Rocky Mountain Power
Docket No. 13-035-184
Witness: Gregory N. Duvall

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

REDACTED
Direct Testimony of Gregory N. Duvall

Net Power Costs

January 2014

Q. Please state your name, business address and present position with PacifiCorp dba Rocky Mountain Power ("the Company").

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

Qualifications

Q. Briefly describe your education and business experience.

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

Purpose of Testimony

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

A. I present the Company's proposed net power costs ("NPC") for the 12-month test period ending June 30, 2015. Specifically, my testimony:

- Explains the calculation of NPC using the Company's Generation and Regulation Initiative Decision model ("GRID") model;

- Describes the primary drivers behind the increase in NPC compared to NPC included in the stipulation approved in the Company's previous general rate case, Docket No. 11-035-200 ("2012 GRC");
- Describes changes the Company has made to the NPC study since the 2012 GRC, including updates to the Company's resource portfolio as well as improvements to the modeling of NPC;
- Discusses the Company's proposed treatment of its participation in an energy imbalance market ("EIM") with the California Independent System Operator ("CAISO"); and
- Proposes a process to update NPC during the course of this proceeding to improve the accuracy of the Base NPC for energy balancing account ("EBA") filings while accommodating the needs of other parties to review and validate the NPC updates.

Summary of Net Power Costs

Q. Please explain the components making up NPC.

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

Q. What are the proposed system-wide NPC for the 12-month period ending June 2015?

A. The proposed NPC for the 12 months ending June 30, 2015, are $1.522 billion on a total Company basis, and $641.1 million on a Utah-allocated basis. The proposed NPC are approximately $5.1 million (0.8 percent) higher than the 2012 GRC on a Utah-allocated basis.

Determination of NPC and GRID Model Inputs and Outputs

Q. Please explain how the Company calculates NPC.

A. NPC are calculated for a future test period based on projected data using GRID, 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 has used the GRID model to determine NPC in its Utah filings for several years.

Q. Is the Company using the same version of the GRID model as used in its 2012 GRC?

A. Yes.

Q. What inputs were updated for this filing?

A. All inputs have been updated since the 2012 GRC, including system load, wholesale sales and purchase contracts for electricity, natural gas and wheeling, market prices for electricity and natural gas, fuel expenses, and the characteristics and availability of the Company's generation facilities. The transmission areas within the GRID model topology are unchanged since the 2012 GRC, but the transmission capacity between areas has been updated to reflect the Company's transfer rights for the test period.

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 Exhibit RMP___(GND-1). The GRID model also produces more detailed reports in hourly, daily, monthly and annual formats by heavy-load hours ("HLH") and light-load hours ("LLH").

Q. Please generally describe the changes in NPC compared to the 2012 GRC.

A. Table 1 below illustrates the change in NPC by category compared to the NPC approved in the 2012 GRC.

Table 1
Net Power Cost Reconciliation ($millions)

	Total Company	**Utah Allocated**
2012 General Rate Case	**$1,479.2**	**$636.0**
Increase/(Decrease) to NPC		
Wholesale Sales Revenue	$106.2	$47.7
Purchased Power Expense	$(85.7)	$(41.0)
Coal Fuel Expense	$88.3	$29.8
Natural Gas Fuel Expense	$(76.7)	$(36.0)
Wheeling, Hydro and Other Expense	$10.6	$4.5
Total Increase/(Decrease) to NPC	**$42.7**	**$5.1**
2014 General Rate Case	**$1,521.9**	**$641.1**

As shown in Table 1, while total-Company NPC are $43 million (2.9 percent) higher, on a Utah-allocated basis NPC in this case are only $5 million (0.8 percent) higher than in the 2012 GRC. As described in the testimony of Company witness Ms. Kelcey A. Brown, total system load remained relatively flat compared to the 2012 GRC, but Utah jurisdictional load is lower than in the 2012 GRC, resulting in a lower percentage allocation of NPC using the dynamic load-based allocation factors. Unless otherwise noted, references to net power costs or various individual cost items are stated in Utah-allocated amounts.

On a Utah-allocated basis, the increase in NPC is the result of a decrease in wholesale sales revenue of $48 million, an increase in coal fuel expense of $30 million, and an increase in wheeling and other expenses of $5 million. These increases are partially offset by a decrease in purchased power expense of $41 million, and a decrease in natural gas fuel expense of $36 million.

Q. Did you calculate the impact to NPC if Naughton Unit 3 is not converted to gas during the test period?

A. Yes. As described in the direct testimony of Company witnesses Mr. Steven R. McDougal and Mr. Chad A. Teply, the Company's filing is based on the assumption that the Company will discontinue coal-fired generation at Naughton Unit 3 at the end of 2014 and convert it to a gas-fired resource that will return to operation in June 2015. A second NPC study has been prepared which incorporates the assumption that coal-fired operation at Naughton Unit 3 continues through the test period. The revenue requirement impact of continuing coal-fired generation is described in Mr. McDougal's direct testimony. Unless otherwise indicated, the NPC results described in my testimony refer to the scenario that assumes Naughton Unit 3 is converted to gas generation during the test period.

Discussion of Major Cost Drivers in NPC

Q. Please explain the reduction in wholesale sales revenue.

A. The reduction in wholesale sales revenue is driven by the expiration of four long-term sales contracts and reduced revenue from wholesale market sales. The 2012 GRC included approximately $9.9 million from long-term sales to Nevada and

California utilities that expired at the end of 2012. In addition, the long term sale to the Sacramento Municipal Utility District ("SMUD") expires at the end of 2014 and is only included for six months in the current GRC, reducing wholesale sales revenue by approximately $1.5 million.

Revenue from market transactions (represented in GRID as short-term firm and system balancing sales) is approximately $35.0 million lower than in the 2012 GRC. The drop in revenue is due mainly to reduced volume of forward market sales, partially offset by a rise in wholesale market prices. Market sales transactions in the 2012 GRC were included at an average price of $32.44/MWh, while market sales in the current case are included at an average price of $33.62/MWh.

Q. Has the Company also seen a decrease in purchased power expense?

A. Yes. Similar to wholesale sales, the reduction in purchased power expense is driven by the expiration of several long-term purchase contracts and reduced expenses related to wholesale market purchases. The 2012 GRC included approximately $6.1 million for the West Valley tolling agreement, Kennecott generation incentive, Grant County 10 aMW purchase, and Cargill exchange, all of which have now expired. In addition, three large qualifying facilities ("QFs") that were previously included are not expected to provide generation in the test period, reducing purchased power expense approximately $5.7 million. The reduction in long-term purchased power expense is partially offset by additional expenses related to a new seasonal purchase contract and purchases from QFs. Further details regarding the changes in contracts are provided later in my testimony.

Expenses from market transactions (represented in GRID as short-term firm and system balancing purchases) are approximately $37.4 million lower than in the 2012 GRC. The drop in expense is due mainly to reduced volume of forward market purchases, partially offset by the impact of higher wholesale market prices. Market purchase transactions in the 2012 GRC were included at an average price of $27.13/MWh, while market purchases in the current case are included at an average price of $28.44/MWh.

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

A. The increase in coal fuel expense is driven by higher prices for coal during the Test Period. Price increases are reflected in both the costs of third-party coal supply and cost increases at the Company's captive mines. Details on coal price changes are provided in the direct testimony of Company witness Ms. Cindy A. Crane.

Generation output from the Company's coal-fired thermal plants is higher than in the 2012 GRC, despite the conversion of Naughton Unit 3 to gas in 2015 and the retirement of the Carbon plant in April 2015. Due to the termination of coal-fired operation at Naughton Unit 3 in December 2014, generation at the Naughton plant is lower than the 2012 GRC by approximately 1,225 GWh. The removal of the Carbon units from service in April 2015 causes generation at that plant to be approximately 137 GWh lower than the 2012 GRC. Excluding these reductions, the Company coal generation is approximately 1,600 GWh higher than the 2012 GRC. This increase in generation output reflects the increase in market prices since the prior test period, as there are more periods in which coal generation is more economic than market purchases.

Q. Please discuss the drop in natural gas fuel expense since the 2012 GRC.

A. The reduction in natural gas fuel expense is driven by lower generation volume and a lower average cost of natural gas. The Company's gas generation declined by 688 GWh, primarily due to the removal of the "must run" requirements for the Currant Creek plant and the Gadsby combustion turbines, partially offset by the addition of the Lake Side 2 plant. The average cost of natural gas generation decreased from $40.99 per MWh in the 2012 GRC to $35.38 per MWh in the current case.

Q. Please describe the increase in the wheeling, hydro, and other expense category.

A. Expenses in this category are higher due to an increase in wheeling expense resulting from the Bonneville Power Administration ("BPA") 2014 Wholesale Power and Transmission Rate Adjustment Proceeding. Effective October 2013, the Company's wheeling expenses paid to BPA increased by approximately 13 percent.

Changes to the Company's Resource Portfolio

Q. Have changes been made to the modeling of the Company's resources since the 2012 GRC?

A. Yes. The Company's modeling incorporates a number of resource changes to account for operational differences between the 2012 GRC and the end of the test period in this case.

- *Lake Side 2* - The Lake Side 2 plant is expected to begin commercial operation by June 2014, prior to the start of the test period.
- *Carbon Termination* - The Carbon plant is expected to terminate in April 2015.
- *Naughton 3 Gas Conversion* - Naughton Unit 3 is expected to be removed from service as a coal plant in January 2015 and returned to service as a gas plant in June 2015.
- *Chehalis Reserves* - Transmission system upgrades necessary to dynamically transfer the Chehalis plant into the Company's PACW balancing authority area were completed in November 2013. As a result, the Chehalis plant is now modeled with reserve-carrying capability throughout the test period, reducing the need for holding reserves on lower cost resources in the Company's west balancing authority area ("PACW"), such as the Jim Bridger plant. In previous cases it was suggested that the Chehalis plant should be modeled with reserve-carrying capability, but at that time, it was not possible for the Company to carry reserves with this plant.
- *Goodnoe Hills and Leaning Juniper Balancing Area Transfer* - Transmission system upgrades necessary to dynamically transfer the Goodnoe Hills and Leaning Juniper plants into the Company's PACW balancing authority area were completed in April 2013. As a result the Company now provides the regulation and contingency reserves for these plants rather than purchasing them from BPA. The regulation cost was previously included in wheeling

expense. The contingency reserve expense was previously included in the purchase power section of NPC under the label "BPA Reserve Purchase".

- *Leaning Juniper Output and Revenue* - The Company will receive a small amount of revenue associated with the Company's Leaning Juniper facility due to a contract unique to that wind project. As a result of the contract, output at Leaning Juniper is forecast at a slightly reduced level. A confidential copy of the executed contract is provided as part of the filing requirements accompanying the Company's case and a confidential summary of the contract is provided with the testimony of Ms. Stacey J. Kusters as Confidential Exhibit RMP___(SJK-6).
- *St. Anthony Hydro* - The St. Anthony hydro facility in Idaho had been out of service for a number of years and selling the facility was determined to be the most cost-effective path forward. The sale was recently completed, and following the completion of repairs, the new owner will operate the plant as a QF and sell the output to the Company. The project is expected to reach commercial operation prior to the start of the test period.
- *Thermal Upgrades/Environmental Controls* - Environmental upgrades at the Hunter and Hayden plants will reduce plant capacity at Hunter 1 in May 2014 and at Hayden 1 in May 2015. Further details on these capital projects are provided in the direct testimony of Company witness Chad A. Teply.

