or higher, depending on whether the price of the expired power sales contract was above or below current market prices.

Q. Please highlight some of the key contract changes in the net power costs.

A. Revenues from wholesale sales are credited against expenses included in NPC. This filing reflects the expiration of sales contracts with NV Energy (Sierra Pacific), Salt River Project, and a reduction in the energy take of the sales contract with the Public Service Company of Colorado, per the contract terms. Because of the relatively high prices of these sales contracts when compared to current market prices, the combined impact of the expiration of these sales contracts increases NPC by approximately $37.0 million on a total Company basis. The price of the contract with BPA for capacity has increased based on BPA's 2010-2011 Wholesale Power Rate Schedule, which increases NPC by approximately $10.6 million on a total Company basis. As an offset to rising power costs, several relatively high-priced purchase contracts have expired, which reduces NPC by approximately $31.5 million on a total Company basis. This filing also includes the purchase agreements with Three Buttes Windpower, LLC and Top of the World Wind Energy, LLC for wind generation from those projects. For further discussion on these two contracts, please refer to Mr. Stefan A. Bird's direct testimony.

Q. Are there significant changes to the Company's purchase contracts for generation from the Mid-Columbia projects?

A. Yes. In November 2009, the nearly 50 year old contract between the Company and the Grant Public Utility District ("Grant PUD") under which the Company purchased a share of the output of the Wanapum hydro-electric project expired. This contract was priced at the cost of the Wanapum project, which is significantly below current market prices, and accordingly, expiration of the contract increased NPC in the test period due to higher costs of the replacement power. The cost increase from the replacement of this contract is mitigated somewhat by the increase in revenues from the Reasonable Portion of the contract with Grant PUD. The expiration of the Meaningful Priority from Grant PUD also reduces NPC because it was priced at the then-market price plus a premium. The net impact of these changes reduces NPC by approximately $3.4 million on a total Company basis.

Q. How does decreased hydro generation impact the Company's NPC?

A. Because hydro generation is a zero cost resource in the NPC calculations, the reduction in hydro causes the NPC to increase. This filing reflects a decrease in hydro generation of 0.1 million megawatt hours, or 2.9 percent, when compared to the amount included in the Company's last rate filing. The reduction in hydro generation increases NPC by approximately $4.9 million on a total Company basis. I will discuss the changes in hydro generation later in my testimony. All things being equal, reduced hydro generation will require the Company to re-dispatch the system utilizing additional higher cost thermal resources and by making additional wholesale market purchases and reduced wholesale market sales.

Q. Have the wind integration costs increased?

A. Yes. In the current filing, the Company uses $6.50 per megawatt-hour, which was authorized by the Commission in Case No. PAC-E-09-07, to calculate the costs of integrating the wind generation into the Company's system. In the

Company's 2008 general rate case, the wind integration charge was based on the results from the Company's 2007 Integrated Resource Plan (IRP) at $1.14 per megawatt-hour for all wind generation. Also, in that case the wind integration costs for the generation from the Leaning Juniper and Goodnoe Hills located in the BPA's control area were calculated using the same rate at $1.14 per megawatt-hour, except the last two months in the test period when BPA added a wind integration charge in its transmission tariff rates at $0.68 per kW-month. I will discuss further later in my testimony about the Company's wind integration costs, and the application of the $6.50 per megawatt-hour in this filing.

Q. **Are there other factors decreasing some of these NPC increases?**

A. Yes. System load is lower and the wind generation is higher in the current filing.

Q. **How much has the Company's system load decreased?**

A. The system load in the current filing is about 0.5 million megawatt-hours (approximately one percent) lower than what was in the 2008 general rate case, which reduces the NPC by approximately $20.6 million on a total Company basis. Dr. Peter C. Eelkema's direct testimony explains the changes in system load.

Q. **How much additional wind generation is included in the test period as compared with what was in Case No. PAC-E-08-07?**

A. The NPC in the current filing includes approximately 1.9 million megawatt-hours additional wind generation from eight Company-owned wind projects since the Company's last general rate case. This NPC study includes generation from the 99-megawatt Glenrock, 39-megawatt Glenrock III, 99-megawatt High Plains, 99-megawatt Rolling Hills, 99-megawatt Seven Mile Hill, 19.5-megawatt Seven Mile

Hill II and 28.5-megawatt McFadden Ridge I wind projects that are all located in Wyoming. Please refer to the direct testimony of Mr. Mark R. Tallman for additional detail about these resources. The NPC also includes the 111-megawatt Dunlap project located in Wyoming that will be in service in November 2010 but assumed to be in-service for a full twelve months for the current filing. Please refer to the direct testimony of Mr. Bird for additional detail about the Dunlap project. For the Company-owned wind facilities, the variable cost is the costs to integrate the intermittent wind generation into the Company's resource portfolio.

