REDACTED
Rocky Mountain Power
Docket No. 20-035-04
Witness: David G. Webb

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

REDACTED
Direct Testimony of David G. Webb

May 2020

I. INTRODUCTION AND QUALIFICATIONS

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

A. My name is David G. Webb and my business address is 825 NE Multnomah Street, Suite 600, Portland, Oregon 97232. My title is Manager, Net Power Costs.

Q. Please describe your education and professional experience.

A. I received a Master of Accountancy degree from Southern Utah University in 1999 and a Bachelor of Science degree in Business Management from Brigham Young University in 1994. I am a Certified Public Accountant licensed in the state of Nevada. I have been employed by PacifiCorp since 2005 and have held various positions in the regulation, finance, fuels, and mining departments. I assumed my current role managing the regulatory net power cost group in 2019.

Q. Have you testified in previous regulatory proceedings?

A. Yes. I have previously provided testimony to the public utility commissions in Utah, Wyoming, Idaho, and Oregon.

II. SUMMARY AND PURPOSE OF TESTIMONY

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

A. The purpose of my testimony is to present the Company's proposed net power costs ("NPC") for the 12-month forecast period ending December 31, 2021 ("test period"). Specifically, my testimony:

- Summarizes forecasted NPC for the 2021 test period in this general rate case and explains the calculation of NPC using the Company's Generation and Regulation Initiative Decision Tools ("GRID") model;

- Describes several modeling changes the Company has made in order to improve the NPC forecast accuracy since the previous general rate case in Docket No. 13-035-184 ("2014 GRC");
- Explains the primary drivers behind the decrease in NPC compared to the current base NPC approved by the Public Service Commission of Utah ("Commission") and incorporated into customer rates in the 2014 GRC, that includes a discussion of the changes to the Company's resource portfolio since the last case;
- Discusses the Company's treatment of its participation in the Western Energy Imbalance Market ("EIM") and the expected incremental benefits relative to the NPC forecast produced by the GRID model;
- Explains and supports the Company's proposed change to the Energy Balancing Account ("EBA") to include production tax credits ("PTCs");
- Discusses the treatment of the Subscriber Solar program in this proceeding and in the EBA.

III. SUMMARY OF COMPANY NET POWER COSTS

Q. Please explain the components of the Company's NPC.

A. NPC are defined as the sum of fuel expenses, wholesale purchase power expenses and wheeling expenses, less wholesale sales revenue. The NPC forecast approved in this case becomes the base NPC used for comparison to actual NPC in a subsequent EBA filing.

Q. Please explain how the Company calculates NPC.

A. NPC are calculated for the forecast 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. GRID respects all system requirements and constraints and uses incremental pricing to dispatch the Company's generation units for a cost minimizing output where demand and supply are balanced.

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 many years. However, to improve the accuracy of the NPC forecast, the Company is proposing several modeling changes in this case.

Q. What GRID inputs were updated for this filing?

A. All inputs have been updated since the 2014 GRC, including system load, wholesale sales and purchase contracts for electricity, natural gas and wheeling, market prices for electricity and natural gas also known as the Official Forward Price Curve ("OFPC"), fuel expenses, transmission topology, and the characteristics and availability of the Company's generation facilities.

Q. What is the date of the OFPC the Company used for its forecast NPC?

A. The forecast NPC used the OFPC dated December 31, 2019.

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___(DGW-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. What are the proposed system-wide NPC for the test period?

A. The proposed NPC for the test period are $1.421 billion on a total-Company basis and $619.2 million on a Utah-allocated basis.

Q. Please generally describe the changes in NPC compared to the 2014 GRC.

A. The decrease in NPC is driven by lower coal fuel expense, lower purchased power expense, lower wheeling expense and increased zero-fuel cost renewable generation. The decrease is partially offset by a reduction in wholesale sales revenue and a small increase in natural gas fuel expense. Figure 1 below illustrates the total-Company change in NPC by category compared to the NPC approved in the 2014 GRC.

Figure 1

Net Power Cost Reconciliation

	($ millions)	**$/MWh**
UT GRC 2014	**$1,491**	**$25.26**
Increase/(Decrease) to NPC:		
Wholesale Sales Revenue	168	
Purchased Power Expense	(6)	
Coal Fuel Expense	(248)	
Natural Gas Fuel Expense	19	
Wheeling and Other Expense	(3)	
Total Increase/(Decrease) to NPC	**(70)**	
UT GRC 2020	**$1,421**	**$23.46**

As shown in Figure 1, total-Company NPC has decreased from $1,491 million to $1,421 million, which is $70 million (4.7 percent) lower than in the 2014 GRC. The price per megawatt-hour ("MWh") has decreased from $25.26/MWh to $23.46/MWh. Unless otherwise noted, references to NPC or various individual cost items throughout my testimony are stated in total-Company system amounts.

Q. Please explain the reduction in wholesale sales revenue.

A. The reduction in wholesale sales revenue is driven by lower wholesale sales volumes, which are 2,839 GWh lower than in the 2014 GRC. Wholesale sales revenue is $168.3 million lower than the 2014 GRC with the reduction coming from market transactions (represented in GRID as short-term firm, and system balancing sales) and the expiration or termination of several long-term wholesale sales contracts. The reduction in volume is coupled with lower average market prices forecast in the test period. The average market price of wholesale sales is $31.98/MWh, a 17 percent decrease over the average market sale price in the 2014 GRC, which was $38.69/MWh. Several long-term sales contracts have expired or been terminated since the 2014 GRC, which reduces the total-Company wholesale sales revenue by about $58.0 million. The wholesale sales contracts removed from NPC are:

- Los Angeles Department of Water and Power (2016);
- Utah Municipal Power Agency (2017);
- Shell 2013-2014 Sale (2014)
- Sacramento Municipal Utility District (2015); and
- Bonneville Power Administration ("BPA") wind sales contract (2019).[1]

The average sales price of long-term contracts is $24.85/MWh, compared to the average price in the 2014 GRC of $44.82/MWh.

Q. Why did purchased power expense decrease?

A. The decrease in purchased power expense is driven by a decrease in the volume of system balancing purchases as well as lower system balancing prices, offset by an

[1] The Company negotiated a termination of the Foote Creek I BPA power purchase agreement as discussed in Mr. Timothy J. Hemstreet's direct testimony.

increasing volume of long-term purchases, primarily in the form of purchases from qualified facilities ("QFs"). Market purchases (represented in GRID as short-term firm and system balancing purchases) in the current case have an average price of $17.14/MWh, while the 2014 GRC had an average price of $29.80/MWh—a drop of approximately 42 percent. The market purchase volume is 1,471 GWh lower than in the 2014 GRC on a total-Company basis.

This case also includes 10 new long-term contracts with an average price of $18.95/MWh, with the expiration of eight long-term contacts with an average price of $57.66/MWh.

Several new QFs have come online since the 2014 GRC. The total expense for power purchased from QFs increased by $173.6 million which is driven by an anticipated generation volume increase of 3,296 GWh compared to the 2014 GRC. The average price for QFs included in this case is $59.74/MWh, compared to the average price of QFs in the 2014 GRC of $69.79/MWh. The impact of this increase in QF expenses almost completely offsets the savings from the market purchases described above, resulting in a net decrease in purchased power expense of $6 million.

Q. Please explain the decrease in coal expense in the current proceeding.

A. Total-Company coal fuel expense is $248.2 million lower than the 2014 GRC due to lower coal generation volume, partially offset by higher coal prices. The lower coal fuel expense is driven in part by the closure of the Carbon power plant in April 2015 and Cholla Unit 4, which the Company is proposing to remove from service in December 2020. Excluding the impacts of the Carbon and Cholla Unit 4 power plants, coal generation is approximately 11,542 GWh or 29 percent, lower than the 2014 GRC.

The average coal generation price across PacifiCorp's generation fleet is $1.69/MWh higher than the average coal generation price from the 2014 GRC. The increase is driven by changes in third-party coal supply and rail contracts. I provide additional detail regarding the coal fuel expense later in my testimony.

Q. Please discuss the change in natural gas fuel expense compared to the 2014 GRC.

A. Total-Company natural gas fuel expense is $19.5 million higher than the natural gas fuel expense in the 2014 GRC. The increased natural gas fuel expense is primarily due to higher forecasted generation volume, partially offset by lower natural gas market prices. The average cost of natural gas generation decreased 48 percent from $39.73/MWh to $20.74/MWh in the current proceeding. This decrease is more than offset by higher natural gas generation volume. Generation from natural gas power plants is 7,374 GWh more than the 2014 GRC, more than double the amount from the 2014 GRC.

Q. Please describe the decrease in the wheeling and other expense category.

A. Expenses in this category are lower due to expiration of several legacy wheeling contracts with BPA and Idaho Power Company. This decrease is partially offset by an $8 million service fee charged by the California Independent System Operator ("CAISO") for grid management related to the new nodal pricing model being developed as a requirement of the 2020 inter-jurisdictional cost allocation agreement ("2020 Protocol").

Q. Please explain the changes to the Company's generation resources since the 2014 GRC.

A. There have been multiple changes to the Company's generation resources since the

2014 GRC. The following is a list of some of the major changes affecting NPC:

- *Cholla Unit 4 Termination* – Unit 4 of the Cholla power plant is expected to be removed from service in December 2020, and will not operate during the test period;
- *Naughton Unit 3 Gas Conversion* – Naughton Unit 3 is being converted from a coal-fired resource to a natural gas resource in 2020;
- *New Renewable Resources* – The Energy Vision 2020 Projects, other renewable projects (wind and solar), and power purchase agreements are expected to be online during the test period.

IV. MODELING CHANGES TO GRID

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

A. Yes. The Company has made various modifications to the GRID inputs in order to increase the accuracy of forecast NPC, including changes to the following items:

- Updated the scalar method for the OFPC;
- Updated the regulating reserve requirement based on the Flexible Reserve Study in the 2019 Integrated Resource Plan ("IRP");
- Included actual capacity factors for owned wind power plants and purchased wind power plants; and
- Developed a solar hourly profile consistent with the method used for the wind hourly profile.

- Implemented a day-ahead/real-time ("DA/RT") adjustment to reflect system balancing costs that are not fully reflected in the Company's forward price curve or modeled in GRID

Details supporting each modeling change are provided below.

Q. Why is the Company proposing changes to NPC modeling in this case?

A. An accurate NPC forecast is important to send appropriate price signals to customers so they can make informed decisions regarding their energy consumption. The modeling changes proposed in this case are necessary to either improve the accuracy of the forecasts or to recognize costs and benefits that have previously not been modeled in the Company's forecasts.