In addition to the specific changes listed above, the Company has updated the operating characteristics of its generation fleet and incorporated historical operating data through the base period of June 2013.

Q. Have there been changes to the Company's long-term purchase and sale contracts since the 2012 GRC?

A. Yes. As described earlier, several long-term purchase and sale contracts that were included in the 2012 GRC have been terminated or will expire by the end of the test period in this case, including:

- The long-term sales agreement with SMUD expires December 2014.
- Three sales agreements providing energy and renewable energy credits to Pacific Gas & Electric, Southern California Edison, and Nevada Energy expired December 2012.
- A 10-average megawatt purchase from Grant County Public Utility District expired August 2012.
- A tolling agreement for the output of the West Valley generating station expired December 2013.
- The Pioneer Wind Park II QF contract was terminated due to failure to achieve commercial operation.
- Existing QF contracts with US Magnesium and SF Phosphates expired December 2012 and December 2013, respectively. Under the previous agreements these customers sold their QF output to the Company as a buy-all, sell-all arrangement, but going forward they are expected to use the generation to first offset retail load.
- Exchange agreements with Shell and Cargill which provided power deliveries close to the Company's loads during the summer peak terminated in September 2012 and September 2013, respectively.

- Exchange agreements with BPA and Public Service Company of Colorado ("PSCo") for integration and delivery of the output of Foote Creek II and III will expire in July 2014 and September 2014, respectively.
- The Kennecott Generation Incentive agreement terminated in December 2012.

The Company has also entered into several new long-term purchase and sale agreements, including:

- A 13 month sale to Shell with deliveries through August 2014. This contract included an option for the Company to extend deliveries through the end of 2014.
- A seasonal purchase from Constellation for 2013 through 2016, which helps ensure the Company will have sufficient resources to meet peak requirements.
- A QF contract with Latigo Wind Park for a new wind facility in Utah.
- A QF contract with OM Power I for a new geothermal facility in Oregon.
- Various other small QF contracts, including four new solar facilities in Utah receiving Schedule 37 prices.

Q. Did the Company extend any contracts in its NPC study that are scheduled to expire during the Test Period?

A. Yes. Several existing QF contracts terminate prior to the end of the Test Period and the Company has assumed that these customers will enter contracts to continue selling to the Company at the most recent avoided cost rates. In addition, the Company assumed the existing contract with US Magnesium for operating reserves would be renewed after it expires in December 2014. The Company anticipates updating NPC in this proceeding as more information becomes available.

Q. Does this case include the natural gas contracts executed as a result of the Company's 2012 Natural Gas Request for Proposals?

A. Yes. The Company has entered into two gas swap transactions as a result of the Company's 2012 Natural Gas Request for Proposals ("2012 Gas RFP"). The 2012 Gas RFP was filed with the Utah Public Service Commission ("Commission") in Docket No. 12-035-102. On April 19, 2013, the Commission issued an order approving a stipulation recommending pre-approval of the long-term natural gas contract with pricing that yields a market ratio[1] at or below 100 percent and meets explicit price parameters.[2]

Q. Please outline the material provisions of the stipulation relating to transactions from the 2012 Gas RFP.

A. Under the stipulation, the parties agreed that the Company would seek to secure [redacted] whichever is priced more favorably to market. [redacted] The Company agreed to execute only if the transaction: (1) meets the Company's internal credit quality requirements; and (2) has refreshed pricing that yields a market ratio below 100 percent calculated from the Company's forward price

[1]A market ratio is a cost-to-value ratio, in which "cost" is the numerator and "value" is the dominator. The "cost" is the bid price. The market "value" of a bid is assessed as a part of the RFP bid evaluation process. Both "cost" and "value" are levelized over the term of the bid in the equation. A lower market ratio reflects a more attractive product. The market ratio provides a comparison between bids with different terms, location of natural gas supply, delivery, settlement, and product type.

[2]*In the Matter of the Voluntary Request of Rocky Mountain Power for Approval of Resource Decision to Acquire Natural Gas Resources*, Docket No. 12-035-102, Report and Order (April 19, 2013).

curve. The stipulation also dictated a pricing structure with prices for the first two years aligned with current market prices [redacted] In August 2013 the Company executed two [redacted] contracts with J. Aron for a total volume of [redacted]. Both contracts met the price parameters and market ratio specified in the stipulation. Confidential copies of the executed contracts are provided as part of the filing requirements accompanying the Company's case.

GRID Modeling Improvements

Q. Has the Company modified its modeling to address any contested issues from the 2012 GRC?

A. Yes. In response to issues raised by parties in the Company's 2012 GRC, the Company refined the following inputs to GRID:

- *Market Capacity* - Sales restrictions on the Mid-Columbia and Palo Verde markets have been removed. The remaining markets continue to be limited by caps on wholesale sales based on the four-year average historical short term firm transactions, broken down by market, month and hour class. The Company's market capacity methodology is discussed in further detail later in my testimony.
- *"Must Run" Gas Plant Operation* - The 2012 Wind Study did not have resource-specific reserve requirements for Currant Creek and the Gadsby combustion turbines so these plants are now dispatched based on economics, rather than forced online to provide reserves. The 2012 Wind Study and its impact on integration costs in this case are discussed later in my testimony.

- *Chehalis Reserves* - As mentioned previously, the transmission system upgrades necessary to dynamically transfer the Chehalis plant into PACW were completed in November 2013. As a result, the Chehalis plant is now modeled with reserve-carrying capability throughout the test period.
- *Hydro Forced Outage Rates* - In the current case, the availability of hydro units with storage capability has been normalized to reflect forced outage levels by making a flat percentage reduction in capacity across all hours of the period, a method similar to that used for thermal units. The reductions to plant capacity are based on the outages from the same 48-month historical period used for thermal plants in this case. An additional adjustment to reflect energy lost due to forced outages is made to hydro generation based on historical measurements which began in January 2011. Adjusting for lost energy based on historical measurements captures the flexibility of hydro projects with storage capability to shift generation around outages, while accounting for the operating constraints that may prevent such shifts under certain circumstances.

In past cases parties have also challenged the costs related to the DC Intertie transmission contract between the Company and BPA. The Company continues to include the DC Intertie rights in the GRID model, along with the annual wheeling expense. Later in my testimony I provide additional evidence supporting the continued inclusion of this contract in customers' rates.

Q. Has the Company made any changes to improve the accuracy of its NPC modeling?

A. Yes. The Company has made various updates to the GRID inputs in order to increase the accuracy of the forecasted NPC, including:

- *Wind Generation Shape* - In previous proceedings, wind generation has been based on a P50 forecast, a projection of generation developed through third-party analysis that is expected to have an equal probability of being higher or lower than actual output over time. For modeling purposes in past cases the Company divided the generation into six four-hour blocks per day for each month. All of the hours within a given four-hour block in a month had the same expected energy, creating a flat profile in GRID with very little variation. In this case, the Company has employed a wind shaping methodology that scales actual generation data into an hourly shape that retains the overall energy from the P50 generation estimate. Further details on the wind shaping methodology and how it improves the accuracy of NPC modeling are provided later in my testimony.
- *Integration Costs* - The Company's wind integration costs are now based on the 2012 Wind Study released in April 2013 as Appendix H to the Company's 2013 Integrated Resource Plan.[3] The 2012 Wind Study indicates that the estimated cost of wind integration has declined, primarily because of lower forecast natural gas and power market prices. Further details regarding integration costs in the test period are provided later in my testimony.
- *CAISO Fees* - Since January 1, 2013, when California's carbon cap and trade program took effect, electricity imported into California results in a carbon emissions allowance obligation. As a result, the Company has not sold power

[3] www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2013IRP/PacifiCorp-2013IRP_Vol2-Appendices_4-30-13.pdf.

to the CAISO since that time. Previously, the Company included CAISO sales volumes and wheeling expense based on the 12-month historical period. To align with the recent change in operating practice, the sales volumes and associated wheeling expense have been removed from the test period in this case.

GRID Modeling Improvements - Market Capacity

Q. Please explain why the Company specifies market capacity limits, a.k.a. market caps, in GRID.

A. The GRID model automatically assumes unlimited market depth bound only by the Company's transmission constraints for system balancing sales and purchases; it does not account for load requirements or market illiquidity that would not allow the Company to make sales at a static forecast market price. The Company's transmission access to a market point limits its ability to sell its generation in that market; similarly, counterparties' demand for purchases is limited by their transmission access and their own load and resource balance. Without market caps, the GRID model has no constraints to reflect counterparties' inability to make economic transactions. While market caps have been an input to GRID since its inception, the current method for calculating the caps was put in place in the Company's 2010 general rate case, Docket No. 10-035-124. In the current case, the Company has removed the market caps from the Mid-Columbia and Palo Verde markets.

Q. How are the market caps calculated?

A. For each market, the allowable level of wholesale sales is specified for all hours based on a four-year historical average of both spot and short-term firm wholesale sales transactions, aggregated by month and HLH/LLH periods. In this case the four-year historical average has been updated to the period ending June 2013.

Q. Please further explain the static assumptions of market prices in GRID.

A. The Company's official forward price curve ("OFPC") produces an hourly price that remains static in GRID in each hour, regardless of the changes in load and resource balance. The driving force behind market prices in real-time is based on the dispatch cost of additional generation; therefore, an increase in load or reduction in resources will require that higher cost resources be dispatched, or vice versa. In reality, prices are impacted by changes in the loads and resources of all market participants, including the Company. Without market caps the GRID model will overestimate sales revenues as it continues to make sales at the static hourly market price, even though additional sales would push market prices down.

Q. Why has the Company removed the market caps from the Mid-Columbia and Palo Verde markets?

A. Market caps have been challenged in the past several general rate cases where parties have argued to remove all market caps. The Company proposes to remove market caps at Mid-Columbia and Palo Verde as a compromise position since these two markets are the most liquid market points to which the Company has access. These markets both have many participants and are often used to balance the Company's load and resource position on a forward basis. This is not the case with the other market hub in GRID. As a result, the Company's historical sales at these markets may be more strongly aligned with the Company's resource position, rather than the position of the other counterparties in the market, as would be the case in the less liquid markets.

Furthermore, the short-term firm sales volume upon which market caps are based has been declining over time which has lowered the market caps. In past cases, the caps at the Mid-Columbia and Palo Verde markets exceeded the transmission capability and forward transaction position at these markets in all hours and had no impact on the model outcome. With the updated historical volume, the caps at these two markets would be lower than the transmission capability and forward transaction position and would restrict the GRID model's ability to transact at these two most liquid markets, counter to operational reality.