Q. Did the Company adjust for startup costs related to the gas-fired units?

A. Yes. Because the GRID model does not capture the startup costs of the gas-fired units that are not included in any other Federal Energy Regulatory Commission accounts, a line item is added to the NPC report to capture the startup fuel costs of the gas-fired units.

Q. Has the Company changed its topology modeled in GRID?

A. Yes. To reflect the transmission constraints in the Wyoming area and to ensure the reliability of the transmission network in the area governed by the Western Electricity Coordinating Council ("WECC"), the constraint in the cut plane named Tot 4A in Wyoming has been redefined by PacifiCorp Transmission department and approved by WECC. As a result, the previously modeled transmission area of "Wyoming" in GRID has been redefined.

Q. Did the Company model the impact of the new transmission addition between Populus and Terminal?

A. Yes. The addition of the Populus to Terminal line increases the transmission capacity across Path C from southeast Idaho to northern Utah by approximately 780 megawatts. The additional transmission capacity makes it possible to better utilize the market price differentials between the east and west sides of the Company's system, reduces reliance on additional purchases of transmission from third parties, and improves reliability. For further details, please refer to the direct testimony of Company witnesses Mr. John A. Cupparo and Mr. Darrell T. Gerrard.

Determination of NPC and Model Inputs and Outputs

Q. Please explain NPC.

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

Q. Please explain how the Company calculates NPC.

A. NPC are calculated using the Generation and Regulation Initiative Decision model ("GRID"). GRID is a production cost model that simulates the operation of the Company's power system on an hourly basis.

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

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

Q. Is the Company using the same version of the GRID model as used in Case No. PAC-E-08-07?

A. Yes.

Q. What inputs were updated for this filing?

A. The system load, wholesale sales and purchase contracts for electricity, natural gas and wheeling, market prices for electricity and natural gas, fuel expenses, characteristics of the Company's generation facilities, planned outages and forced outages of the Company's generation resources are updated for this filing.

Q. Was the transmission topology also updated for this filing?

A. Yes. The transfer capabilities of the transmission paths have been updated. In addition, as I mentioned above, the transfer capability of Path C to Utah has reflected the impact of the transmission line from Populus to Terminal.

Q. What reports does the GRID model produce?

A. The major output from the GRID model is the NPC report. This is attached to my testimony as confidential Exhibit No. 40. Additional data with more detailed analyses are also available in hourly, daily, monthly and annual formats by heavy-load hours and light-load hours.

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

A. No. As in the 2008 general rate case, the normalized hydro generation is produced by the Vista model, except the enhancement that I will discuss later in my testimony.

Q. Are the inputs to Vista prepared in the same way as in the Company's 2008 general rate case?

A. The historical information used as the basis of the normalized generation continues to include all available years, except for the Bear River system. The Bear River system data excludes flood control years, which is an unlikely event. The Company is, however, currently in the process of reviewing patterns of weather and stream flow changes for hydro generation in the context of changes in climate, both globally and in the region. Based on this review, the Company may propose changes to its modeling of normalized hydro generation in future proceedings.

Q. Do you believe that the GRID model appropriately reflects the Company's system operations in its operating environment?

A. Yes. The use of the GRID model as described in my testimony reasonably simulates the operation of the Company's system consistent with the Company's operation of the system, including operating constraints and requirements.

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

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

Enhancements to the Hydro Modeling

Q. Please describe the enhancements to the hydro inputs the Company made in the filing.

A. There are two enhancements to the hydro inputs of the GRID model. The first enhancement is to apply single-year median hydro generation. The second enhancement is to explicitly model the reduced generation related to operating the hydro units for reserve purposes that causes "motoring" and efficiency losses.

Q. How has the Company changed its hydro generation inputs for normalized net power costs?

A. In its 2008 general rate case, the Company used three equally weighted "exceedence levels" of hydro generation to determine the hydro volumes used in GRID and the dispatch of the other resources. In the current filing, the Company uses the single-year median hydro condition.