Updated Scalars to the Official Forward Price Curve

Q. Please briefly describe the hourly scalars and how they are applied to the OFPC the Company used in GRID.

A. Scalars are multipliers that are applied to the monthly prices from the OFPC to derive an hourly price profile. In other words, scalars give the monthly prices an hourly shape. These multipliers are unique for every hour in a month for a given day type (i.e., weekdays excluding holidays, Saturdays excluding holidays, and Sundays/holidays), and therefore yield hour-to-hour price variability that is consistent with historical price data. Scalars greater than one would result in an hourly price for a given day type that is higher than the monthly forward price, and scalars that are less than one would result in an hourly price for a given day type that is lower than the monthly forward price. For example, if the average market price during hour-ending 10 in May is $18/MWh, and the average market price during all hours in May is $20/MWh, then the scalar for hour-ending 10 in May would be 0.9 or 90 percent.[2] The hourly price profile that is a result of applying scalars to forward monthly prices yields hourly prices that, when averaged across a given month, precisely equal the forward monthly prices in the OFPC.

Q. Please explain the change to the hourly scalars used in this case.

A. To better reflect ongoing changes in power markets and to increase transparency, PacifiCorp is no longer using five years of historical hourly prices from PowerDex. Instead, PacifiCorp is using the CAISO day-ahead hourly market prices at California-Oregon Border ("COB") and Palo Verde ("PV") for the most recent 24-month period. The change in data inputs that determine the scalars does not, however, alter the application of the scalars as described above.

Q. What are the hourly market price shapes using the CAISO day-ahead hourly market prices mentioned above?

A. Figure 2 and Figure 3 compare the average hourly market price shapes using the scalars derived from historical PowerDex prices (green line) and the scalars derived from historical CAISO prices (red line). As seen in both Figure 2 and Figure 3, the hourly market price shape using the CAISO prices more closely matches the actual hourly day-ahead prices from 2019 for the COB and PV market hubs.

[2] $18/MWh divided by $20/MWh equals 0.9 or 90 percent.

Figure 2

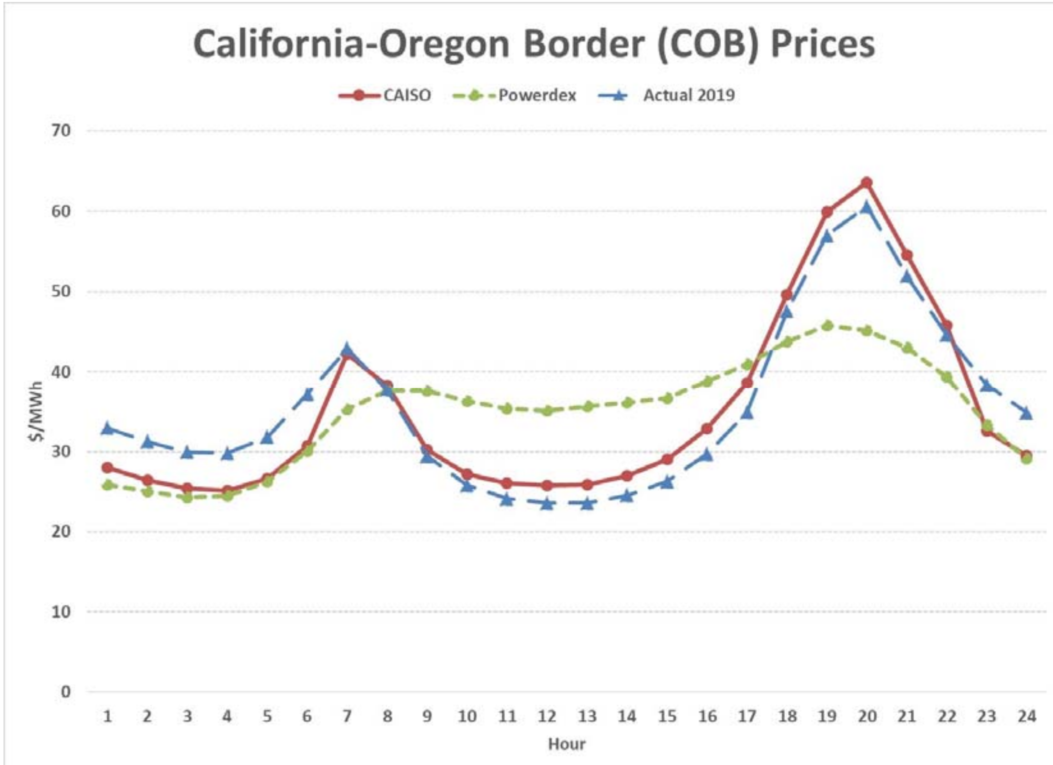
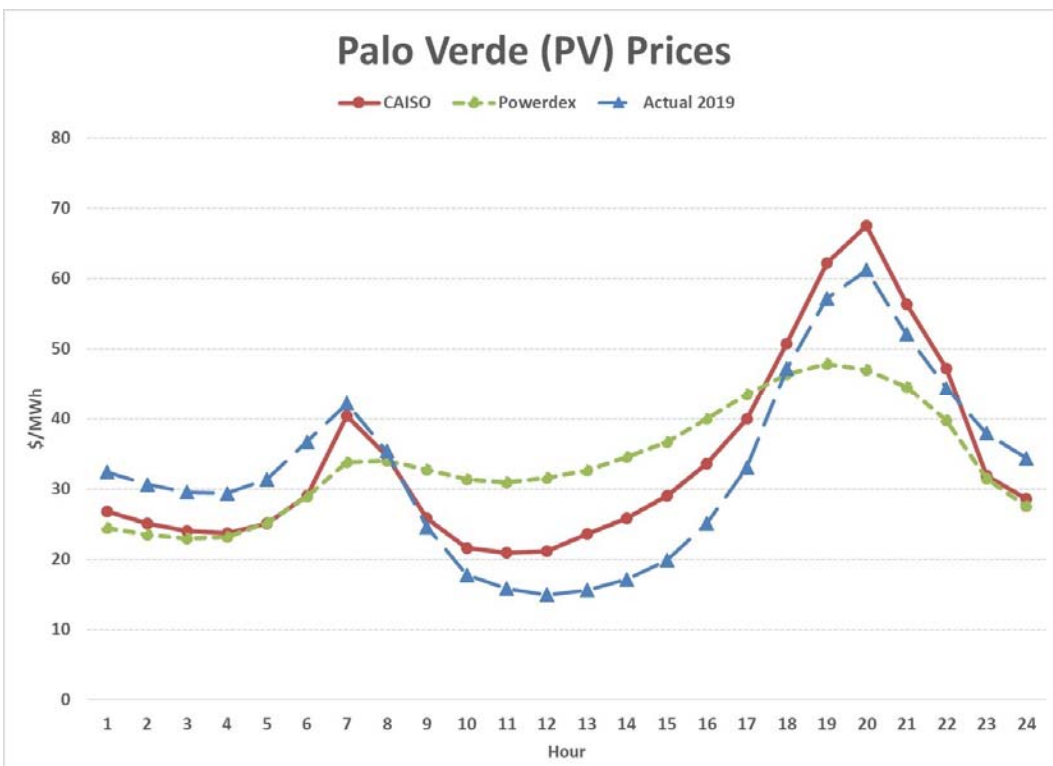


Figure 3



Q. Why is PacifiCorp making this change to its scalars?

A. As seen in the charts above, the updated scalars (red line) produce a more reasonable and accurate shape with a peak in the morning hours, depressed prices during mid-day, and larger peak in the evening hours. Comparing to the actual 2019 day-ahead hourly prices, the updated forecast scalars follow the actual hourly shape much better than the scalars based on the PowerDex prices. This type of shape is expected given the solar penetration in the West and is the result of higher quality CAISO trade data that better reflects actual and ongoing conditions in the power markets. The volume of actual trade data reported from CAISO is substantially higher than the volume of actual trade data that is reported in PowerDex. The use of the CAISO trade data results in scalars that better represent the increasing solar capacity in California and price volatility on a day-ahead basis. PowerDex is based on hour-ahead trade data. In 2019, only 4.3 percent of the Company's short-term firm transactions were hourly trades. Finally, the historical CAISO day-ahead hourly prices are publicly available resulting in greater transparency compared to the proprietary PowerDex prices.

Q. Why is the use of data from the most recent 24 months reasonable?

A. The scalars give the monthly prices an hourly shape and the most recent 24 months is indicative of the hourly shapes the Company expects to see in the markets in the future. Both PacifiCorp and the western interconnect as a whole have experienced a significant increase in the number of solar resources, including additional solar resources in the last 24 months, and this trend is expected to continue over the next several years.[3] This trend of increased solar resources has a meaningful impact on market price shape and

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[3] U.S. Energy Information Administration. Annual Energy Outlook 2017, Figures 58.19-58.22, *available at* https://www.eia.gov/outlooks/aeo/Figures_ref.php.

the former use of a five-year average dulls the impact of this trend. This effect can be seen in Figure 2 and Figure 3 above as the green line is much flatter. The figures show how the hourly shape of power prices over the past five years is not an accurate representation of the hourly shape expected in the future given the impact of solar resources. Additionally, using a more representative hourly pattern to provide a shape is consistent with how the Company shapes the wind generation and how the Company is proposing to shape the solar generation in this proceeding.

Q. Are there considerations in the calculations of hourly scalars for very high or very low price variations?

A. Yes. CAISO prices can vary widely, and the price shape for an hour and month can be skewed by the presence of a few very high or very low prices. Therefore, the CAISO prices used to calculate the hourly scalars are capped to limit the impact of potentially more extreme results. Large price variations are generally a result of unexpected conditions, which can include significant deviations from forecasted load, wind, or solar. Such deviations are largely random, so the presence of extreme values is generally a chance occurrence, rather than a characteristic of a given hour. Therefore, the CAISO prices used to calculate the scalars are capped at +$250/MWh and -$50/MWh. The price cap balances the evidence that extreme events did occur in particular hours, with the likelihood that such events could occur in any hour.

Additionally, as the historical monthly prices approach zero, the magnitude of the shaping becomes unrealistically large. When this happens, the historical prices are uniformly shifted until the average monthly price over the calculation period is

$25/MWh, at which point, the scalars are calculated based on the adjusted historical prices resulting in a more reasonable shape.

Q. What is the NPC impact of the change to the scalars?

A. This change increased total-Company NPC by $4.3 million.

Regulating Reserve Requirement

Q. How did PacifiCorp update its regulating reserve requirement modeling?

A. The Company's regulating reserve requirements are now based on the 2019 Flexible Reserve Study ("2019 FRS") that was submitted as part of the development of the 2019 IRP.[4]

Q. How has the modeling of regulating reserve requirement changed as a result of the 2019 FRS?

A. The Company included several modeling changes compared to the 2014 Wind Integration Study ("WIS") that was used in the 2014 GRC:[5]

- The regulating reserve requirement is a function of a specific value that is fixed in all hours and a variable regulation reserve requirement that is based on the change in the resource balance from hour to hour.
- The regulating reserve requirement varies when wind and solar generation changes. The load and non-variable energy resource ("VER") variables have fixed amount of regulation reserve requirements. VERs refer to variable energy resources, which: (1) are renewable; (2) cannot be stored by the facility owner or operator; and (3) have variability that is beyond the control of the facility owner or operator.