With the caps on Mid-Columbia and Palo Verde removed, the GRID model has more flexibility to sell in these markets, better reflecting the Company's actual operating potential.

Q. Did the Company change the calculation of the market caps for the remaining four markets modeled in GRID?

A. No. The market caps remain intact for the COB, Four Corners, Mona, and Mead markets. These markets are less liquid and the GRID model must continue to have constraints on the transactions that can occur at these markets. As discussed above, GRID will assume unlimited market depth if market caps are not in place.

GRID Modeling Improvements - Wind Generation Shape

Q. Please explain how the Company models wind generation in GRID.

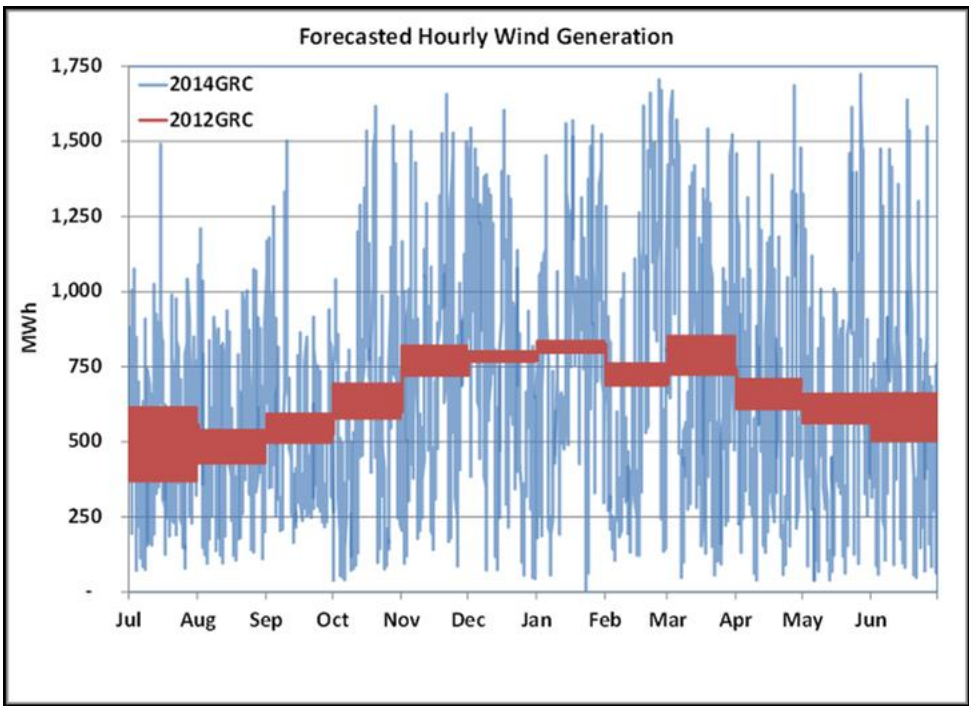
A. Total energy from wind generation is included in GRID based on a "P50" forecast. A P50 forecast projects generation at a level that is expected to have an equal probability of being higher or lower than actual output. Typically such a forecast is developed by a third party for an individual wind project by combining wind speed measurements taken prior to the project being constructed with a detailed model of turbine locations and performance characteristics. The projected output in a given hour is then averaged across each month to develop a 12 month by 24 hour matrix of average hourly output. The Company previously input wind generation into GRID using the P50 forecast divided into six four-hour blocks per day. Generation was flat over each four-hour block, and each period was the same for every day during a month. Consequently, the wind generation in GRID exhibited very little variation which is not consistent with operational reality.

In this case, the Company continued to use the P50 forecast to determine total wind generation, but utilized the actual 2012 energy output data from the Company's owned and purchased wind facilities to shape hourly wind generation profiles. The Company scaled actual generation levels up or down so that, when the output within the traditional four-hour blocks is averaged over the course of a month, it is the same as in the P50 forecast. In other words, the total energy output of the wind facilities is the same as the P50 forecast energy output used in previous cases, but the shape of the generation varies on an hourly basis consistent with actual output during 2012.

Q. Why did the Company refine the modeling of its hourly wind profiles to reflect historical performance?

A. The Company refined its modeling to improve the accuracy of its NPC forecast, using the most recent reliable data available to develop wind profiles that capture the volatility of wind generation in forecast NPC. Figure 1 below illustrates the difference in the two approaches to developing wind generation profiles. The darker line with smooth step changes represents the previous wind inputs using four-hour blocks. The highly variable line represents the wind inputs that vary hourly based on historical volatility, with the same total wind generation volume as the P50 forecast.

Figure 1



Clearly, an average wind generation forecast shaped over flat four-hour blocks does not capture the actual variability associated with wind generation on the Company's system. Applying the 2012 actual wind generation pattern to the total P50 volumes improves the accuracy of forecasted NPC by capturing more of the cost impacts associated with intermittent wind generation on an hourly basis using the most recent data available.

Q. Why did the Company use a single year, in this case 2012, to derive an hourly shape for wind energy?

A. The Company used 2012 data because it represents the most recent calendar year data available at the time of the filing. The use of prior periods would prevent consistent hourly shaping across the Company's wind portfolio, as projects that came online more recently would not have data available from earlier periods.

Q. Is there evidence that the Company's wind shaping methodology based on a single year is appropriate?

A. Yes. A technical report published by the National Renewable Energy Laboratory ("NREL")[4] examined the variability in wind generation over various lengths of time. The report found that "one can expect relatively large inter-annual changes", but "for even shorter-term variations, such as power level from one hour to the next, changes of wind power levels become a stochastic process with a very narrow range of standard deviation values around its respective mean… when those mean and standard deviation values are expressed in terms of the installed capacity of the WPPs[5], they are almost constant on an annual basis… It can be concluded that short-term wind power fluctuations do not exhibit year-to-year variability."[6]

Q. What does this mean with regard to the Company's wind shaping methodology?

A. The Company's methodology ensures that average monthly energy output in each

[4]*Long-Term Wind Power Variability*. Y. H. Wan. Technical Report, NREL/TP-5500-53637. Retrieved online at http://www.nrel.gov/docs/fy12osti/53637.pdf.
[5]WPP is an acronym for Wind Power Plant as by NREL.
[6]*Id.*

four-hour block remains at the P50 forecast, so it will not result in inter-annual changes in output. Because short-term wind power fluctuations are not expected to vary significantly from year to year, the use of the most recent year will not have significant differences in variability compared to other years.

Q. Has the Company prepared an analysis of the variability of its wind plants similar to the analysis presented in the NREL report?

A. Yes. In its study, NREL calculated the coefficient of variation ("COV"), defined as the ratio of standard deviation value to plant nameplate capacity, to gauge the short-term variability of wind generation. The Company applied this same calculation on four of its own wind resources. Table 2 below shows that the COV of the Foote Creek, Wolverine Creek, Goodnoe Hills, and Leaning Juniper wind plants is fairly consistent over time. It also shows that the variability in the Company's revised modeling is much closer to the historical levels.

Table 2
Yearly COV Value of Yearly Wind Power
(Normalized to Plant Name Plate Capacity)

Year	Leaning Juniper	Goodnoe Hills	Wolverine Creek	Foote Creek 1
2001				0.28
2002				0.26
2003				0.32
2004				0.33
2005				0.33
2006				0.33
2007			0.27	0.30
2008	0.36		0.30	0.30
2009	0.35	0.32	0.29	0.23
2010	0.32	0.29	0.29	0.24
2011	0.31	0.30	0.32	0.31
2012	0.28	0.30	0.31	0.27
Average	0.32	0.30	0.30	0.29
Previous Methodology	0.11	0.11	0.08	0.13
Revised Methodology	0.27	0.29	0.28	0.27

GRID Modeling Improvements - Integration Costs

Q. Has the Company updated its modeling of wind integration costs?

A. Yes. The Company's wind integration costs are now based on the 2012 Wind Study released in April 2013 as Appendix H to the Company's 2013 Integrated Resource Plan. The 2012 Wind Study is the result of an extensive public process that received guidance from a Technical Review Committee that included numerous subject-matter experts. The 2012 Wind Study indicates that the estimated cost of wind integration has declined, primarily because of lower forecast natural gas and power market prices.

Q. How has the modeling of wind integration changed as a result of the 2012 Wind Study?

A. There are three modeling changes compared with the 2012 GRC:

- The reserve requirements included in the GRID model have been updated reflect the results of the 2012 Wind Study, with adjustments to integrate all additional wind capacity that will be online during the test period, including the Leaning Juniper and Goodnoe Hills plants that will be transferred to PACW.
- The "must run" settings for Currant Creek and the Gadsby combustion turbines have been removed and these plants are dispatched based on economics.
- The inter-hour integration costs for load and wind have been updated.

Q. What level of reserves is included in the current case as a result of the 2012 Wind Study?

A. The 2012 Wind Study concludes that an average of 579 MW of reserves were necessary on the Company's system in calendar year 2011 to integrate load and 2,126 MW of wind capacity. This case includes an average of 616 MW of regulating reserves to integrate load and 2,563 MW of wind capacity.

Q. What are the resulting integration costs included in NPC?

A. The cost of integrating wind generation in the test period is approximately \$2.03/MWh. In the 2012 GRC the cost of integrating wind generation was approximately \$3.44/MWh.

Q. Why have wind integration costs declined since the prior case?

A. Four factors contribute to lower wind integration costs in the test period. First, the inter-hour wind integration expense in the 2012 Wind Study is lower than in the 2010 Wind Study. Second, the removal of the "must run" settings for Currant

Creek and the Gadsby combustion turbines allows other units to provide generation and/or reserves at lower cost. Third, the addition of the Lake Side 2 plant increases the reserve holding capability of the Company's fleet and holds reserves that would otherwise be held on lower cost resources. Finally, the regulating reserve requirement for a given quantity of wind is lower in the 2012 Wind Study compared to the 2010 Wind Study. The prior rate case had 9.6 MW of regulating reserves for each 100 MW of wind capacity, while the current case has 8.3 MW of regulating reserves for each 100 MW of wind capacity.

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

A. Yes. The Company is required by federal law to provide wind integration services to its wholesale customers on a non-discriminatory basis. Therefore, the Company continues to believe it is appropriate to reflect these costs in rates as prudent and necessary costs associated with operating its system.

Q. Does the Company's case include the revenues associated with integrating the non-owned wind generation in the Company's balancing authority areas?

A. Yes. Schedules 3 and 3A of PacifiCorp Transmission's Open Access Transmission Tariff ("OATT") specify the rates for Regulation and Frequency Response Service for network customers and generators that transfer their output off-system, respectively. These OATT revenues are not part of NPC, but are credited against the revenue requirement as wheeling revenue. This revenue is also a component of the EBA costs that are trued-up in the annual EBA filings.