Q. Why does the Company choose to use the single-year median hydro?

A. It is transparent and easy to understand and it is consistent with the hydro condition used by the Company for operational planning.

Q. What is a "single-year median?"

A. The single-year median hydro generation that the Company uses as the input to GRID in the current proceeding has one year normalized output from the Vista model, which is the same model that the Company utilized in the prior filings to produce normalized hydro generation of the Company's hydro projects. The inputs to Vista include median inflow volumes of the hydro projects from the available water inflow history. The inflow volumes are pro-rated daily or weekly based on weighting factors derived from corresponding median inflows. The annual volume of stream flows are based on a single year, hence the "single-year" reference.

Q. Please describe how the median hydro forecast is created.

A. For run-of-river projects, the single-year forecast is simply the median generation of the available historical data. For other river systems with reservoirs and the Mid-Columbia projects, the single-year inflow forecast is created based on the average daily or weekly shape and median annual volume of the available historical inflow data, which can range from about 40 years to about 90 years depending on the river system.

Q. Please explain the reduction in hydro generation due to motoring for spinning reserves.

A. In order to meet spinning reserve requirements, the Company must keep generating resources connected to the transmission grid and be responsive to automatic generation control. One option for providing spinning reserves is to "motor" a unit which means the unit is connected to the grid and spinning with electrical energy rather than with water. At the Swift plant, the normal amount of energy required to motor a unit is about two megawatts. Motoring the unit with two megawatts of energy provides spinning reserve for the full range of unit output. To spin the unit at minimum load with water would require a flow through the turbine of about 350 cubic feet per second, which is extremely inefficient and would consume the equivalent of about 10 megawatts. Even though motoring consumes energy, it is more efficient and cost-effective than spinning a unit with water.

Q. What are the efficiency losses the Company proposes to capture in its hydro modeling?

A. To provide load following and system regulating requirements, the dispatchable hydro units at the Swift and Yale plants from time to time operate significantly below peak efficiency. However, the forecasted hydro generation data from the Vista model is optimized at peak efficiency. The cumulative effect of load following with hydro units is less efficient operations. In other words, less energy is generated with the same amount of water than would have been generated at peak efficiency.

Q. How does the Company adjust for the lost generation?

A. The lost generation from the Company's Lewis River is deducted from its optimized generation. The amount of the adjustment is based on 2009 historical information.

Wind Integration Charges

Q. What has the Company included for wind integration charges in this filing?

A. As discussed previously, the Company used $6.50 per megawatt-hour as the rate of the wind integration charge for the wind generation located in its control areas. This rate has been authorized by the Commission in Case No. PAC-E-09-07 for the purpose of setting avoided costs. For the two wind projects located in the BPA's control area, Leaning Juniper and Goodnoe Hills, the wind integration charge is based on BPA's tariff rate at $1.29 per kW-month beginning in October 2009 for variations in the wind generation within 30 minutes. This charge is approximately $5.89 per megawatt-hour based on a 30 percent capacity factor for the wind resource.

Q. Has the Company updated its wind integration charge since its last general rate case?

A. Yes. As part of its 2008 IRP filed with the Commission on May 29, 2009, the Company performed studies on the impact of integrating the generation from the wind projects into its system.

Q. Why doesn't the Company use the wind integration costs from its 2008 IRP?

A. To minimize controversy, the Company uses the same wind integration charge that has been approved by the Commission for setting avoided costs in Idaho. In addition, the Company is in the process of updating the wind integration study as part of its 2011 IRP.

Conclusion

Q. Is the normalized system-wide net power costs for the 12-month period ending December 2010 reflective of costs that the Company will incur on behalf of its customers and should it be included in rates?

A. Yes. The Company's normalized net power costs in the amount of $1.07 billion on a total Company basis, and $69.2 million allocated to Idaho is what the Company expects to incur on behalf of its customers. This level of NPC, as updated by the ECAM, is in the public interest and should be included in Idaho rates for recovery by the Company.

Q. Does this conclude your direct testimony?

A. Yes.

CONFIDENTIAL
Case No. PAC-E-10-07
Exhibit No. 40
Witness: Hui Shu

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

ROCKY MOUNTAIN POWER

CONFIDENTIAL
Exhibit Accompanying Direct Testimony of Hui Shu

NPC Report

May 2010

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