[4] 2019 Integrated Resource Plan, Volume II at Appendix F, Docket No. 19-035-02.

[5] The system impact to NPC from the change of using the 2014 WIS to the 2019 FRS is difficult to quantify due to the many changes to the Company's system since the 2014 GRC. Various generation resources have been added and removed from the system which affects how the regulating reserves studies are prepared and applied to NPC.

- A unit can be allocated reserves up to the lesser of its 30-minute ramp rate and the difference between its minimum and maximum operating levels. If a unit is allocated reserves, the allocated capacity is subtracted from the unit's maximum operating level, resulting in a reduced maximum dispatch level.
- The 2014 WIS included EIM diversity benefits associated with transfers between PacifiCorp's west balancing authority area and CAISO. Since then, a number of additional utilities have joined EIM, and diversity benefits have increased. After accounting for EIM diversity benefits, the 2014 WIS identified a total regulation requirement of approximately 561 MW to integrate load and wind. The 2019 FRS identified a total regulation requirement of 531 MW to integrate load, wind and solar.

For additional details, please refer to the Company's regulating reserve requirements based on the 2019 Flexible Reserve Study that was included in the 2019 IRP.

Actual Capacity Factor for Owned Wind Generation and Purchased Wind Generation

Q. Please describe the adjustment made to the forecast capacity factor for Company-owned wind generation and purchased wind generation.

A. Previously, the generation from PacifiCorp's owned wind power plants and purchased wind was based on long-range forecasts provided to the Company by the project developers. In this case, PacifiCorp proposes to calculate the annual capacity factor using a cumulative average methodology for any wind power plants with a history longer than four years. For those projects with less than four years of history, the project developer's forecast is used until four years of actual results become available at which point, actual historical data is then used.

Actual wind generation at these facilities has varied somewhat from developer forecasts, so to better align forecasted NPC with actual results, the Company modeled the forecasted wind generation for each wind plant to match the levels in the cumulative historical period. This change brings the modeling of wind plants in line with the historical actuals, which will better reflect a reasonable level of generation for the future period.

Q. With the increasing renewable generation on the Company system, does the Company plan to use the historical average method for the forecasted capacity factor for its owned and purchased solar resources?

A. Yes. Currently, the Company uses the long-range forecasts provided by the project developers for all owned and purchased solar resources since they have been on the Company's system for less than a four-year period. The Company proposes to switch to the annual capacity factor using a cumulative average methodology for any solar power plants with a history of longer than four years.

Q. What is the impact of using the cumulative historical generation rather than the project developers' forecast?

A. In this case, reflecting the generation output as described above decreases total-Company NPC by approximately $1.1 million.

Solar Hourly Shape

Q. Please explain how the Company used historical solar output to calculate the solar generation shape in this case.

A. In this case, the Company continues to use the P50[6] forecast approach for determining total solar generation, and used the Company's actual 2019 energy output data from its purchased solar facilities to shape hourly solar generation profiles. The Company scaled actual generation levels up or down so that, when the output 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 solar facilities is the same as the P50 forecast used in previous cases, but the shape of the generation varies on an hourly basis consistent with actual output during 2019. This method is consistent with the wind hourly shape method used by the Company in the 2014 GRC.

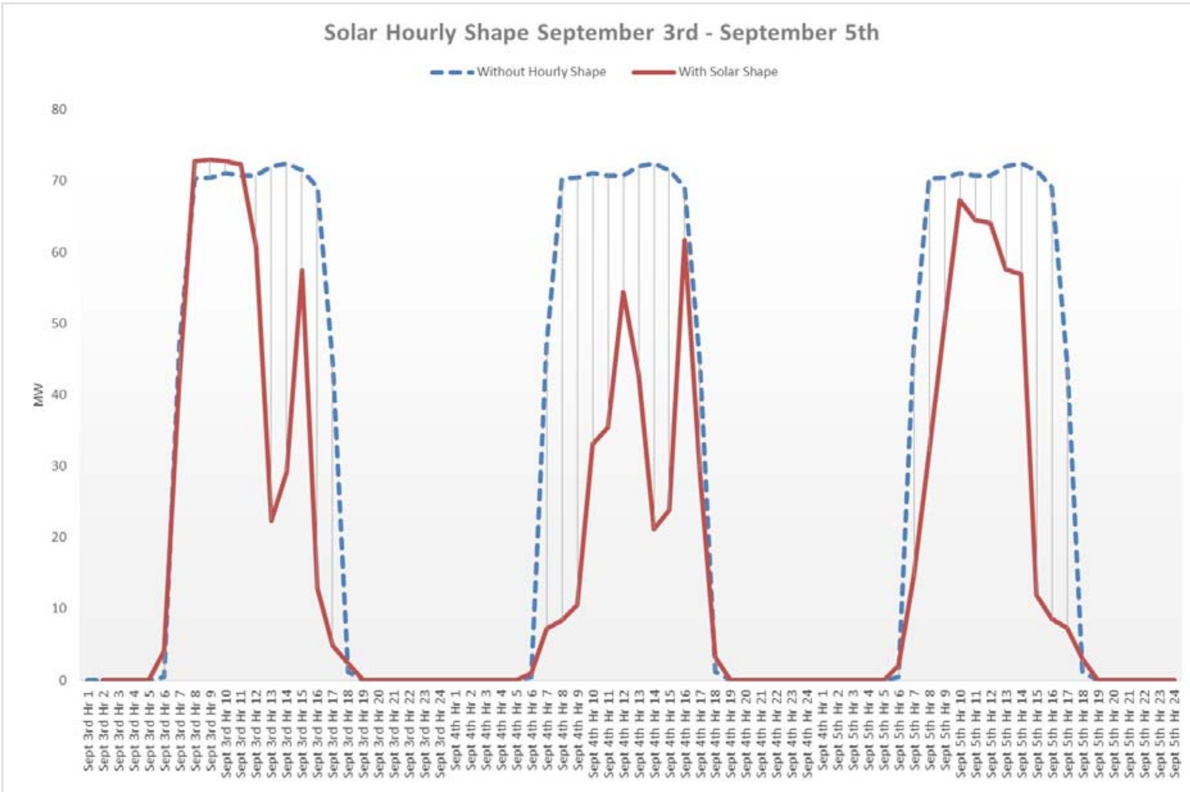
Q. Why did the Company choose to use the hourly solar profile to reflect historical performance?

A. Figure 4 illustrates the difference in solar generation profiles. The solid line shows one solar plant's hourly energy shape on the dates September 3rd to September 5th in this case. The dashed line shows the solar hourly shape for the same dates without hourly shaping. The shaded area shows the difference between the two hourly shapes and represents the difference in solar generation for that day. The dashed line does not have any day-to-day variation in each month. The solid line better represents the solar inputs

[6] A P50 forecast projects generation at a level that is expected to have an equal probability of being higher or lower than forecast. Typically such a forecast is developed for an individual project by combining solar exposure taken before the project is constructed with a detailed plant location and performance characteristics. The projected output in a given month is then averaged across a given month to produce a 12 x 24 matrix of average hourly output.

that vary hourly based on historical volatility, with the same total monthly solar generation volume as the P50 forecast.

Figure 4



Day-Ahead and Real-Time Balancing Transactions

Q. Please summarize the Company's proposal to more accurately model system balancing transactions in GRID NPC.

A. To more accurately model system balancing transactions, the Company adjusted forward market prices to reflect historical variations from average actual market prices for purchases and sales. The Company also adjusted system balancing transaction volume to reflect transacting on a forward basis using standard block products, balanced on an hourly basis in the real-time markets.

Q. Please explain how the GRID model currently balances load and resources on an hourly basis.

A. The GRID model calculates the least-cost solution to balance the Company's load and resources to fractions of a MW for each hour. The model makes purchases in the wholesale market (labeled as "system balancing purchases" in the NPC report) in the hours for which the Company does not have enough owned or contracted resources to meet its load. The model also makes wholesale market sales (labeled as "system balancing sales" in the NPC report) when it has excess resources for a given hour. These system balancing transactions are calculated for each hour independently and are for the precise volume required by the model. The model assumes execution in a single perfectly balanced step. Wholesale market prices for the system balancing sales are based on an hourly forward price curve that is developed from monthly HLH and LLH prices with hourly scalars applied. These scalars are identical within a given month for each weekday of that month. The prices are input into the model and do not change based on the volume of the system balancing transactions.

Q. How do actual operations differ from the GRID model logic?

A. In actual operations, the Company continually balances its market position first with monthly products, then with daily products, and finally with hourly products, in contrast to the single perfect balancing step described above. The monthly and daily position is calculated as the average for the respective time horizon during HLH and LLH periods; for example, the average hourly HLH position during the month of January, or the average hourly LLH position on a given day in February. The monthly and daily products utilized to balance the Company's position in the wholesale market are available in flat 25 MW blocks. The Company's load and resource balance, however, varies continuously each hour in quantities that may vary widely from a flat 25 MW block. In real-time operations, the Company balances its hourly position in the hourly real-time market. At that point, the Company must transact to maintain a balanced system and, as a result, becomes a price-taker subject to whatever price is available at the time.

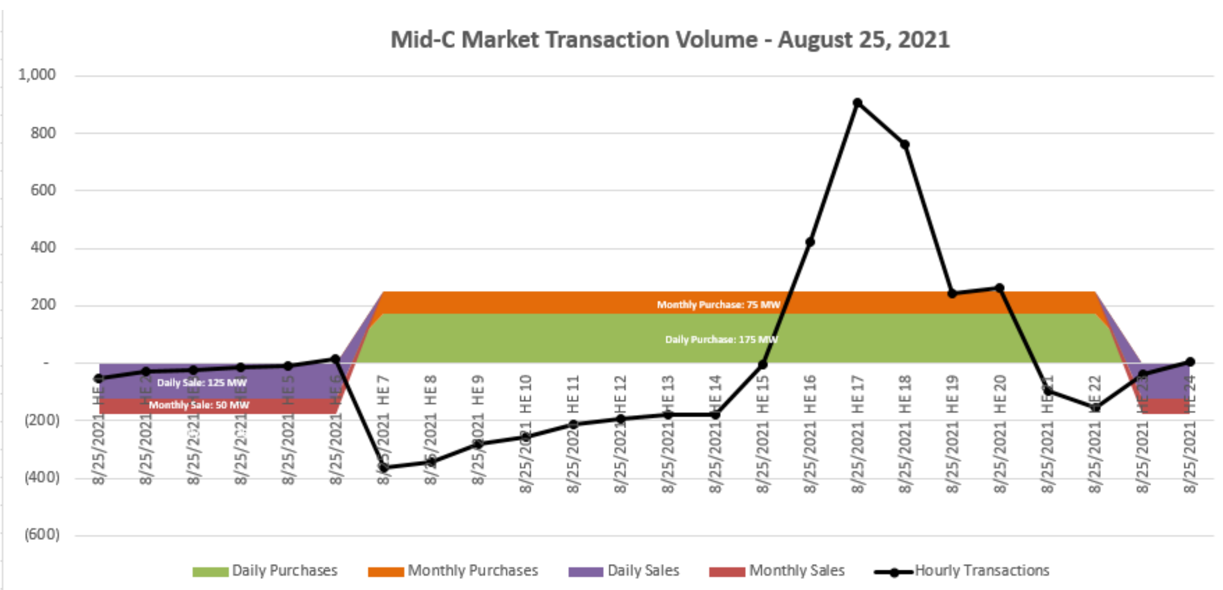
Q. How do the system balancing volumes in GRID compare to the Company's actual volumes?