Q. Does this case include costs for integrating solar resources in the Company's balancing authority areas?

A. Yes. In Docket No. 12-035-100[7] the Commission recently determined that the cost of integrating solar resources should be set at a certain portion of wind integration costs until the Company performs a solar integration study. Per the Commission's order, solar integration costs are set at $2.18/MWh for tracking solar resources, and $2.83/MWh for fixed solar resources. In this case the Company applied these costs to the generation from five small solar QFs, located in Utah, which will be online during the test period.

GRID Modeling Improvements - DC Intertie

Q. Please provide background on the DC Intertie contract.

A. In anticipation of the expansion of the Alternating Current ("AC") Intertie to 4,800 MW, PacifiCorp and the Bonneville Power Administration ("BPA") reached a settlement of outstanding issues about the right to use the AC and DC Interties and the Midpoint-Medford transmission line. The settlement was documented in a Letter of Understanding ("LOU") which was executed on May 28, 1993. A copy of the LOU is provided as Exhibit RMP___(GND-2).[8] As a result of the LOU, PacifiCorp received 400 MW of bidirectional rights on the AC Intertie, priority rights to an additional 125 MW of southbound transmission, four additional delivery points to the AC Intertie, and 200 MW of northbound rights on the DC Intertie. BPA received rights to up to 400 MW of eastbound transmission

[7] *In the Matter of the Application of Rocky Mountain Power for Approval of Changes to Renewable Avoided Cost Methodology for Qualifying Facilities Projects Larger than Three Megawatts*, Docket No. 12-035-100, Report and Order (August 16, 2013).

[8] Although the LOU is marked "Confidential," the Company is not asserting that this document is confidential in this docket.

on PacifiCorp's Summer Lake-Midpoint line, rights to certain PacifiCorp transmission, and the option to take energy under spring and summer exchanges. The agreement states that the DC Intertie contract term will be equal to the term of the AC Intertie agreement, and that the AC Intertie agreement is extended for the life of the facilities it covers. These rights are functionally equivalent to ownership. Consistent with the LOU, the DC Intertie contract was executed on May 26, 1994.

Q. Why is this background important?

A. It is important because under the LOU, BPA and PacifiCorp agreed that the provisions of the LOU are interdependent and not severable. In other words, an analysis of the DC Intertie cannot be conducted without addressing all of the other rights and obligations PacifiCorp signed up to in the LOU.

Q. What benefits do customers receive from the DC Intertie?

A. The DC Intertie is a valuable transmission asset to the Company and its customers. The contract provides a means to secure capacity and energy from California sources in order to reliably meet retail loads. The transmission rights take advantage of the load diversity between summer-peaking California and the winter-peaking Pacific Northwest and represent an integral piece of the transmission network for maintaining reliability in PACW. The DC Intertie contract is the only PacifiCorp contract that provides firm import rights from the Nevada-Oregon Border ("NOB") market, thereby providing unique market diversity to the Company for the benefit of retail customers.

Q. Is the cost of the DC Intertie out of line with the cost of other transmission?

A. No. For example, point-to-point transmission service under the Company's OATT, including scheduling, costs approximately $2.20 per KW-month, and the cost of the DC Intertie is approximately $1.95 per KW-month.

Q. Does the DC Intertie have other value that is not captured by the GRID model?

A. Yes. The Company's 2013 IRP relies on market capacity from the DC Intertie and the NOB market to serve peak load. Between 2013 and 2032, the Company's 2013 IRP preferred portfolio selected 100 MW of front office transactions from the NOB market annually to reliably meet its retail loads. If the DC Intertie was not available in the IRP, the Company would be required to acquire capacity from another source. An analysis completed using the Company's IRP models with and without the DC Intertie capacity shows higher system costs if the DC Intertie is excluded, with the 20-year present value revenue requirement differential benefit of the DC Intertie exceeding $85 million.

Q. Is it true that termination of the DC Intertie contract is tied to the AC Intertie agreement with BPA?

A. Yes. Consistent with the LOU, the life of the DC Intertie contract is tied to the AC Intertie agreement and the life of the underlying facilities. The ability to terminate the DC Intertie contract is tied to termination of the Company's AC Intertie agreement. If this were to occur, the Company would no longer have the ability to sell wholesale power over the AC Intertie. This outcome would certainly increase NPC.

Q. Does the LOU support that the DC Intertie contract was prudent when executed and that it also provides benefits to the Company's customers today?

A. Yes. The LOU illustrates that the DC Intertie is an integral piece of the transmission network in PACW for meeting load and providing access to wholesale power over the DC Intertie as well as the AC Intertie.

Energy Imbalance Market

Q. Please describe the EIM and how it will impact NPC.

A. As proposed, the EIM is a balancing market that optimizes generator dispatch every five minutes within and between the PacifiCorp and CAISO balancing authority areas ("BAAs"). The EIM will allow for more reliable and lower cost operation than is possible with the bilateral hourly market transactions currently available to the Company. An implementation agreement was approved by the Federal Energy Regulatory Commission ("FERC") effective July 1, 2013, and the EIM is targeted to begin (1) operation with PacifiCorp's east BAA ("PACE") and PACW, and (2) participation in the market with the CAISO BAAs, October 1, 2014. Participation in the EIM is expected to produce benefits to customers in the form of reduced net power costs, partially offset by costs for initial startup and ongoing operation.

Q. Have the net benefits of EIM participation been identified?

A. Yes; however, because the EIM market design is ongoing, the projected benefits and costs are highly uncertain at this time. The potential benefits of the EIM were analyzed by Energy and Environmental Economics, Inc. ("E3") in a report dated

March 13, 2013[9] E3 identified that the creation of the EIM would produce four principal benefits: interregional dispatch savings, intraregional dispatch savings, reduced flexibility reserves, and reduced renewable energy curtailment (applicable only to CAISO). The projected value of these benefits attributed to the Company is sensitive to modeling assumptions and varies over a wide range.

Costs of EIM participation include a one-time charge for the CAISO to expand its network model, plus capital costs and ongoing operation and maintenance ("O&M") costs. Ongoing O&M expenses fall into two general categories: variable fees paid to CAISO, and O&M related to additional headcount and IT systems and support. Variable fees paid to CAISO consist of a new administrative fee based on actual transactions executed as part of the EIM and additional market charges incurred when doing business with CAISO.

Q. Have you included the EIM costs and benefits in this case?

A. No. Due to the uncertainty surrounding the level of benefits that will be achieved and the costs that will be incurred, particularly in the early stages of EIM operation, the Company has not included the impact of the EIM in this case.

Q. If the EIM achieves commercial operation in October 2014 as planned, how should the net benefits be incorporated into customers' rates?

A. The actual costs and benefits, including those costs not booked to NPC accounts, should be passed back to customers via the EBA, at least until such time as the costs and benefits are reflected in retail rates. If the Commission does not approve EBA treatment as described in greater detail below, the Company requests that

[9] http://www.caiso.com/Documents/PacifiCorp-ISOEnergyImbalanceMarketBenefits.pdf.

non-NPC amounts be deferred as a regulatory asset in Account 182 for later inclusion in customer rates.

Q. Will all EIM-related costs and benefits automatically flow through EBA accounts?

A. No. While EIM benefits will automatically flow through the EBA in the form of lower NPC, out of all the cost categories, only the market charges will be booked to EBA accounts. Even though the CAISO administrative fees will vary based on the transactions executed over a given time period, FERC and CAISO determined that the fees should be booked to FERC accounts 561 and 575 - non EBA accounts. Notwithstanding this accounting treatment, the Company proposes that these costs be permanently included in the EBA and subject to annual true-up (and sharing band) along with other EBA costs.

Other O&M and capital expenditures for EIM will also not be booked to accounts that flow through the EBA. The Company proposes to track these costs for later recovery through the EBA as a specific adder or adjustment, also subject to the EBA sharing band. Once these costs are included in base rates through a future general rate case, an EBA adder for these specific costs will no longer be necessary.

NPC Updates

Q. Does the Company propose to update NPC during the course of this proceeding in order to improve the accuracy of the NPC projections?

A. Yes. Since the implementation of the EBA, Base NPC is set in general rate cases for later comparison to actual NPC during the rate effective period. In order to achieve the most accurate forecast of Base NPC, and thus minimize the deferred NPC, the Company proposes to update the following limited categories of NPC:

- The OFPC for electricity and natural gas;
- Coal contracts;
- Wholesale sales and purchase contracts for electricity and natural gas, for both physical and financial products;
- Transmission contracts to wheel generation to load centers; and
- Transportation contracts to deliver natural gas to generation facilities.

Q. Did the Company file updates to NPC in the 2012 GRC?

A. Yes. The Company filed updates to the same limited categories listed above in the 2012 GRC several weeks prior to parties filing of direct testimony, per the schedule set in the Scheduling Order in the 2012 GRC. No party objected to the updates and the updated NPC was the basis for the NPC adopted in the settlement stipulation in that case.

Q. Did parties raise any concerns with regard to the Company's update process in the 2012 GRC?

A. Yes. Two parties indicated that the one-month interval between the Company's update filing and the filing of their direct testimony was insufficient for them to fully address the updates. The Division of Public Utilities ("DPU") suggested a six-week interval would be more appropriate, whereas the Office of Consumer Services ("OCS") advocated for an approximate 10-week interval.

Q. How do you respond to the concerns regarding the timing of the updates?

A. The Company acknowledges that the update process must balance the inclusion of the most recently available information against the need for verification by other parties. In the 2012 GRC, nearly all of the Company's 15 updates to NPC were for new contracts, new pricing provided by counterparties according to contract terms, or terminated contracts. These are well-documented interactions with third parties that should be straight-forward to review. Parties were provided supporting documentation and workpapers for seven of the updates nine weeks prior to their filing of direct testimony. Supporting materials for five additional updates were provided six weeks prior to their filing, and the complete support for all of the updates and their cumulative impact was provided four weeks prior to parties filing direct testimony.

Q. What is the Company proposing in this case?

A. The Company is requesting that the Commission establish a fixed schedule of when NPC updates will occur over the course of a rate case proceeding and what particular NPC items will be updated. This will ensure that the update process is applied consistently and that no party will selectively accept or reject updates only on the basis that they increase or decrease NPC.

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

A. The Company proposes to update NPC for the limited categories prior to parties' filing their direct testimony. In this proceeding, the Company proposes to file the update one month prior to the date that other parties will file direct testimony. In addition, prior to the update filing, the Company will periodically provide new information in those categories that will be reflected in the update filing, either on a monthly basis or when a significant amount of information has been accumulated. The Company believes that this will allow adequate time for parties to review the information prior to filing their direct testimony.

Q. Does the Company have a specific recommendation with regard to the update of its OFPC?

A. The Company recommends that its update filing utilize the March 31, 2014, OFPC. The Company will make the workpapers underlying this update available for parties to review during early April 2014, which should be well before their direct testimony is filed. This will provide a reasonable balance between the benefits of up-to-date information against the time needed for review.

Q. What other updates does the Company anticipate?

A. In addition to the list of update categories cited earlier, FERC recently approved BAL-002-WECC-2, which modifies the contingency reserve requirements, effective January 28, 2014. Implementation is "the first day of the 3rd quarter following regulatory approval," which will be October 2014. The current contingency reserve requirement is for the sum of five percent of load responsibility served by hydro generation and seven percent of the load responsibility served by thermal generation. Wind and solar is treated the same as hydro. The newly approved contingency reserve requirement is for the sum of three percent of hourly integrated load plus three percent of hourly integrated generation. The timing of the ruling did not allow enough time for the Company to create a precise methodology in GRID that would accurately capture the impact of the modified reserve requirement in its direct testimony.

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

A. The Company's load and resource balance for the test period changes with market prices and contracts. As a result, the operation of the Company's system continues to change during the course of the general rate case proceeding. The Company's proposal to update NPC will ensure that the NPC forecast for the rate effective period is as accurate as possible.

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

A. No. The Company believes the review time is reasonable given the limited scope of the update and the provision of new information in a timely fashion. These updates are transparent, apply equally whether they increase or decrease NPC, can be easily verified and are straightforward to model in GRID. In addition, the Company will provide work papers to support these updates.

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

A. Yes. This has become regular practice in Oregon and Washington with the goal of improving the accuracy of the NPC in rates. For example, the Oregon Public Utility Commission authorizes the Company to update its forward price curve and new information on contracts for electricity and natural gas after it has entered its final order, but prior to the time rates go into effect.

Q. Does this conclude your direct testimony?

A. Yes.

Rocky Mountain Power
Exhibit RMP___(GND-1)
Docket No. 13-035-184
Witness: Gregory N. Duvall

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Gregory N. Duvall

Net Power Costs

January 2014

PacifiCorp

_UTGRC14 NPC Study_2013 11 20

Net Power Cost Analysis

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12 months ended June 2015	07/14-06/15	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15
Special Sales For Resale													
Long Term Firm Sales													
Black Hills s27013/s28160	13,947,138	1,170,604	1,177,673	1,154,222	1,179,600	1,148,473	1,182,495	1,174,617	1,119,201	1,185,806	1,147,468	1,161,198	1,145,781
BPA Wind s42818	2,756,997	123,965	124,596	175,863	219,445	306,794	383,612	298,403	267,250	297,745	186,990	191,247	181,087
Hurricane Sale s393046	13,751	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146
LADWP (IPP Layoff)	29,139,801	2,830,751	2,828,315	2,013,576	3,397,116	2,281,743	2,504,305	2,402,996	2,058,084	2,080,694	1,645,803	2,403,743	2,692,677
Leaning Juniper Revenue	112,205	12,856	13,162	10,703	9,855	7,676	8,243	7,081	7,455	11,689	6,476	8,292	8,716
Shell Sale 2013-2014	1,438,795	718,792	720,003	-	-	-	-	-	-	-	-	-	-
SMUD s24296	5,397,375	1,426,350	1,900,875	1,698,300	352,425	19,425	-	-	-	-	-	-	-
UMPA II s45631	9,556,305	1,779,848	1,400,150	792,640	593,283	582,825	593,283	593,283	561,909	593,283	582,825	568,590	914,390
Total Long Term Firm Sales	62,362,366	8,064,312	8,165,920	5,846,450	5,752,869	4,348,081	4,673,083	4,477,525	4,015,045	4,170,363	3,570,706	4,334,216	4,943,797
Short Term Firm Sales													
Palo Verde	894,440	-	-	-	-	-	-	310,780	272,880	310,780	-	-	-
Electric Swaps Sales	1,698,293	(347,984)	(267,488)	(25,000)	693,450	739,335	905,980	-	-	-	-	-	-
Total Short Term Firm Sales	2,592,733	(347,984)	(267,488)	(25,000)	693,450	739,335	905,980	310,780	272,880	310,780	-	-	-
System Balancing Sales													
COB	36,969,217	4,039,545	4,576,657	4,076,010	3,268,275	3,835,989	4,254,946	4,271,850	3,133,591	2,967,805	1,649,770	442,456	452,325
Four Corners	64,755,930	5,444,080	7,829,008	7,207,942	5,467,854	6,045,004	5,173,646	6,234,965	5,387,732	4,058,501	4,588,512	3,851,161	3,467,526
Mead	35,192,453	2,516,602	3,374,999	3,820,423	3,114,039	3,640,420	3,239,570	3,983,201	3,146,958	2,431,060	2,148,575	1,978,584	1,798,022
Mid Columbia	11,754,194	1,003,365	1,690,011	1,925,102	1,963,191	1,073,762	387,038	955,980	1,073,197	1,618,916	31,285	11,332	21,014
Mona	13,746,457	1,531,759	2,227,051	2,367,576	1,414,904	638,694	533,656	617,225	384,340	262,244	859,709	1,696,305	1,212,995
Palo Verde	122,575,507	12,023,837	10,345,780	11,128,275	10,706,790	9,877,691	9,266,895	10,405,704	10,274,396	9,267,444	9,136,731	9,673,198	10,468,766
Trapped Energy	124,525	2,033	-	7,084	2,196	-	48,090	-	34,486	-	9,038	18,851	2,748
Total System Balancing Sales	285,118,283	26,561,220	30,043,505	30,532,412	25,937,249	25,111,560	22,903,841	26,468,925	23,434,699	20,605,969	18,423,620	17,671,887	17,423,395
Total Special Sales For Resale	350,073,382	34,277,549	37,941,937	36,353,862	32,383,568	30,198,976	28,482,904	31,257,230	27,722,624	25,087,112	21,994,326	22,006,103	22,367,193

Purchased Power & Net Interchange

Long Term Firm Purchases													
APS Supplemental p27875	533,477	-	-	-	-	114,939	107,663	56,121	152,784	-	101,970	-	-
Combine Hills Wind p160595	4,955,859	394,481	391,207	372,846	400,343	446,575	325,411	496,898	323,085	574,537	403,458	375,039	451,979
Deseret Purchase p194277	34,942,116	2,795,067	2,994,284	2,960,184	3,003,258	2,960,184	3,003,258	3,083,965	2,951,197	3,083,965	3,002,829	2,460,683	2,643,245
Douglas PUD Settlement p38185	2,025,404	227,530	158,198	87,026	77,569	80,799	105,614	105,066	94,453	156,892	254,239	325,632	352,386
Gemstate p99489	3,211,600	260,500	279,400	260,500	282,900	293,500	263,700	263,700	260,500	265,400	260,500	260,500	260,500
Georgia-Pacific Camas	6,468,239	546,556	546,556	528,925	546,556	528,925	546,556	552,204	498,766	552,204	534,392	552,204	534,392
Hermiston Purchase p99563	83,679,292	7,447,431	8,122,781	7,766,487	8,402,983	8,225,493	8,283,390	7,574,769	7,093,441	7,249,426	4,797,163	4,215,893	4,500,034
Hurricane Purchase p393045	125,120	10,427	10,427	10,427	10,427	10,427	10,427	10,427	10,427	10,427	10,427	10,427	10,427
IPP Purchase	29,139,801	2,830,751	2,828,315	2,013,576	3,397,116	2,281,743	2,504,305	2,402,996	2,058,084	2,080,694	1,645,803	2,403,743	2,692,677
MagCorp Reserves p510378	6,355,850	533,330	537,340	545,360	569,420	549,370	553,380	533,330	581,450	545,360	469,170	461,150	477,190
Nucor p346856	6,018,000	501,500	501,500	501,500	501,500	501,500	501,500	501,500	501,500	501,500	501,500	501,500	501,500
P4 Production p137215/p145258	19,999,999	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667
PGE Cove p83984	323,118	26,927	26,927	26,927	26,927	26,927	26,927	26,927	26,927	26,927	26,927	26,927	26,927
Rock River Wind p100371	4,940,852	193,726	234,387	304,450	436,506	593,879	610,936	602,477	475,464	480,834	376,185	360,263	271,745
Small Purchases east	56,350	3,623	3,956	5,488	4,433	4,476	5,107	5,310	5,186	6,277	4,722	3,887	3,884
Three Buttes Wind p460457	20,598,497	1,054,248	1,080,038	1,423,019	1,787,221	2,006,943	2,406,511	2,305,957	1,595,827	2,351,682	1,690,904	1,714,597	1,181,550
Top of the World Wind p522807	40,244,926	1,930,210	2,086,321	2,260,849	2,895,794	4,238,572	5,565,507	5,293,915	3,991,015	3,804,703	3,095,178	2,664,502	2,418,363
Tri-State Purchase p27057	10,422,772	928,311	919,965	902,330	899,347	810,530	792,328	920,456	840,551	805,583	884,657	853,693	865,021
Wolverine Creek Wind p244520	10,208,473	843,890	791,566	736,652	637,178	834,559	664,094	760,815	599,185	1,196,907	1,150,456	1,120,408	872,763
Long Term Firm Purchases Total	284,249,745	22,195,174	23,179,834	22,373,209	25,546,142	26,176,006	27,943,281	27,163,499	23,726,509	25,359,984	20,877,146	19,977,714	19,731,248
Seasonal Purchased Power													
Constellation 2013-2016	5,831,392	2,027,584	1,991,808	1,812,000	-	-	-	-	-	-	-	-	-
Seasonal Purchased Power Total	5,831,392	2,027,584	1,991,808	1,812,000	-	-	-	-	-	-	-	-	-