A. The volume of system balancing transactions generated by GRID is smaller than the volume of similar transactions in actual results. Because GRID balances the Company's load and resources to fractions of a MW for each hour in a single step, it avoids the additional purchase and sale transactions that occur in actual operations as the Company progresses through balancing its system on a monthly, daily, and real-time system basis.

For instance, when the Company buys a monthly product that aligns with the Company's average open position for the month, one can expect that roughly half of the days will still have a remaining position to be covered by additional daily purchases. On the other days, the Company will have to make daily sales to unwind the excess volume. The same is true for daily transactions—in some hours the volume acquired will be too low, while in others it will be too high, and additional purchases and sales will be required to cover the Company's actual position.

In addition, buying or selling standard block products for monthly and daily average requirements will not result in a perfect balance of load and resources. This difference then must be closed out in the real-time market where the Company is a price-taker. Figure 5 below illustrates this effect for transactions at the Mid-C market hub during a sample day in the NPC forecast. The solid line represents the hourly sales and purchases generated by the GRID model, and the shaded areas represent monthly and daily standard block products.

Figure 5



Q. Please describe the difference between the hourly price forecast used in GRID and the actual prices for day-ahead and real-time transactions.

A. The GRID model uses an hourly forward price curve that is developed from monthly HLH and LLH prices with hourly scalars applied. These scalars are identical within a given month for each weekday of that month. In reality, prices vary within each month, and the Company has historically bought more during higher than average price periods in each month, and sold more during lower than average price periods. As a result, the average cost of the Company's daily and hourly short term firm purchases has been consistently higher than the average actual monthly market price, while the average revenues from its daily and hourly short term firm sales has been consistently lower than the average actual monthly market price.

Q. Is some of the unfavorable price impact already reflected in GRID due to the hourly price scalars?

A. Yes. However, the hourly scalars only capture the costs associated with the Company buying more in the highest load hours around the daily peak, and less in the shoulder hours when loads are well below the peak. They do not capture the impact of buying more on the highest cost days in a month, and selling more on the lowest cost days, since every weekday has the same prices.

Q. How does the Company propose to capture the cost of day-ahead and real-time balancing transactions in the NPC forecast for the test period?

A. To better reflect the market prices available to the Company when it has volumes to transact in the real-time market, the Company has included in GRID separate prices for purchases and sales. These prices are adjusted to account for the historical price differences between the Company's purchases and sales compared to the average market prices. For instance, the Mid-Columbia HLH price in January is increased by $2.21/MWh for purchases and decreased by $1.39/MWh for sales.

The price adjustment does not need to be positive for purchases and negative for sales. For instance, the Mid-Columbia LLH price in April is increased by $1.58/MWh for purchases, but is also increased by $1.14/MWh for sales. Thus sales at Mid-Columbia in light load hours in August result in incremental revenue compared with the average market prices, reducing NPC.

As described above, in some periods the Company's average purchase costs were lower than its average sales prices. If the inputs to the GRID model for a single market showed a purchase price that was less than the sales price, then the GRID model would buy and sell arbitrarily large volumes of power under this situation. In reality the volumes in question were very limited. To prevent this, when the average monthly sales price exceeds the monthly purchase price in the same market, a single price adjustment is used for both sales and purchases based on the volume-weighted average of the historical sales and purchases.

Q. Have you also calculated a forecast of additional purchase and sale volumes that arise from using monthly, daily, and hourly products to meet the balancing position determined by GRID?

A. Yes. The system balancing sales volume determined by GRID would need to be increased by 1.6 million MWh, or roughly 31.7 percent, to account for the use of monthly, daily, and hourly products. System balancing purchase volume would be increased by an equal and offsetting amount as the net position determined by GRID is unchanged.

Q. Have these additional volumes been included in the test period NPC forecast?

A. Yes. The Company has added to its NPC forecast the incremental balancing volumes associated with using standard products to cover the open position determined by GRID. These volumes are priced such that the overall cost of the Company's day-ahead and real-time balancing transactions relative to the forecasted monthly market prices is equal to the historical average.

Q. What is the impact to NPC when GRID is adjusted to reflect the historical impact of day-ahead and real-time balancing transactions?

A. When the adjustments to reflect the impact of historical day-ahead and real-time transactions are included in GRID, total-Company NPC increased by approximately $43.7 million in the case.

Q. How does the resulting short term purchase volume in the Company's forecast compare to the historical level?

A. The Company's forecast includes 3.5 million MWh of short term wholesale market purchases, whereas the Company's 48 month average is 3.3 million MWh per year. In actual operations, the Company's net position is a forecast, and varies over time with changes in forecasts of load, wind, hydro, unit outages, and the economics of the Company's thermal fleet compared with market. As these forecasts change, the Company will buy and sell to limit or cover its revised open position.

V. SUMMARY OF COMPANY COAL COSTS

Q. How does PacifiCorp plan to meet fuel supplies for its coal power plants in 2021?

A. PacifiCorp employs a diversified coal supply strategy, with 81 percent of its 2021 coal requirements supplied by third-party coal supplies and 19 percent with coal from its captive affiliate mines. The third-party contracts consist of fixed-price and variable-priced contracts. Coal amounts in my testimony are shown on a total-Company basis.

Jim Bridger

Q. Please describe the coal supply arrangement for the Jim Bridger power plant for 2021.

A. The Jim Bridger power plant is supplied by the Company-owned Bridger Coal

Company ("BCC") mine and the Black Butte mine in the test period.

Q. Please describe the change in BCC costs in this case.

A. BCC costs in this case are forecast to be [redacted] million higher than the 2014 GRC. The cost for the BCC deliveries increases by [redacted] per ton, from [redacted] per ton in the 2014 GRC to [redacted] per ton in this case. The test period includes the delivery of [redacted] million tons which is [redacted] million tons less than in the 2014 GRC. The tonnage reduction is primarily due to the reduction in coal consumption forecasted for Jim Bridger at a cost of [redacted] million, [redacted] million for final reclamation contributions and [redacted] million for other miscellaneous costs, partially offset by a decrease of [redacted] million for coal inventory, and a [redacted] million decrease due to improved heat content of the delivered coal.

Q. What is the expected change in third-party coal prices for the Jim Bridger power plant in this case?

A. Delivered costs for the [redacted] million tons of Black Butte coal increased from [redacted] per ton in the 2014 GRC to [redacted] per ton in this case, or [redacted] million overall. The price of Black Butte coal increased [redacted] per ton, from a cost of [redacted] per ton in the 2014 GRC to [redacted] per ton in this case. The coal price increase is approximately [redacted] million, or [redacted] percent. The Union Pacific Railroad agreement is forecast to increase by [redacted] million in delivered costs. These increases are primarily due to inflation.

Naughton

Q. Please describe the coal supply arrangement for the Naughton power plant in 2021.

A. The Naughton power plant is supplied by the adjacent Kemmerer mine under a long-term coal supply agreement ("CSA") through 2021. The CSA contains an environmental response provision to reduce the minimum annual tonnage volume quantity in the event of a reduction in coal-fired generation at the plant due to changes in environmental laws or rules.

As a result of Naughton Unit 3 converting from a coal-fired to a natural gas-fired resource,[7] PacifiCorp exercised the environmental provision in the CSA and the annual minimum take-or-pay quantity was reduced from [redacted] million tons to [redacted] million tons. In lieu of a full take-or-pay payment of approximately [redacted] per ton or [redacted] million for the [redacted] million tonnage decrease, an environmental shortfall payment of [redacted] million, will be owed in 2021. The environmental shortfall payment is a direct result of the reduction in the coal purchases due to Naughton Unit 3 discontinuing as a coal-fired unit.

Q. Please describe the Naughton power plant's coal cost change from the 2014 GRC.

A. Total delivered coal cost at Naughton increased [redacted] per ton, from [redacted] per ton in the 2014 GRC to [redacted] per ton in this case resulting in an overall increase of [redacted] million. The 2021 price forecast is based upon the 2019 price reopener with escalations based upon projected diesel fuel prices and other price indices. The contract escalation results in a price increase of [redacted] million after royalties and taxes. Another driver of

[7] As discussed in the direct testimony of Mr. Robert Van Engelenhoven in this case.

the price increase is the [redacted] million environmental shortfall payment in 2021. The change in the amount of coal purchased under each price tier—namely less lower-priced tier-2 coal—increases costs by [redacted] million. The forecasted tier-2 coal delivered in calendar year 2021 is [redacted] tons less than the 2014 GRC. The increase in coal costs is partially offset by a reduction of [redacted] million for contract amortization costs. The amortization of these costs were completed at the end of 2016.

Wyodak

Q. Please describe the price increase related to the Wyodak power plant contract.

A. Delivered coal cost increased from [redacted] per ton in the 2014 GRC to [redacted] per ton in this case, or [redacted] million overall. The cost increase is primarily the result of escalation in diesel fuel and other contract indices.

Dave Johnston

Q. Please describe the Dave Johnston power plant coal supply cost increase.

A. Dave Johnston power plant delivered coal cost decreased by [redacted] million compared to the 2014 GRC, or [redacted] percent. The reduction is due to a decrease in coal costs of [redacted] million, as described in further detail below, partially offset by an increase in rail costs of approximately [redacted] million.

Q. Please describe the open coal position for the Dave Johnston power plant in 2021.

A. The Dave Johnston power plant is projected to consume approximately [redacted] million tons in 2021; the Company currently has [redacted] million tons of coal under contract for the plant resulting in an unidentified or open position of [redacted] million tons. The Company will solicit coal supplies from Powder River Basin ("PRB") mines through a request for proposals during 2020 to fill a reasonable portion of the open position, which may be adjusted according to market conditions. The Company has used this fueling strategy for the Dave Johnston power plant for several years.

Q. What are the coal supply arrangements for the Dave Johnston power plant in this case?

A. Arch Coal's Coal Creek mine will supply [redacted] million tons and Peabody Energy's Caballo mine will supply [redacted] million tons in 2021 ([redacted] percent of the plant's requirements). The coal price for the Dave Johnston power plant's open position of approximately [redacted] million tons in this case reflects the average 2021 forward price for PRB 8400 British thermal units ("Btu") coal of [redacted] per ton, as published in Energy Ventures Analysis Fuelcast in November 2019. The 2021 price is lower than the 2014 PRB 8400 Btu price of [redacted] per ton that was used for the open position in the 2014 GRC. The coal cost decrease of [redacted] million is the aggregate of a decrease to coal costs of [redacted] million for refined coal, partially offset by an increase to the cost of coal of [redacted] million. The rail cost increase of [redacted] million is primarily a result of inflation partially offset by a shorter rail distance for the spot coal purchases compared to the Dry Fork mine location, which is further from the Dave Johnston power plant.