Qualifying Facilities													
QF California	6,815,022	358,150	271,193	251,976	254,706	279,794	413,518	637,102	714,158	794,372	1,013,580	1,028,701	797,773
QF Idaho	7,444,590	601,567	486,992	435,986	467,246	460,032	436,690	616,427	562,109	694,144	757,952	917,494	1,007,951
QF Oregon	25,898,893	1,920,331	1,807,574	1,877,770	1,831,228	1,673,473	2,034,446	2,282,972	2,142,793	2,435,834	2,709,734	2,743,395	2,439,345
QF Utah	2,087,163	129,083	125,176	109,054	123,353	124,136	99,664	134,724	162,620	193,954	209,799	239,226	436,375
QF Washington	603,070	83,070	87,270	75,440	44,681	29,520	29,466	31,328	31,324	31,290	35,658	51,401	72,623
QF Wyoming	643,270	115,151	115,036	104,170	58,055	32,687	32,769	22,474	21,144	20,448	48,650	36,157	36,528
Biomass One QF	14,029,834	1,377,174	1,377,252	1,368,446	1,398,072	1,315,261	1,221,266	1,302,686	1,190,159	1,319,319	718,405	723,393	718,402
Chevron Wind p499335 QF	2,069,531	146,940	241,299	200,991	302,335	322,556	196,925	177,285	161,313	154,308	56,195	58,707	50,676
DCFP p316701 QF	140,852	9,707	4,716	10,179	17,739	14,686	5,096	11,722	9,042	10,351	10,351	19,288	17,977
Evergreen BioPower p351030 QF	2,453,125	191,420	265,265	252,112	297,472	210,202	208,386	194,715	189,958	176,523	141,532	157,092	168,446
Five Pine Wind QF	7,217,179	512,565	606,222	514,570	623,024	682,098	853,377	671,391	572,575	680,769	532,192	533,286	435,110
Latigo Wind Park QF	1,352,141	-	-	-	-	-	-	-	-	-	-	735,564	616,578
Mountain Wind 1 p367721 QF	8,465,020	407,927	518,460	646,004	719,796	835,772	1,120,054	1,204,831	771,242	797,935	584,542	493,472	364,985
Mountain Wind 2 p398449 QF	12,244,876	808,202	792,575	815,405	855,555	1,122,506	1,528,677	1,758,851	1,078,685	1,124,962	797,084	859,408	702,966
North Point Wind QF	15,782,073	1,142,389	1,345,965	1,143,273	1,371,132	1,474,807	1,847,130	1,454,189	1,243,197	1,472,266	1,168,023	1,156,823	962,878
OM Power I Geothermal QF	4,064,537	255,303	264,429	301,315	357,096	370,301	386,415	397,772	356,226	393,355	350,700	340,413	291,214
Oregon Wind Farm QF	11,545,986	1,335,923	1,039,607	844,531	848,682	1,000,640	346,199	691,263	738,788	952,230	1,170,368	1,187,991	1,389,764
Power County North Wind QF p5756	3,987,350	276,642	249,121	289,603	378,449	364,660	480,197	379,580	383,534	351,063	330,930	266,151	237,420
Power County South Wind QF p5756	3,816,504	206,895	211,715	258,681	324,356	378,622	508,064	410,977	368,187	379,161	298,713	235,677	235,457
Roseburg Dillard QF	994,462	129,981	117,533	100,558	33,032	79,425	115,472	127,526	128,280	63,321	43,795	24,270	31,268
Spanish Fork Wind 2 p311681 QF	2,820,209	290,998	345,406	280,936	229,198	252,903	275,850	183,965	199,368	175,977	166,978	170,414	248,216
Sunnyside p83997/p59965 QF	27,539,226	2,437,299	2,367,324	2,353,845	2,051,822	2,384,263	2,452,629	2,451,869	2,344,758	2,454,297	1,629,359	2,205,904	2,405,857
Tesoro QF	638,319	96,966	91,069	97,285	110,299	101,638	141,061	-	-	-	-	-	-
Threemile Canyon Wind QF p50013	2,044,975	165,930	169,994	159,382	183,597	144,615	151,783	152,303	159,689	178,983	167,021	212,401	199,278
Qualifying Facilities Total	164,698,206	12,999,614	12,901,192	12,491,510	12,880,924	13,654,593	14,885,132	15,295,952	13,529,150	14,854,862	12,941,561	14,396,629	13,867,086
Mid-Columbia Contracts													
Douglas - Wells p60828	3,606,733	296,741	296,741	301,325	301,325	301,325	301,325	301,325	301,325	301,325	301,325	301,325	301,325
Grant Reasonable	(6,047,193)	(487,731)	(487,731)	(487,731)	(487,731)	(487,731)	(487,731)	(520,135)	(520,135)	(520,135)	(520,135)	(520,135)	(520,135)
Grant Surplus p258951	1,863,959	154,085	154,085	154,085	154,085	154,085	154,085	156,575	156,575	156,575	156,575	156,575	156,575
Mid-Columbia Contracts Total	(576,502)	(36,905)	(36,905)	(32,321)	(32,321)	(32,321)	(32,321)	(62,235)	(62,235)	(62,235)	(62,235)	(62,235)	(62,235)
Total Long Term Firm Purchases	454,202,842	37,185,467	38,035,930	36,644,399	38,394,745	39,798,278	42,796,091	42,397,217	37,193,424	40,152,611	33,756,473	34,312,108	33,536,100

Storage & Exchange													
APS Exchange p58118/s58119	-	-	-	-	-	-	-	-	-	-	-	-	-
BPA FC II Wind p63507	-	-	-	-	-	-	-	-	-	-	-	-	-
BPA FC IV Wind p79207	-	-	-	-	-	-	-	-	-	-	-	-	-
BPA So. Idaho p64885/p83975/p647	(119)	(112)	-	(7)	-	-	-	-	-	-	-	-	-
Cowlitz Swift p65787	-	-	-	-	-	-	-	-	-	-	-	-	-
EWEB FC I p63508/p63510	-	-	-	-	-	-	-	-	-	-	-	-	-
PSCo Exchange p340325	5,400,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000
PSCO FC III p63362/s63361	-	-	-	-	-	-	-	-	-	-	-	-	-
Redding Exchange p66276	-	-	-	-	-	-	-	-	-	-	-	-	-
SCL State Line p105228	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Storage & Exchange	5,399,881	449,888	450,000	449,993	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000
Short Term Firm Purchases													
Mid Columbia	1,005,360	-	-	-	-	-	-	349,320	306,720	349,320	-	-	-
STF Electric Swaps	(725,991)	(81,822)	(416,676)	(78,675)	167,994	(48,960)	(267,852)	-	-	-	-	-	-
Total Short Term Firm Purchases	279,369	(81,822)	(416,676)	(78,675)	167,994	(48,960)	(267,852)	349,320	306,720	349,320	-	-	-
System Balancing Purchases													
COB	7,808,815	682,439	195,570	280,864	135,210	140,282	250,816	92,506	32,454	60,909	430,715	2,654,906	2,852,143
Four Corners	5,811,210	877,611	763,139	262,696	464,557	688,867	722,781	260,855	175,196	915,111	267,064	129,980	283,352
Mead	31,187	-	278	-	10,471	653	12,004	2,516	836	1,297	1,357	1,372	403
Mid Columbia	82,993,365	15,536,533	11,526,532	2,292,202	2,044,497	490,139	1,461,273	1,210,540	1,204,370	2,892,710	13,868,025	15,535,785	14,930,760
Mona	30,932,106	722,620	537,337	1,020,155	1,122,827	4,325,117	3,878,060	3,974,101	4,219,582	6,015,846	2,129,464	1,612,739	1,374,259
NOB	145,551	20,715	-	-	-	-	-	-	-	-	-	46,631	78,205
Total System Balancing Purchases	127,722,234	17,839,918	13,022,856	3,855,917	3,777,561	5,645,057	6,324,934	5,540,517	5,632,439	9,885,872	16,696,625	19,981,414	19,519,123
Total Purchased Power & Net Inte	587,604,325	55,393,451	51,092,110	40,871,634	42,790,300	45,844,376	49,303,173	48,737,054	43,582,583	50,837,804	50,903,098	54,743,522	53,505,222

Wheeling & U. of F. Expense													
Firm Wheeling	147,375,313	12,809,647	12,841,393	11,489,077	11,789,710	12,316,588	12,638,397	12,449,911	12,474,629	12,532,456	11,778,696	11,734,423	12,520,387
ST Firm & Non-Firm	36,617	914	970	2,311	1,633	1,184	7,871	8,385	5,724	2,869	1,494	1,282	1,980
Total Wheeling & U. of F. Expense	147,411,930	12,810,561	12,842,363	11,491,388	11,791,343	12,317,772	12,646,268	12,458,296	12,480,353	12,535,325	11,780,190	11,735,705	12,522,366
Coal Fuel Burn Expense													
Carbon	18,832,132	2,020,864	2,035,177	1,597,756	1,856,268	1,984,500	2,076,772	2,109,636	1,969,938	2,211,276	973,048	(1,460)	(1,642)
Cholla	55,361,191	4,276,106	4,842,759	4,694,458	4,824,380	4,995,104	5,019,747	5,170,803	4,859,517	5,260,530	3,114,024	4,195,700	4,108,062
Colstrip	15,222,594	1,364,919	1,363,599	1,321,030	1,364,869	1,318,663	1,364,431	1,364,511	1,231,883	1,364,272	1,320,724	814,685	1,029,006
Craig	24,748,808	2,216,396	2,209,750	2,134,308	1,748,181	1,354,634	2,219,307	2,220,659	2,004,670	2,219,989	2,148,173	2,182,092	2,090,650
Dave Johnston	62,033,041	5,705,205	5,716,518	5,460,469	5,447,158	5,110,545	4,978,437	5,159,109	4,687,387	3,919,689	5,211,976	5,350,695	5,285,853
Hayden	12,945,675	1,140,862	1,117,720	1,027,929	1,107,636	1,271,204	1,251,438	1,230,037	1,142,501	1,313,163	869,842	562,394	910,949
Hunter	160,842,764	13,985,644	14,764,003	13,740,490	13,840,088	13,391,031	13,871,234	14,376,533	13,075,966	9,792,468	13,006,165	13,635,214	13,363,926
Huntington	126,313,919	11,127,492	11,565,655	9,931,855	8,489,277	8,886,709	11,103,400	11,474,339	10,459,143	11,355,899	10,751,382	10,736,830	10,431,937
Jim Bridger	229,003,285	20,223,347	20,359,793	19,217,723	20,710,165	20,533,848	20,749,158	20,372,982	18,636,496	19,250,178	15,804,461	15,421,138	17,723,995
Naughton	91,887,054	10,707,937	10,856,385	10,473,272	10,410,076	9,892,670	10,515,716	5,653,941	5,128,249	5,537,993	3,790,364	4,178,747	4,741,704
Wyodak	26,432,503	2,343,561	2,347,199	2,264,332	2,320,883	2,297,135	2,244,801	2,382,911	2,083,355	2,301,041	1,353,350	2,256,160	2,237,776
Total Coal Fuel Burn Expense	823,622,967	75,112,334	77,178,560	71,863,624	72,118,981	71,036,042	75,394,440	71,515,462	65,279,104	64,526,498	58,343,509	59,332,197	61,922,216
Gas Fuel Burn Expense													
Chehalis	31,427,817	6,346,291	6,801,236	5,887,768	5,556,484	1,828,770	1,214,242	2,358,078	1,218,371	216,578	-	-	-
Currant Creek	37,457,951	4,720,950	6,026,639	3,989,636	1,157,732	1,330,791	948,925	2,522,836	3,203,842	3,278,394	3,764,463	3,260,581	3,253,163
Gadsby	3,222,172	1,432,842	1,686,301	103,029	-	-	-	-	-	-	-	-	-
Gadsby CT	2,545,680	544,026	672,425	337,652	245,307	60,304	9,782	33,983	28,692	44,287	158,321	94,777	316,123
Hermiston	34,278,749	3,030,827	3,697,648	3,400,321	3,589,968	3,458,730	3,550,617	3,878,243	3,436,222	3,560,710	1,179,053	605,259	891,150
Lake Side 1	54,968,758	6,816,331	8,111,858	6,263,278	3,185,635	3,157,104	3,309,818	4,777,157	5,650,929	5,528,677	2,548,952	2,115,210	3,503,810
Lake Side 2	78,674,761	6,853,988	7,499,930	6,868,956	6,206,575	6,789,710	7,068,323	7,865,584	7,063,758	6,615,839	3,643,676	5,430,323	6,768,099
Naughton - Gas	104,479	-	-	-	-	-	-	-	-	-	-	-	104,479
Total Gas Fuel Burn	242,680,367	29,745,254	34,496,036	26,850,640	19,941,701	16,625,408	16,101,707	21,435,881	20,601,815	19,244,486	11,294,465	11,506,150	14,836,824
Gas Physical	(44,588)	(11,238)	(11,238)	(10,875)	(11,238)	-	-	-	-	-	-	-	-
Gas Swaps	26,994,125	4,233,639	4,151,970	3,951,285	3,010,410	2,802,105	2,457,541	693,734	672,462	843,975	1,411,950	1,430,805	1,334,250
Clay Basin Gas Storage	221,883	50,533	50,533	50,533	50,533	10,667	(24,187)	(49,540)	(41,888)	(26,899)	50,533	50,533	50,533
Pipeline Reservation Fees	36,208,549	3,042,586	3,042,586	2,994,205	3,042,586	2,994,205	3,042,586	3,042,586	2,905,633	3,042,586	2,978,820	3,027,200	3,052,973
Total Gas Fuel Burn Expense	306,060,336	37,060,774	41,729,887	33,835,788	26,033,992	22,432,385	21,577,645	25,122,660	24,138,023	23,104,147	15,735,767	16,014,688	19,274,580
Other Generation													
Blundell	3,757,234	313,013	313,101	312,699	333,207	332,340	343,304	343,353	310,119	343,353	311,734	198,085	302,927
Integration Charge	3,476,168	253,466	251,114	244,789	274,024	308,872	332,130	349,011	285,833	330,677	282,334	285,996	277,922
Total Other Generation	7,233,402	566,478	564,216	557,488	607,231	641,212	675,434	692,363	595,951	674,030	594,068	484,082	580,849
Net Power Cost	**1,521,859,578**	146,666,051	145,465,198	122,266,061	120,958,278	122,072,811	131,114,057	127,268,607	118,353,390	126,590,691	115,362,305	120,304,090	125,438,040
Net Power Cost/Net System Load	**25.78**	**27.28**	**27.53**	**26.27**	**26.00**	**25.35**	**25.03**	**24.09**	**25.26**	**25.85**	**24.91**	**25.63**	**26.05**

Rocky Mountain Power
Exhibit RMP___(GND-2)
Docket No. 13-035-184
Witness: Gregory N. Duvall

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Gregory N. Duvall

DC Intertie Letter of Understanding

January 2014

PACIFICORP
PACIFIC POWER UTAH POWER

INTERNAL CORRESPONDENCE

"CONFIDENTIAL"

DATE: June 1, 1993

TO: Central Files - 195 MEZZ

FROM: Jerry Miller - 424 PSB JM

SUBJECT: May 28, 1993 Letter of Understanding between PacifiCorp and Bonneville Related to Intertie Issues

Enclosed for vault files is a fully executed original of the above referenced Letter of Understanding.

The Letter of Understanding lists the principles, which will be embodied in the appropriate contracts, between PacifiCorp and Bonneville related to PacifiCorp's use of the Pacific Northwest to Pacific Southwest A.C. and D.C. Interties.

The Letter of Understanding will not be filed with the FERC. The affected contracts and contract amendments will be filed pursuant to the FERC's rules and regulations.

The Letter of Understanding or its content are not to be released without the consent of Dennis P. Steinberg, Floyd Hammerquist or Jerry Miller.

cc: Bayless, Cory, Duvall, Eakin-1228 PSB, Eddy-270 NTO, Galloway-27 SIC, Hammerquist, Hill-SPCC, Johannsen, Kaake-SPCC, Morris-330 NTO, Persichetti, Sickels, Stamper, Steinberg-1600 POP, Sias, Walton-330 NTO, Watters, Wood-27 SIC

File: BPA

Department of Energy
Bonneville Power Administration
P.O. Box 3621
Portland, Oregon 97208-3621

OFFICE OF THE ADMINISTRATOR

In reply refer to: PMTI

MAY 28 1993

Mr. Dennis P. Steinberg
Vice President
Power Systems & Development
PacifiCorp
700 NW. Multnomah, Suite 1600
Portland, OR 97232

Dear Mr. Steinberg:

PacifiCorp and the Bonneville Power Administration (Bonneville) have reached agreement on principles to resolve a number of outstanding issues related to the Intertie Agreement, Contract No. DE-MS79-86BP92299, and the Midpoint-Medford Agreement, Contract No. DE-MS79-79BP90091. Therefore, subject to Bonneville's statutory requirements, including appropriate environmental review, the parties agree to finalize appropriate agreements to implement the following:

1. <u>PacifiCorp's South-to-North AC Intertie Scheduling Rights Under the Intertie Agreement</u>. PacifiCorp will have the following rights:

   (a) PacifiCorp's south-to-north (S>N) Intertie scheduling rights under the Intertie Agreement will equal 400 MW divided by the north-to-south (N>S) rated transfer capability (RTC) times the S>N RTC. PacifiCorp agrees to cooperate with Bonneville in its efforts to secure up to a 4800 MW S>N RTC.

   (b) PacifiCorp shall have the right to net its N>S and S>N schedules.

   (c) The Intertie Agreement shall be amended to explicitly state that the Agreement applies to the parties' S>N rights as well as to the parties' N>S rights.

2. <u>Priority S>N Non-Firm Transmission for PacifiCorp</u>:

   (a) For a term of 30-years, on hours that PacifiCorp's S>N scheduling capability (including rights under 1(a), net schedules under 1(b), NFP under 3(a), and firm transmission services under 3(a) or 3(b)) is less than 582 MW on off-peak hours, Bonneville will provide PacifiCorp the right to utilize unused Bonneville S>N AC and DC capability at the IS-A rate. Unused Bonneville S>N capability, for up to a total of 582 MW of S>N scheduling capability, is defined as capability not required to satisfy Bonneville's firm contractual commitments as determined by Bonneville.

3. PacifiCorp's Additional Intertie Delivery Rights:

(a) Non-Federal Participation (NFP). Bonneville's current draft of the Environmental Impact Statement (EIS) for NFP includes analysis of impacts of additional NFP above 725 MW. In the event that Bonneville offers additional NFP, Bonneville will propose to make 125 MW available to PacifiCorp. If the Administrator has not issued a Record of Decision in favor of proceeding with an additional NFP offer of at least 125 MW of NFP by January 1, 1994, then Bonneville shall offer PacifiCorp interim firm transmission contract(s) that will provide 125 MW of N>S wheeling for PacifiCorp's WAPA and Redding contracts and S>N wheeling equal to 125 x S>N RTC/4800. Such interim firm transmission contract demand for N>S shall be 75 MW starting January 1, 1994, and 125 MW starting June 1, 1994.

(b) If PacifiCorp has not obtained 125 MW of NFP by January 1, 1995, then Bonneville shall offer long-term firm transmission contracts as described in 3(a). PacifiCorp may use such contracts for firm or non-firm schedules. PacifiCorp may use such contract rights up to a 100 percent load factor.

(c) If PacifiCorp executes either an interim firm transmission or a long-term firm transmission contract, the transmission rate applicable to such contract shall be Bonneville's then applicable IS-B rate. PacifiCorp shall pay the IS-B rate based upon a 125 MW N>S contract demand plus a S>N contract demand equal to 125 x S>N RTC/4800 for a term equal to the WAPA and Redding Contracts. The agreement(s) shall otherwise include Bonneville's standard terms and conditions for firm transmission, provided that no mitigation charges shall be applied. The settlement of issues contained in this letter of understanding incorporates all necessary mitigation. If PacifiCorp executes long-term firm transmission contracts for deliveries for its WAPA and Redding contracts, Bonneville agrees that upon the termination date of such contracts, it will offer to extend such services for a period of up to 25 years, based upon Bonneville's then standard terms included in similar agreements, provided that no mitigation charges shall be applied, beyond the applicable FERC-approved Bonneville rates, if PacifiCorp requires such service.

(d) If PacifiCorp executes a N>S interim firm transmission contract or a N>S long-term firm transmission contract pursuant to 3(a) or 3(b) PacifiCorp, in addition to the contract demand charges, agrees to pre-pay, on a take or pay basis, the then effective energy component of the IS-B rate based on a 85 percent load factor. PacifiCorp shall pay one-twelfth of such amount each month. Based on Bonneville's estimated IS-B (93) rate, such amount would be calculated as follows: 125 MW x 8760 hr x 1.43 M/kWh x 0.85 ÷ 12 = $110,914.37/mo.

(e) If PacifiCorp executes a S>N interim firm transmission contract or a S>N long-term firm transmission contract pursuant to 3(a) or 3(b) PacifiCorp shall not be required to pre-pay any charges for such service beyond the contract demand charges associated with such contract. (No pre-payment of the IS-B energy charge).

(f) PacifiCorp's Main Grid Wheeling Rights to Access the AC Intertie. If PacifiCorp received NFP rights or if PacifiCorp executes interim or long-term firm transmission contracts pursuant to this Section 3, it is agreed that PacifiCorp shall require no additional main grid wheeling on the Federal System to use the rights described above. However, if insufficient capacity exists in the Midpoint-Malin 500 kV Transmission Line segment, then appropriate charges shall be applied consistent with the Intertie Agreement.

(g) In order to implement these principles, the parties agree to establish Summer Lake, Malin, Captain Jack, and Alvey as Points of Delivery (POD) in the appropriate agreements. Bonneville also agrees to amend the Surplus Firm Capacity Sale Agreement, Contract No. DE-MS79-92BP93757, to include Summer Lake as a 500 kV POD. Use of the Summer Lake POD by the Parties shall not impact PacifiCorp's load carrying capability (LCC) (as defined in the Intertie Agreement) or Bonneville's usage of the AC Intertie.

4. S>N DC Intertie Rights and West-to-East (W>E) Summer Lake-Midpoint Rights:

(a) Bonneville shall offer PacifiCorp a firm S>N wheeling contract on the DC Intertie for 200 MW. PacifiCorp may use such contract for firm or non-firm deliveries up to a 100 percent load factor. Such contract shall have a term equal to the term of the Intertie Agreement. The contract demand shall be 100 MW starting January 1, 1994, and 200 MW starting January 1, 1995. PacifiCorp shall pay the IS-B, or its successor rate, based upon the yearly contract demands as specified in this Section 4(a). PacifiCorp, in addition to the Contract Demand charges associated with its DC Intertie rights, agrees to pre-pay on a take or pay basis, the then effective energy component of the IS-B rate based on a 30 percent load factor. PacifiCorp shall pay one-twelfth of such amount each month. Based on Bonneville's estimated IS-B (93) rate such amount, based on a 100 MW contract demand, would be calculated as follows: 100 MW x 8760 hr x 1.43 M/kWh x 0.30 ÷ 12 = $31,317/mo. The Agreement shall also include Bonneville's standard terms and conditions for firm transmission, provided that no mitigation charges shall be applied beyond the applicable FERC-approved Bonneville rates. The settlement of issues contained in this letter of understanding incorporates all necessary mitigation.