Hunter

Q. Please explain how the Company's Hunter power plant is supplied with coal in this case.

A. Historically, the primary coal supply for the Hunter power plant has been provided through a CSA with Wolverine Fuels, LLC ("Wolverine") formerly known as Bowie Resource Partners that expires December 31, 2020. For this case, the pricing for coal costs is based upon a market forward price for Utah coal, as published in Energy Ventures Analysis Fuelcast in November 2019.

Q. Please describe the change in coal costs at the Hunter power plant in this case.

A. Coal prices have decreased [redacted] per ton, from [redacted] per ton in the 2014 GRC to [redacted] per ton in this case ([redacted] million overall). The decrease is primarily due to the estimated price for the new CSA(s) beginning in 2021 for a decrease of [redacted] million, [redacted] million for refined coal and a decrease to Energy West costs of [redacted] million, partially offset by increases of [redacted] million for the Energy West pension costs, [redacted] million for the expiring Wolverine agreement, and [redacted] million for the expiring Westridge agreement.

Huntington

Q. Please describe the coal supply arrangement for the Huntington power plant in 2021.

A. The primary coal supply to the Huntington power plant is provided through a requirements CSA with Wolverine. This is a "delivered to the plant" agreement with Wolverine responsible for transportation of the coal from the sourced mines to the plant, although PacifiCorp is responsible for limited trucking cost escalation. In the 2014 GRC, the Huntington power plant also received coal under a CSA with Rhino Energy, LLC's Castle Valley mine. That CSA ends December 31, 2020.

Q. What coal supply costs for the Huntington power plant are included in this case?

A. For the Huntington power plant, delivered coal prices increased from [redacted] per ton in the 2014 GRC to [redacted] per ton in this case, an overall increase of [redacted] per ton or [redacted] million. The overall price per ton for the Wolverine contract increased [redacted] per ton, from [redacted] per ton in the 2014 GRC to [redacted] per ton in this case, [redacted] million overall on [redacted] million tons. The increase is due to contractual price changes and escalation associated with transportation costs.

Q. Does the current proceeding reflect Energy West pension costs?

A. Yes. This proceeding includes [redacted] million, PacifiCorp share, for contributions to the 1974 United Mine Workers Association pension plan.[8] [redacted] million of the pension cost is included in the Huntington plant fuel costs, and [redacted] million, is included in the Hunter plant fuel costs in this case.

Cholla

Q. Please describe the coal supply arrangement for the Cholla power plant.

A. PacifiCorp exercised a provision in the CSA with Peabody Energy's Lee Ranch/El Segundo mine complex to terminate the contract at the end of 2020. Due to the termination of the CSA and closure of Unit 4 at the Cholla power plant at the end of 2020, there are no coal fuel expenses associated with Cholla in this case.

Craig

Q. Please describe the coal supply arrangements for the Craig power plant.

A. In 2021, the Craig power plant will be supplied by the Trapper mine, which is an affiliate captive mine owned by four of the five Craig power plant owners. PacifiCorp's share of the mine is 21.4 percent. The pricing under the CSA is based upon the annual mine cost associated with the Trapper mine.

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[8] *In the Matter of PacifiCorp d/b/a Rocky Mountain Power Application for Approval of the Transaction for Closure of Deer Creek Mine and a Deferred Accounting Order*, Docket No. 20000-464-EA-14 (Record No. 14041) (May 15, 2015).

Q. Have coal costs changed from the 2014 GRC?

A. Yes. For the Craig power plant, delivered coal prices increased from [redacted] per ton in the 2014 GRC to [redacted] per ton in this case, an overall increase of [redacted] per ton or [redacted] million. Trapper mine costs have increased [redacted] per ton, from [redacted] per ton in the 2014 GRC to [redacted] per ton in this case, a [redacted] million overall price increase. The price increase is due to reduced volume from the Trapper mine and increases to overall mining costs at the Trapper mine.

The Colowyo CSA expired at the end of 2017. In the 2014 GRC, the Colowyo mine was projected to deliver [redacted] tons of coal annually to the Craig plant. The expiration of the Colowyo mine CSA decreased the coal costs at the Craig plant by [redacted] million, as the Trapper mine has a lower cost than the expired Colowyo CSA.

Hayden

Q. Please describe the change in Hayden power plant's coal cost from the 2014 GRC.

A. Delivered coal prices increased [redacted] per ton, from [redacted] per ton in the 2014 GRC to [redacted] per ton in this case. Under the terms of the January 1, 2018 reopener provision, the coal price was lowered and adjusts on a fixed annual schedule from 2018 to 2022.

Colstrip

Q. Please describe the change in coal cost at the Colstrip power plant in this case.

A. Delivered coal prices increased [redacted] per ton, from [redacted] per ton in the 2014 GRC to [redacted] per ton in this case, an increase of [redacted] million. PacifiCorp based the costs for the Colstrip power plant on the new CSA that was signed December 5, 2019. The CSA has changed from a [redacted].

Q. Please summarize how the changes to the coal fuel expenses described in this section affected NPC in this case.

A. Customers have benefited from the Company's diversified fueling strategy, which relies upon fixed-price contracts, index-priced contracts, and affiliate-owned mines to meet the fuel needs of its coal-fired power plants. Several factors have contributed to the $248 million decrease in coal-fuel expense in this filing, primarily reduced coal volumes. PacifiCorp's fueling strategy has resulted in long-term, stable, coal supplies for its customers.

VI. CUSTOMER BENEFITS OF THE ENERGY IMBALANCE MARKET

Q. Please describe the EIM and the Company's participation in the EIM.

A. The EIM is a real-time balancing market that optimizes generator dispatch every five and 15 minutes within and among PacifiCorp, the CAISO and other EIM participants. Through the EIM, the Company's participating generation units are optimally scheduled and dispatched using the CAISO's security constrained unit optimization and economic dispatch models. The EIM's automated, expanded footprint and co-optimized dispatch replaced the Company's isolated and manual dispatch within its two balancing authority areas ("BAAs"). Participation in the EIM benefits customers by reducing NPC, with relatively low ongoing operation costs.

Q. Has the EIM continued to provide customer benefits since the 2014 GRC?

A. Yes. The Company has participated in the EIM since 2014. The EIM has continued to provide benefits to customers through more efficient and economical dispatch, inter-regional transfers (i.e., exports and imports between EIM participants), reduced reserve requirements, and greenhouse gas ("GHG") revenue. Each year the benefits have increased as regional participation in the inter-regional markets has increased.

Q. Are new EIM entrants in 2020 and 2021 projected to substantially impact PacifiCorp's forecasted EIM inter-regional transfer benefits?

A. No. The EIM footprint currently encompasses approximately 60 percent of Western Electricity Coordinating Council load including CAISO (2014), PacifiCorp (2014), NV Energy (2015), Arizona Public Service (2016), Puget Sound (2016), Portland General Electric (2017), Powerex (2018), Idaho Power (2018) and Balancing Authority of Northern California phase 1 (2019). The entities joining the EIM in 2020 and 2021 will not increase this percentage substantially. More importantly, the new entrants bring little to no transmission connectivity between themselves and PacifiCorp. With these combined factors, the projected impact to PacifiCorp's EIM transfer benefits is expected to be minimal.

Q. Please summarize the EIM benefits included in this case.

A. The NPC forecast from GRID includes an adjustment to reflect incremental EIM benefits from inter-regional dispatch reduced flexibility reserves, and GHG revenue. Specifically, the NPC forecast includes approximately [redacted] million in EIM benefits and [redacted] million in GHG revenue. In this case, the Company's share of the reserve benefit based on the diversified footprint of the EIM is explicitly accounted for and the regulating reserve requirement is reduced by approximately 104 MW.[9]

Q. What are the EIM inter-regional transfer benefits?

A. The inter-regional transfer benefits reflect the benefits received by PacifiCorp when it

[9] 2019_IRP_Volume_II_Appendices_A-L.pdf, Appendix F, pages 101 - 102 Appendices_A-L.pdf, Appendix F, pages 101 - 102. Docket No. 19-035-02.

economically exports energy to the EIM and when it economically imports energy from the EIM which allows displacement of a more expensive resource on the Company system. Generally, the benefit of EIM exports is equal to the revenue received less the production cost of generation assumed to supply the transfer. The production cost used in the Company's calculation of EIM benefits is the marginal cost to produce an additional MWh at a given resource. The Company's production costs used to calculate EIM benefits are equal to the resource bids submitted to the EIM. The benefit of EIM imports is equal to the import expense less the avoided expense of the generation that would have otherwise been dispatched.

Q. How does the Company calculate the inter-regional dispatch EIM benefits forecast?

A. The Company uses historical actual EIM inter-regional transfer benefits in statistical models to forecast EIM transfer benefits as a function of market prices and transfer volume inputs, which are the underlying drivers of actual EIM transfer benefits. The price inputs are the energy and natural gas market prices from the OFPC. The transfer volume inputs are the total transfer capacity of transmission along with spring oversupply conditions, based on the current and expected solar capacity in California. This market fundamentals approach to forecasting EIM transfer benefits mimics the method which the Company uses to calculate actual EIM transfer benefits and maintains consistency with the bilateral market price inputs that drive the Company's GRID forecasted NPC. By utilizing the same inputs, the forecast of EIM inter-regional transfer benefits, the calculation of actual EIM inter-regional transfer benefits, and the GRID forecasted NPC are aligned and produce a reasonable forecast of EIM inter-regional transfer benefits. The regression modeling for this rate case is a method which provides the comprehensive view from all the variables actually impacting inter-regional EIM benefits in the future. When the EIM market stabilizes as new participant growth slows, the regression modeling creates a robust and accurate view of the future.

Q. How does the Company calculate the EIM GHG benefits?

A. GHG benefits are realized when the GHG revenue is higher than the Company's resulting compliance cost. GHG revenues are received from the energy dispatched to serve the CAISO's GHG obligations and the associated payment for GHG compliance costs which is embedded within the EIM price as the marginal cost of GHG. The Company's compliance cost is the expenditure to procure the necessary California Carbon Allowances for the portion of the energy dispatched to serve the CAISO's GHG obligations.

VII. PRODUCTION TAX CREDITS IN CUSTOMER RATES

Q. What are PTCs and how are they included in customer's rates?

A. The generation of energy at certain company-owned facilities is eligible for the renewable electricity PTCs, and the credit is included as an offset to the Company's federal income taxes. For each kilowatt-hour of energy generated at eligible wind-powered generating facilities, the Company receives a $0.025 credit on its tax return, for a duration of 10 years beginning on the date which the facility became commercially operational. The value of these credits is reflected as a reduction to current income tax expense on the financial statements and for rate-making purposes.

The amount of renewable electricity PTCs received is dependent on the amount of generation at eligible facilities, and the forecasted generation of these facilities included in NPC is the same output currently used to calculate the value of the renewable electricity PTCs in a GRC. To the extent the generation from these plants varies from the forecast, the impact on NPC is updated via the EBA filings, but the PTC impact is not currently trued-up.

Q. Please explain the Company's proposal to include PTCs in the EBA.

A. Although PTCs are not currently included in NPC, it is logical to treat PTCs similarly for ratemaking purposes since they are tied to generation. As PacifiCorp completes the Energy Vision 2020 projects, leading to new renewable and repowered renewable resources on the system, the PTCs associated with these projects represent a significant source of additional value for customers. PacifiCorp's proposal to track and true-up PTCs through the EBA is designed to pass back to customers the full and actual value of PTCs.

Q. Why is it appropriate to start including PTCs in the EBA now?

A. PTCs are only available during the first 10 years of an eligible resource's life. PacifiCorp's existing wind fleet was repowered in 2019 or is being repowered in 2020 and will therefore requalify for PTCs. Additionally the new Company-owned wind resources that will come online at the end of 2020 will also qualify for PTCs. Updating the EBA to include PTCs will allow customers to receive the full PTC benefits from the new eligible resources.

Q. Is the Company's proposed treatment of PTCs in the public interest?

A. Yes. The customer will be able to receive the actual benefits from PTCs.

Q. What is the current level of PTCs included in rates?

A. As shown in Mr. Steven R. McDougal's Exhibit RMP___(SRM-3), Page 7.5.3, this case includes approximately $193.5 million of total-system PTCs.

VII. SUBSCRIBER SOLAR

Q. Please describe the current Subscriber Solar program and how it is treated in the EBA.

A. The current Subscriber Solar program is served by a single PPA that is situs allocated to Utah customers. Subscriber Solar customers pay the PPA price and receive a credit in their rates for the value of the energy equal to the avoided costs. An NPC adjustment is included in this case that situs assigns the portion of the PPA that is over the market value to Utah. This adjustment will be included in the future EBA filings consistent with how it is included in this case.

Q. How will the expanded Subscriber Solar program proposed in the testimony of Mr. William J. Comeau be treated in the EBA?

A. The new resource for the expanded Subscriber Solar program will generally be treated the same as the current Utah subscriber solar program once it is commercially operational. The only exception will be that the PPA and any credit for the value of the energy produced by the Subscriber solar resource will also be situs assigned to Utah customers in NPC and the EBA.

VIII. CONCLUSION

Q. Please summarize your direct testimony.

A. The Company's NPC for the 2021 test period in this case have decreased by $70 million on a total-Company basis, almost five percent, since the 2014 GRC. This reduction is largely driven by reductions in coal fuel expense, declining purchased power expense, lower wheeling expense and increased zero-fuel cost renewable generation, partially offset by declining sales revenue and a small increase in natural gas fuel expense. The Company has updated its GRID modeling in order to send appropriate price signals to customers, improve the accuracy of the net power cost forecast, or recognize costs and benefits not previously modeled. The Company also proposes to include PTCs in the EBA in order to pass back the full and actual value of PTCs. The Company also proposes changes to how the expanded Subscriber Solar Program will be accounted for in the NPC and EBA as discussed in my testimony.

Q. Please summarize your recommendation to the Commission.

A. I recommend that the Commission approve the proposed GRID modeling improvements as outlined in my testimony and adopt the proposed base NPC for the test period of $1.421 billion on a total-Company basis and $619.2 million on a Utah-allocated basis. I also recommend that the Commission allow the inclusion of PTCs in the EBA and approve the Company's recommended changes with regards to the Subscriber Solar Program.

Q. Does this conclude your direct testimony?

A. Yes.

Rocky Mountain Power
Exhibit RMP___(DGW-1)
Docket No. 20-035-04
Witness: David G. Webb

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of David G. Webb

GRID Model NPC Report

May 2020

PacifiCorp

UTGRC20 NPC CONF

Net Power Cost Analysis

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12 months ended December 2021	01/21-12/21	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21
Special Sales For Resale													
Long Term Firm Sales													
Black Hills	7,505,785	737,196	563,577	510,677	345,626	371,342	595,055	746,190	736,430	730,562	717,386	703,085	748,658
BPA Wind	-	-	-	-	-	-	-	-	-	-	-	-	-
East Area Sales (WCA Sale)	-	-	-	-	-	-	-	-	-	-	-	-	-
Hurricane Sale	8,780	732	732	732	732	732	732	732	732	732	732	732	732
LADWP (IPP Layoff)	-	-	-	-	-	-	-	-	-	-	-	-	-
Leaning Juniper Revenue	110,091	6,811	7,295	10,304	5,026	5,690	5,945	16,774	16,065	12,717	8,713	6,709	8,041
SMUD	-	-	-	-	-	-	-	-	-	-	-	-	-
UMPA II s45631	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Long Term Firm Sales	7,624,656	744,739	571,604	521,713	351,384	377,763	601,732	763,696	753,226	744,011	726,831	710,526	757,431
Short Term Firm Sales													
COB	-	-	-	-	-	-	-	-	-	-	-	-	-
Colorado	-	-	-	-	-	-	-	-	-	-	-	-	-
Four Corners	1,127,840	371,000	356,160	400,680	-	-	-	-	-	-	-	-	-
Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-
Mead	-	-	-	-	-	-	-	-	-	-	-	-	-
Mid Columbia	-	-	-	-	-	-	-	-	-	-	-	-	-
Mona	-	-	-	-	-	-	-	-	-	-	-	-	-
NOB	-	-	-	-	-	-	-	-	-	-	-	-	-
Palo Verde	4,870,100	1,646,150	1,524,600	1,699,350	-	-	-	-	-	-	-	-	-
SP15	-	-	-	-	-	-	-	-	-	-	-	-	-
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	-	-	-	-	-	-	-	-	-	-	-	-
West Main	-	-	-	-	-	-	-	-	-	-	-	-	-
Wyoming	-	-	-	-	-	-	-	-	-	-	-	-	-
Electric Swaps Sales	-	-	-	-	-	-	-	-	-	-	-	-	-
STF Trading Margin	-	-	-	-	-	-	-	-	-	-	-	-	-
STF Index Trades	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Short Term Firm Sales	5,997,940	2,017,150	1,880,760	2,100,030	-	-	-	-	-	-	-	-	-
System Balancing Sales													
COB	31,896,519	3,021,063	2,581,609	2,469,727	1,146,541	1,740,985	1,892,518	2,201,146	2,681,767	2,718,220	3,862,223	3,685,574	3,895,146
Four Corners	48,734,581	6,222,291	3,699,657	2,938,074	2,299,634	1,910,011	3,186,366	4,518,242	4,327,486	4,528,125	4,810,730	4,651,519	5,642,447
Mead	29,360,656	3,593,453	3,677,234	1,720,455	975,425	1,054,651	1,511,501	1,958,593	3,158,072	2,577,449	3,097,321	2,860,465	3,176,037
Mid Columbia	29,784,766	1,881,453	1,097,186	572,446	1,592,950	2,267,046	1,112,488	6,062,710	5,191,344	3,186,855	3,148,872	1,963,893	1,707,522
Mona	21,716,134	2,763,679	1,408,512	440,450	744,214	1,017,867	1,619,597	1,746,410	1,812,044	4,143,124	2,105,940	1,568,208	2,346,089
NOB	6,494,307	440,983	446,062	430,433	618,619	121,665	312,102	1,103,090	1,118,677	582,062	75,182	411,762	833,670
Palo Verde	41,866,401	1,716,566	574,912	1,374,942	2,427,253	2,726,022	4,518,774	7,030,025	8,044,454	5,095,260	2,704,237	2,588,356	3,065,601
Trapped Energy	17,896	14,974	2,088	-	224	71	-	-	-	-	-	539	-
Total System Balancing Sales	209,871,260	19,654,461	13,487,258	9,946,527	9,804,860	10,838,319	14,153,345	24,620,217	26,333,844	22,831,094	19,804,505	17,730,317	20,666,512
Total Special Sales For Resale	223,493,856	22,416,350	15,939,622	12,568,270	10,156,244	11,216,082	14,755,078	25,383,912	27,087,071	23,575,106	20,531,335	18,440,843	21,423,943

Purchased Power & Net Interchange

Long Term Firm Purchases													
APS Supplemental	-	-	-	-	-	-	-	-	-	-	-	-	-
Avoided Cost Resource	-	-	-	-	-	-	-	-	-	-	-	-	-
Cedar Springs Wind	11,723,273	1,348,849	1,095,201	1,032,244	1,016,035	830,825	743,881	742,782	585,990	827,498	1,090,534	1,068,343	1,341,093
Cedar Springs Wind III	8,908,095	1,025,294	832,067	784,236	772,110	631,271	565,348	564,366	445,200	628,830	828,668	811,823	1,018,881
Combine Hills Wind	5,369,068	372,723	451,621	547,613	547,338	465,612	400,323	451,804	378,748	357,771	372,201	456,360	566,954
Cove Mountain Solar	3,863,906	185,318	194,698	339,380	369,458	425,244	457,335	443,628	419,763	359,961	289,769	208,202	171,150
Cove Mountain Solar II	343,571	28,534	28,675	28,713	28,701	28,534	28,701	28,624	28,624	28,609	28,624	28,609	28,624
Deseret Purchase	32,990,071	2,935,583	2,832,069	2,635,138	2,359,940	2,344,792	2,741,178	2,948,207	2,948,207	2,917,910	2,897,712	2,519,000	2,910,336
Douglas PUD Settlement	-	-	-	-	-	-	-	-	-	-	-	-	-
Eagle Mountain - UAMPS/UMPA	2,615,653	156,892	141,048	125,873	128,817	154,170	284,603	436,745	407,435	241,073	156,349	153,679	228,968
Gemstate	1,717,824	143,152	143,152	143,152	143,152	143,152	143,152	143,152	143,152	143,152	143,152	143,152	143,152
Georgia-Pacific Camas	-	-	-	-	-	-	-	-	-	-	-	-	-
Hermiston Purchase	-	-	-	-	-	-	-	-	-	-	-	-	-
Hunter Solar	7,122,324	374,917	425,031	647,514	675,791	770,602	797,429	758,093	712,635	664,479	567,050	402,182	326,602
Hurricane Purchase	160,742	13,395	13,395	13,395	13,395	13,395	13,395	13,395	13,395	13,395	13,395	13,395	13,395
IPP Purchase	-	-	-	-	-	-	-	-	-	-	-	-	-
MagCorp	-	-	-	-	-	-	-	-	-	-	-	-	-
MagCorp Reserves	5,084,680	421,050	425,060	421,050	421,050	421,050	421,050	409,020	429,070	429,070	429,070	429,070	429,070
Milican Solar	2,646,179	68,661	138,221	204,961	257,983	306,199	333,290	375,334	331,656	266,914	174,771	111,940	76,250
Milford Solar	7,081,219	358,636	412,994	609,192	677,611	796,634	839,927	747,990	720,080	671,702	541,717	394,020	310,716
Nucor	7,129,800	594,150	594,150	594,150	594,150	594,150	594,150	594,150	594,150	594,150	594,150	594,150	594,150
Old Mill Solar	-	-	-	-	-	-	-	-	-	-	-	-	-
Monsanto Reserves	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
Pavant III Solar	-	-	-	-	-	-	-	-	-	-	-	-	-
PGE Cove	154,785	12,899	12,899	12,899	12,899	12,899	12,899	12,899	12,899	12,899	12,899	12,899	12,899
Prineville Solar	1,795,505	82,013	91,830	136,171	171,397	203,430	221,430	249,362	220,343	177,331	116,113	74,370	51,717
Rock River Wind	3,949,010	647,624	502,957	528,679	435,960	284,843	262,621	181,185	193,222	262,771	490,382	158,766	-
Sigurd Solar	2,905,571	-	-	-	-	-	23,671	660,236	605,234	565,052	458,516	322,228	270,634
Small Purchases east	14,288	1,173	1,213	1,172	1,172	1,233	1,203	1,226	1,202	1,153	1,157	1,209	1,176
Small Purchases west	-	-	-	-	-	-	-	-	-	-	-	-	-
Soda Lake Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-
Three Buttes Wind	20,662,796	2,790,663	1,806,921	2,135,557	1,618,738	1,425,615	1,202,984	807,052	950,561	1,186,424	1,734,559	2,352,376	2,651,346
Top of the World Wind	40,686,138	5,436,527	3,612,759	4,244,151	3,270,658	2,907,364	2,399,806	1,720,417	1,872,120	2,296,841	3,513,203	4,491,632	4,920,662
Tri-State Purchase	-	-	-	-	-	-	-	-	-	-	-	-	-
West Valley Toll	-	-	-	-	-	-	-	-	-	-	-	-	-
Wolverine Creek Wind	10,259,065	760,539	888,633	1,132,686	1,040,512	787,596	844,716	669,522	637,857	752,718	827,852	962,861	953,573
Long Term Firm Purchases Total	197,183,561	19,425,256	16,311,261	17,984,592	16,223,533	15,215,276	14,999,759	14,625,854	14,318,208	15,066,368	16,948,509	17,376,932	18,688,012
Seasonal Purchased Power													
Constellation 2013-2016	-	-	-	-	-	-	-	-	-	-	-	-	-
Seasonal Purchased Power Total	-	-	-	-	-	-	-	-	-	-	-	-	-