(b) Midpoint-Medford Transmission Agreement, Contract No. DE-MS79-79BP90091. The term of this Agreement shall be extended for the life of the facilities. Bonneville shall have an option to acquire up to 400 MW of W>E firm scheduling rights over PacifiCorp's Summer Lake-Midpoint 500 kV Line and an option to tap such line to serve loads and for inter-regional transfers. Bonneville's right to exercise its option shall be for the term of the Intertie Agreement. During periods when the W>E transfer capability of PacifiCorp's Summer Lake-Midpoint 500 kV line is reduced, Bonneville's W>E scheduling rights shall be reduced pro-rata with such reduction. However, during periods when transfer capability is reduced, PacifiCorp will provide Bonneville the right to utilize its capability not required for PacifiCorp's firm needs, as determined by PacifiCorp, at no cost. If Bonneville exercises its options for W>E use of the Summer Lake-Midpoint 500 kV line, Bonneville will pay PacifiCorp's then effective applicable FERC filed tariff rate for transmission service. In the event Bonneville desires to tap PacifiCorp's Summer Lake-Midpoint 500 kV line, Bonneville and PacifiCorp shall mutually develop the plan of service for such tap. Such tap shall not degrade or reduce PacifiCorp's East-to-West (E>W) transfer capability on its Midpoint-Malin 500 kV line or reduce PacifiCorp's LCC as defined in the Intertie Agreement. Unless otherwise mutually agreed, Bonneville shall be responsible for all costs associated with such tap. Unless otherwise mutually agreed, such tap shall not increase Bonneville's W>E transfer rights on the Summer Lake-Midpoint line.

(c) PacifiCorp shall enter into an FPT Transmission Agreement associated with its DC Intertie rights, pursuant to 4(a) to wheel power delivered to Big Eddy to PacifiCorp's Main System. If at some future date, PacifiCorp elects to convert to an IR wheeling agreement, then Big Eddy would become a point of integration or interconnection under such IR contract.

5. Intertie Agreement, Contract No. DE-MS79-86BP92299. The term of the Intertie Agreement shall be extended for the life of facilities.

6. Additional Transformer Capacity in Southern Oregon:

(a) PacifiCorp shall provide Bonneville firm capacity in the existing 500/230 kV transformer at Malin, at a use-of-facilities rate, for Bonneville's firm requirements; provided, however, that such capacity will be made available to Bonneville only after PacifiCorp has determined the capacity necessary to meet its own requirements; provided further, that Bonneville's right to use the existing Malin transformer shall be limited to 200 MW.

(b) At such time as the Parties mutually agree, which agreement shall not be unreasonably withheld, that a second 500/230 kV transformer at Malin, or a 500/230 kV transformer at Captain Jack Substation is required, the Parties shall jointly develop the plan of service for such transformer(s). Each Party shall have the right to acquire up to a one-half ownership interest in such transformer(s) at a pro-rata share of cost, provided that PacifiCorp's LCC is not impacted. If a Party does not participate in the ownership at the time such transformer(s) are installed, such Party shall have the unilateral right to acquire up to a one-half ownership interest at a future date to the extent that capacity is available.

7. AC Intertie Reactive Support. After joint studies have been completed and parties mutually agree that additional reactive support is required at Malin or Captain Jack to support the AC Intertie, PacifiCorp shall be financially responsible for its share of such added reactive support.

8. Remedial Action Schemes (RAS) to Support PacifiCorp's AC and DC Intertie Schedules. PacifiCorp shall be responsible for providing or assuring at its cost the provision of its pro rata share of RAS required to support the RTC and OTC of the AC Intertie in either the N>S or S>N direction. In support of its obligations to provide generator dropping for its net N>S AC Intertie schedules, PacifiCorp shall provide generation dropping from its share of Mid-Columbia generation on-line at the time of the RAS requirement. Bonneville may, after it has exhausted its own capability to provide generator dropping in support of its obligation for net N>S AC Intertie Schedules, have access to PacifiCorp's total Mid-Columbia rights on-line at the time of the RAS requirement. Such access to PacifiCorp's Mid-Columbia generator dropping capability by Bonneville shall be at no cost. To the extent that PacifiCorp does not have the capability on-line to provide generator dropping from its Mid-Columbia rights for its net N>S AC Intertie schedules, Bonneville shall, to the extent it has available on-line generation, provide generator dropping capability to PacifiCorp at no cost. In support of PacifiCorp's net S>N schedules on the AC Intertie or its S>N schedules on the DC Intertie, PacifiCorp shall be responsible for making arrangements for any load dropping requirements. To the extent possible, as determined by Bonneville, Bonneville shall offer to sell RAS service to PacifiCorp to enable PacifiCorp to meet its obligations under this Section 8.

9. Midpoint-Medford Agreement Revisions. The following revisions will be made to the Midpoint-Medford Transmission Agreement, Contract No DE-MS79-79BP90091:

   (a) Revise transmission charges in Exhibit E to reflect the elimination of the Hatwai Point of Interconnection.

   (b) Revise Exhibit H to reflect the 1187 MW capability of PacifiCorp's Midpoint-Malin-Medford lines as agreed to by IPC/WWP/BPA and PacifiCorp in the Idaho-Northwest Uprate Agreement, Contract No. DE-MS79-90BP93103.

   (c) Revise Exhibit H to reflect bypass of Burns capacitors.

10. Losses. Prior to energization of PacifiCorp's Dixonville-Meridian 500 kV line and the associated uprating of the AC Intertie N>S RTC to 4800 MW, the parties shall make best efforts to study and reach agreement on an equitable allocation of the parties' control area losses in Southern/Central Oregon associated with the parties' use pursuant to the Intertie Agreements. Such allocation of losses shall consider both heavy and light AC Intertie schedules and area loads, as well as S>N and N>S AC Intertie schedules.

11. Access to Palo Verde. For a period equal to the term of PacifiCorp's March 23, 1993, Transmission Service Agreement with Southern California Edison Company, PacifiCorp, on hours that it does not require its transmission capacity rights under the SCE/TSA, shall offer Bonneville a first right of refusal to utilize PacifiCorp's SCE/TSA transmission rights. PacifiCorp shall have the sole determination as to its requirements to use its SCE/TSA transmission rights. If Bonneville exercises its rights to use PacifiCorp's SCE-TSA transmission rights, Bonneville shall reimburse PacifiCorp its costs under the SCE/TSA. Such cost shall be based on PacifiCorp's then effective transmission demand costs paid to SCE under the SCE/TSA which shall initially be 4.0 M/kWh. If Bonneville exercises its first right of refusal to utilize PacifiCorp's SCE/TSA transmission rights, Bonneville shall use its own AC or DC, as the case may be, Intertie capacity to accept power scheduled under this Section 11. Additionally, such access by Bonneville to PacifiCorp's transmission rights under the SCE/TSA shall not preclude PacifiCorp from utilizing its transmission rights acquired under 3(a), 3(b) or 4(a).

12. Summer Storage. PacifiCorp and Bonneville shall enter into a 20-year agreement whereby PacifiCorp shall accept and store energy for Bonneville during the months of June and July of each year. Such energy shall be delivered to PacifiCorp at POD's specified in Exhibit C of Contract No. DE-MS79-92BP93757 or such other points as may be mutually agreed. PacifiCorp may, but shall not be required to, accept more than 100,000 MWh/mo and Bonneville shall be required to deliver a minimum of 25,000 MWh/mo. Bonneville shall store such energy with PacifiCorp prior to entering into the market to sell surplus energy. Bonneville shall provide notice to PacifiCorp, 1-week prior to the beginning of the month in which energy will be stored, of the amount of energy to be stored by PacifiCorp. The rate of delivery shall be determined by dividing the total energy to be stored in the month by the number of hours in such month, provided, on any hour PacifiCorp shall not be required to back down its thermal units to accept such energy. Except for system emergencies, once the parties have agreed to a schedule for such stored energy, Bonneville shall deliver such energy to PacifiCorp. PacifiCorp shall return such stored energy to Bonneville during the months of September, October, and November of each year in which such energy was delivered to PacifiCorp. The rate of return to Bonneville shall be determined by summing the total energy delivered to PacifiCorp during the prior June and July period, dividing such sum by 3 and dividing such product by the hours in the month in which the energy is to be returned to Bonneville. Except for system emergencies, PacifiCorp shall return such energy to Bonneville at the rate of delivery as determined above. Except for constraints on the parties' transmission systems, the first 110 MW of returned energy shall be delivered to Bonneville at Hot Springs with the remainder delivered to Summer Lake or such other mutually agreed to POD. Storage provided pursuant to this Agreement shall be at no cost to Bonneville.

13. March Energy Option. PacifiCorp and Bonneville shall enter into a 20-year agreement whereby PacifiCorp will deliver to Bonneville, at Hot Springs or such

other mutually agreed to PODs, during off-peak hours, up to 50,000 MWh during the month of March of each year. The maximum rate of delivery for such energy shall be 200 MW/hr. To exercise its option to take this energy, Bonneville shall notify PacifiCorp by February 15 of each year as to the amount of energy Bonneville desires to have delivered during March of such year. Except for system emergencies, PacifiCorp shall deliver such energy to Bonneville. Bonneville shall return such energy to PacifiCorp during the following June 1 through July 15 period during off-peak hours and at a rate of delivery determined by dividing the amount of energy PacifiCorp made available to Bonneville during March by the number of off peak hours in the June 1 through July 15 period. Such March energy shall be returned to PacifiCorp at POD's specified in Exhibit C of Contract No. DE-MS79-92BP93757 or such other points as mutually agreed.

14. Firm Transmission/NFP Exchange Rights. PacifiCorp shall have the right to exchange all or a portion of its AC Intertie firm transmission contract rights acquired pursuant to 3(b) with any party receiving NFP rights for up to 125 MW of NFP rights, to the extent the NFP party has rights to assign all or a portion of its NFP allocation. To the extent Bonneville has a first right of refusal to acquire NFP rights from an NFP party, PacifiCorp's exchange rights under this Section 14 shall have priority. Such exchange between PacifiCorp and the NFP party shall be approved by Bonneville, which approval shall not be unreasonably withheld, and shall ensure that rights, benefits and obligations to Bonneville under the affected agreements are reserved.

The provisions of this letter of understanding are interdependent and not severable. The parties will proceed promptly to draft definitive agreements incorporating the provisions of this letter of understanding. Such definitive agreements shall be consistent with statutory requirements, appropriate environmental review by Bonneville and approval by the

Federal Energy Regulatory Commission. In the event either Party is unable to implement these principles hereunder, notwithstanding its best efforts to do so, this letter of understanding shall have no further force or effect.

Sincerely,

Senior Assistant Administrator

Name Edward W. Sienkiewicz
(Print/Type)

Date May 28, 1993

IT IS SO AGREED:

PACIFICORP

By

Name DENNIS P STEINBERG
(Print/Type)

Title Vice President

Date June 1, 1993

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