Qualifying Facilities													
QF California	2,459,726	215,701	236,633	267,245	312,697	302,769	244,243	166,228	138,407	130,335	133,735	138,107	173,627
QF Idaho	8,526,070	665,205	622,486	675,919	549,840	791,695	853,072	804,323	706,952	676,893	710,906	692,910	775,869
QF Oregon	50,659,824	2,918,983	3,102,799	4,070,906	5,035,956	5,468,588	5,691,241	5,542,450	5,239,793	4,548,585	3,590,005	2,663,496	2,787,021
QF Utah	11,686,984	799,972	834,747	994,336	1,035,869	1,137,833	1,155,642	1,078,323	1,069,390	1,006,203	958,094	845,641	770,935
QF Washington	208,630	-	-	-	3,598	16,682	34,292	47,832	51,603	41,039	13,584	-	-
QF Wyoming	149,045	14,566	13,067	14,455	11,422	10,419	8,672	12,538	12,397	9,613	12,059	12,545	17,290
Biomass One QF	14,325,868	1,137,736	1,170,257	1,267,946	1,426,566	928,933	496,148	1,441,224	1,430,184	1,394,481	1,437,697	1,443,413	751,283
Boswell Wind I QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Boswell Wind II QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Boswell Wind III QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Boswell Wind IV QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Chevron Wind QF	-	-	-	-	-	-	-	-	-	-	-	-	-
DCFP QF	119,066	3,390	6,084	5,901	4,769	4,661	7,241	17,585	19,050	24,343	12,375	6,980	6,686
Enterprise Solar I QF	12,563,411	617,060	756,870	980,643	1,117,038	1,257,240	1,382,198	1,554,604	1,501,679	1,181,692	957,986	710,651	545,749
Escalante Solar I QF	11,601,502	565,498	685,084	883,730	1,015,842	1,191,044	1,306,249	1,436,464	1,391,659	1,094,914	874,125	648,324	508,570
Escalante Solar II QF	10,921,713	531,489	645,513	832,362	955,502	1,126,572	1,235,898	1,359,761	1,304,268	1,031,738	818,007	606,453	474,150
Escalante Solar III QF	10,520,640	517,551	627,997	806,129	929,679	1,098,975	1,206,563	1,321,201	1,268,974	1,003,181	750,305	555,442	434,642
Evergreen BioPower QF	-	-	-	-	-	-	-	-	-	-	-	-	-
ExxonMobil QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Five Pine Wind QF	8,399,980	515,184	843,295	749,871	802,885	485,845	529,260	630,392	591,216	751,568	738,975	881,157	880,334
Foote Creek III Wind QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Glen Canyon A Solar QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Glen Canyon B Solar QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Granite Mountain East Solar QF	10,913,761	548,826	618,770	895,198	990,554	1,158,651	1,258,453	1,338,832	1,261,328	978,568	810,799	585,874	467,909
Granite Mountain West Solar QF	7,220,477	363,517	409,549	593,815	657,017	766,608	830,760	887,222	834,460	645,109	536,218	387,167	309,035
Iron Springs Solar QF	11,200,371	634,276	666,108	897,183	1,017,893	1,130,820	1,283,100	1,346,598	1,318,721	1,006,219	817,161	582,281	500,011
Kennecott Refinery QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Kennecott Smelter QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Latigo Wind Park QF	9,674,740	1,007,477	917,570	1,126,955	897,120	856,897	745,979	673,722	567,152	616,686	799,252	709,690	756,240
Monticello Wind QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Mountain Wind 1 QF	8,916,080	1,397,705	1,044,898	869,816	693,034	479,607	498,327	410,860	440,933	454,827	672,574	927,984	1,025,515
Mountain Wind 2 QF	13,895,033	2,038,485	1,566,199	1,352,529	1,078,715	750,861	890,296	761,455	734,168	757,712	1,009,557	1,435,299	1,519,756
North Point Wind QF	18,786,576	1,081,867	1,817,411	1,672,826	1,801,611	1,084,057	1,202,040	1,464,551	1,465,394	1,786,186	1,717,960	1,871,542	1,821,132
Oregon Wind Farm QF	12,468,790	729,863	971,742	1,115,635	1,312,368	1,260,505	1,201,740	1,261,216	1,114,406	919,426	735,727	801,716	1,044,447
Pavant II Solar QF	4,310,019	177,389	225,179	346,901	399,215	454,358	476,933	558,197	543,942	425,101	330,218	205,953	166,635
Pioneer Wind Park I QF	10,668,383	1,307,976	927,722	1,190,414	907,777	706,052	651,560	651,076	681,633	452,761	823,624	1,265,841	1,101,946
Power County North Wind QF	5,460,338	415,705	548,470	525,351	519,896	350,950	344,576	370,353	360,112	380,493	511,430	530,622	602,381
Power County South Wind QF	4,865,045	367,049	482,868	474,030	482,998	302,560	306,289	327,761	335,462	336,896	447,464	479,428	522,241
Roseburg Dillard QF	1,042,678	52,652	45,323	49,453	117,831	106,620	104,258	164,486	131,433	66,116	76,189	75,916	52,402
Sage I Solar QF	2,270,456	80,679	79,891	190,158	206,003	234,995	262,709	337,883	333,611	208,547	155,711	104,870	75,399
Sage II Solar QF	2,272,891	80,764	79,986	190,360	206,223	235,208	263,006	338,244	333,976	208,784	155,870	105,000	75,469
Sage III Solar QF	1,870,483	68,007	66,563	157,054	167,907	192,623	214,874	275,730	272,050	172,117	130,624	88,886	64,050
Spanish Fork Wind 2 QF	2,754,893	217,428	177,317	204,533	160,626	154,092	210,749	289,636	315,766	271,043	242,505	250,579	260,620
Sunnyside QF	30,904,807	2,757,966	2,577,196	2,680,631	1,719,211	2,720,081	2,750,586	2,752,683	2,714,248	2,577,478	2,367,927	2,749,169	2,537,628
Sweetwater Solar QF	7,797,376	259,240	374,746	567,022	689,492	814,366	985,566	1,121,979	1,038,739	815,928	628,052	300,112	202,134
Tesoro QF	299,767	50,859	22,516	27,152	24,386	45,902	8,670	11,194	17,560	15,953	18,144	18,180	39,251
Threemile Canyon Wind QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Three Peaks Solar QF	8,452,878	411,976	477,957	625,721	834,509	860,254	911,132	1,042,848	998,463	794,907	672,624	450,022	372,466
Utah Pavant Solar QF	5,611,720	208,301	240,534	410,490	470,172	563,656	662,527	772,097	721,480	602,883	450,433	279,646	229,501
Utah Red Hills Solar QF	11,565,119	484,032	621,327	787,698	1,034,405	1,204,547	1,240,486	1,530,453	1,463,983	1,326,491	812,004	594,449	465,244
Qualifying Facilities Total	335,365,139	23,244,375	24,504,675	28,500,365	29,590,624	30,255,524	31,455,334	34,102,001	32,724,591	28,714,814	25,929,922	24,005,344	22,337,570
Mid-Columbia Contracts													
Douglas - Wells	-	-	-	-	-	-	-	-	-	-	-	-	-
Grant Reasonable	(373,959)	(31,163)	(31,163)	(31,163)	(31,163)	(31,163)	(31,163)	(31,163)	(31,163)	(31,163)	(31,163)	(31,163)	(31,163)
Grant Meaningful Priority	-	-	-	-	-	-	-	-	-	-	-	-	-
Grant Surplus	2,136,095	178,008	178,008	178,008	178,008	178,008	178,008	178,008	178,008	178,008	178,008	178,008	178,008
Grant - Priest Rapids	-	-	-	-	-	-	-	-	-	-	-	-	-
Mid-Columbia Contracts Total	1,762,136	146,845	146,845	146,845	146,845	146,845	146,845	146,845	146,845	146,845	146,845	146,845	146,845
Total Long Term Firm Purchases	534,310,836	42,816,475	40,962,780	46,631,801	45,961,002	45,617,645	46,601,937	48,874,701	47,189,644	43,928,027	43,025,276	41,529,121	41,172,427

Storage & Exchange													
APS Exchange	-	-	-	-	-	-	-	-	-	-	-	-	-
Black Hills CTs	-	-	-	-	-	-	-	-	-	-	-	-	-
BPA Exchange	-	-	-	-	-	-	-	-	-	-	-	-	-
BPA FC II Wind	-	-	-	-	-	-	-	-	-	-	-	-	-
BPA FC IV Wind	-	-	-	-	-	-	-	-	-	-	-	-	-
BPA So. Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-
Cowlitz Swift	-	-	-	-	-	-	-	-	-	-	-	-	-
EWEB FC I	-	-	-	-	-	-	-	-	-	-	-	-	-
PSCo Exchange	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	-	-	-	-	-	-	-	-	-	-	-	-	-
Redding Exchange	-	-	-	-	-	-	-	-	-	-	-	-	-
SCL State Line	-	-	-	-	-	-	-	-	-	-	-	-	-
Tri-State Exchange	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Storage & Exchange	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
Short Term Firm Purchases													
COB	-	-	-	-	-	-	-	-	-	-	-	-	-
Colorado	-	-	-	-	-	-	-	-	-	-	-	-	-
Four Corners	-	-	-	-	-	-	-	-	-	-	-	-	-
Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-
Mead	-	-	-	-	-	-	-	-	-	-	-	-	-
Mid Columbia	1,094,400	360,000	345,600	388,800	-	-	-	-	-	-	-	-	-
Mona	-	-	-	-	-	-	-	-	-	-	-	-	-
NOB	-	-	-	-	-	-	-	-	-	-	-	-	-
Palo Verde	-	-	-	-	-	-	-	-	-	-	-	-	-
SP15	-	-	-	-	-	-	-	-	-	-	-	-	-
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	-	-	-	-	-	-	-	-	-	-	-	-
West Main	-	-	-	-	-	-	-	-	-	-	-	-	-
Wyoming	-	-	-	-	-	-	-	-	-	-	-	-	-
STF Electric Swaps	-	-	-	-	-	-	-	-	-	-	-	-	-
STF Index Trades	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Short Term Firm Purchases	1,094,400	360,000	345,600	388,800	-	-	-	-	-	-	-	-	-
System Balancing Purchases													
COB	9,370,692	281,937	812,238	1,218,258	412,429	322,429	1,417,907	1,393,481	1,212,611	676,532	115,104	110,560	1,397,205
Four Corners	16,556,519	1,202,684	2,746,223	3,442,577	1,860,401	819,265	78,711	145,878	492,285	1,317,095	1,149,585	1,371,943	1,929,871
Mead	5,146,900	219,827	463,653	364,042	265,253	288,640	343,194	971,913	264,723	372,356	460,043	679,820	453,434
Mid Columbia	67,813,660	4,137,289	3,241,123	1,381,742	2,048,171	10,701,044	7,148,960	15,919,877	13,290,736	3,016,960	1,283,093	1,710,286	3,934,379
Mona	10,089,241	1,285,165	834,591	189,563	465,073	761,997	27,072	1,068,725	941,037	944,305	1,146,372	1,139,013	1,286,328
NOB	12,905,923	864,262	916,039	636,894	946,532	215,697	465,437	2,228,854	2,488,417	1,142,711	242,197	949,907	1,808,976
Palo Verde	1,150,203	95,850	95,850	95,850	95,850	95,850	95,850	95,850	95,850	95,850	95,850	95,850	95,850
EIM Imports/Exports	(64,594,041)	(3,477,483)	(3,102,409)	(8,578,822)	(8,746,296)	(8,972,657)	(3,177,393)	(6,964,351)	(7,193,600)	(4,914,121)	(2,979,604)	(2,911,632)	(3,575,674)
Emergency Purchases	520,874	424	750	251,658	136,693	45,864	3,987	56,102	481	67	24,137	711	-
Total System Balancing Purchases	58,959,970	4,609,955	6,008,058	(998,237)	(2,515,893)	4,278,130	6,403,726	14,916,330	11,592,540	2,651,756	1,536,777	3,146,458	7,330,370
Total Purchased Power & Net Interch	599,765,206	48,236,430	47,766,438	46,472,364	43,895,109	50,345,775	53,455,663	64,241,031	59,232,184	47,029,782	45,012,053	45,125,579	48,952,797

Wheeling & U. of F. Expense													
Firm Wheeling	144,697,684	11,749,372	11,482,343	11,451,463	10,034,554	9,720,807	16,198,114	11,657,890	11,684,246	12,376,159	12,210,595	12,829,755	13,302,386
C&T EIM Admin fee	2,022,748	153,010	131,133	172,440	211,710	248,077	216,704	172,436	135,045	153,613	170,764	127,508	130,308
ST Firm & Non-Firm	30,409	8,052	2,410	814	-	-	621	5,204	4,982	3,621	1,130	1,817	1,758
Total Wheeling & U. of F. Expense	146,750,840	11,910,435	11,615,886	11,624,717	10,246,264	9,968,884	16,415,440	11,835,530	11,824,272	12,533,393	12,382,488	12,959,080	13,434,452
Coal Fuel Burn Expense													
Carbon	-	-	-	-	-	-	-	-	-	-	-	-	-
Cholla	-	-	-	-	-	-	-	-	-	-	-	-	-
Colstrip	15,158,709	1,782,525	1,423,601	1,314,080	944,674	834,921	1,030,653	1,577,622	1,569,312	1,173,369	513,179	1,482,926	1,511,845
Craig	16,846,426	1,493,073	1,338,082	1,413,099	1,290,554	1,414,710	1,185,226	1,521,698	1,637,334	1,327,530	1,421,153	1,314,051	1,489,917
Dave Johnston	49,180,718	4,419,689	4,150,292	3,514,048	3,011,683	3,256,116	3,635,457	4,771,396	5,228,144	4,469,846	4,451,189	3,797,831	4,475,028
Hayden	14,706,480	1,397,927	1,198,893	995,646	1,014,078	1,014,757	1,326,435	1,321,986	1,225,980	1,329,757	1,212,614	1,322,376	1,346,030
Hunter	93,416,653	11,773,216	9,320,619	6,875,944	3,603,450	4,656,525	5,785,675	8,873,457	8,010,836	6,488,452	5,887,757	10,235,627	11,905,094
Huntington	99,290,293	11,718,366	9,558,333	8,335,116	5,237,773	4,686,886	5,432,963	10,036,063	9,831,910	7,547,103	5,922,493	8,485,949	12,497,339
Jim Bridger	204,389,262	14,463,003	15,521,775	17,760,298	13,333,175	10,201,448	14,930,254	24,356,600	23,885,889	18,720,617	18,017,349	17,355,929	15,842,925
Naughton	76,667,756	7,570,416	6,753,872	6,757,778	4,832,490	4,295,489	5,790,326	6,963,124	7,115,510	7,017,292	6,229,928	6,676,243	6,665,288
Wyodak	25,402,913	2,322,485	2,337,815	1,858,095	1,342,933	2,078,389	1,937,743	2,723,619	2,563,936	2,385,795	2,290,579	2,024,747	1,536,777
Total Coal Fuel Burn Expense	595,059,209	56,940,699	51,603,282	48,824,105	34,610,810	32,439,242	41,054,731	62,145,565	61,068,851	50,459,760	45,946,240	52,695,681	57,270,241
Gas Fuel Burn Expense													
Chehalis	46,621,569	5,219,432	1,830,013	3,242,985	2,352,099	3,551,746	2,883,763	4,658,620	4,756,101	4,557,472	5,319,835	2,897,655	5,351,847
Currant Creek	39,627,560	1,338,560	816,687	1,775,737	2,647,785	2,846,807	4,212,465	4,638,863	4,128,454	4,409,599	4,313,083	4,356,877	4,142,644
Gadsby	3,759,815	-	102,758	204,046	77,285	83,671	255,780	714,416	692,813	398,423	250,763	351,861	627,999
Gadsby CT	1,687,868	9,641	31,960	45,735	15,115	17,708	64,715	350,346	298,062	135,942	124,212	141,289	453,143
Hermiston	22,505,463	2,150,155	1,577,574	1,288,039	1,870,607	935,346	1,168,672	2,046,301	2,241,483	2,186,304	2,385,181	2,522,510	2,133,292
Lake Side 1	55,115,582	3,942,462	3,210,025	3,349,127	4,201,835	4,596,818	4,852,768	5,739,349	5,896,743	5,425,256	4,741,446	4,759,463	4,400,291
Lake Side 2	53,612,639	5,428,783	4,288,011	4,129,668	4,335,492	3,795,552	4,816,403	4,761,636	4,794,697	3,851,197	3,932,900	3,992,474	5,485,829
Little Mountain	-	-	-	-	-	-	-	-	-	-	-	-	-
Naughton - Gas	22,760,746	2,810,516	2,007,627	1,357,433	2,319,655	2,458,709	2,009,636	1,680,249	1,490,184	1,016,005	1,839,083	1,394,923	2,376,726
Not Used	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Gas Fuel Burn	245,691,243	20,899,547	13,864,655	15,392,769	17,819,874	18,286,357	20,264,201	24,589,780	24,298,536	21,980,197	22,906,503	20,417,053	24,971,771
Gas Physical	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas Swaps	16,779,163	107,958	574,350	2,058,478	1,780,200	1,935,640	1,733,700	1,348,578	1,323,855	1,392,075	2,341,585	1,468,350	714,395
Clay Basin Gas Storage	(29,961)	(132,136)	(104,285)	(29,237)	52,242	52,242	52,242	52,242	52,242	52,242	52,242	(25,669)	(104,331)
Pipeline Reservation Fees	36,317,735	3,030,219	2,915,834	3,039,200	2,993,761	3,034,107	3,009,667	3,074,081	3,071,440	3,015,726	3,050,970	3,014,404	3,068,327
Total Gas Fuel Burn Expense	298,758,180	23,905,588	17,250,554	20,461,209	22,646,077	23,308,347	25,059,810	29,064,681	28,746,074	26,440,240	28,351,300	24,874,138	28,650,162
Other Generation													
Blundell	4,497,520	448,014	356,628	418,112	407,272	415,782	384,237	373,294	385,568	401,632	407,038	225,018	274,926
Blundell Bottoming Cycle	-	-	-	-	-	-	-	-	-	-	-	-	-
Cedar Springs Wind II	-												
Dunlap I Wind	-												
Ekola Flats Wind	-												
Foote Creek I Wind	-												
Glenrock Wind	-												
Glenrock III Wind	-												
Goodnoe Wind	-												
High Plains Wind	-												
Leaning Juniper 1	-												
Marengo I Wind	-												
Marengo II Wind	-												
McFadden Ridge Wind	-												
Pryor Mountain Wind	-												
Rolling Hills Wind	-												

Seven Mile Wind	-												
Seven Mile II Wind	-												
Black Cap Solar													
TB Flats Wind													
TB Flats Wind II													
Integration Charge	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Other Generation	4,497,520	448,014	356,628	418,112	407,272	415,782	384,237	373,294	385,568	401,632	407,038	225,018	274,926
Net Power Cost	1,421,337,099	119,024,815	112,653,167	115,232,238	101,649,287	105,261,948	121,614,803	142,276,189	134,169,878	113,289,702	111,567,784	117,438,652	127,158,635