BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION	)	CASE NO. PAC-E-24-04
OF ROCKY MOUNTAIN POWER FOR	)	
AUTHORITY TO INCREASE ITS RATES	)	DIRECT TESTIMONY OF
AND CHARGES IN IDAHO AND	)	RAMON J. MITCHELL
APPROVAL OF PROPOSED	)	REDACTED
ELECTRIC SERVICE SCHEDULES AND	)	
REGULATIONS	)	

ROCKY MOUNTAIN POWER

CASE NO. PAC-E-24-04

May 2024

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 Ramon J. Mitchell, 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 Business Administration degree from the University of Portland and a Bachelor of Arts degree in Economics from Reed College. I was first employed by the Company in 2015 and during my time at the Company I have held various positions in the regulation, merchant, and transmission departments. After a brief departure from the Company, in 2022 I returned to the Company as Manager, Net Power Costs. In my current role I am responsible for leading and overseeing various efforts associated with the Company's net power costs filings.

Q. Have you testified in previous regulatory proceedings?

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

II. PURPOSE OF TESTIMONY

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

A. My testimony presents the Company's proposed net power costs ("NPC") for the 12-month forecast period ending December 31, 2025 ("NPC test period"); and proposes changes to the annual Energy Cost Adjustment Mechanism ("ECAM") to update the sharing band. The proposed NPC would become the new base NPC for the ECAM, beginning January 1, 2025. Specifically, my testimony:

- Supports removing Renewable Energy Credit ("REC") adjustments from the ECAM;
- Discusses Federal Energy Regulatory Commission ("FERC") Order No. 898 which moves certain costs from FERC account 555 to FERC account 509;
- Provides detail on the NPC component of the Company's rate mitigation proposal, which will ease financial burdens on the Company's customers;
- Summarizes forecasted NPC for the 2025 NPC test period in this general rate case ("GRC") and explains the calculation of NPC using the Company's Aurora production cost model;
- Explains the primary drivers behind the increase in NPC compared to the current base NPC approved by the Commission and incorporated into customer rates in the Company's last general rate case, Case No. PAC-E-21-07[1] ("2021 GRC"), which includes a discussion of extraordinary increases in regional wholesale electricity (power) and natural gas fuel (gas) market prices since the 2021 GRC;

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[1] *In the Matter of the Application of Rocky Mountain Power for Authority to Increase its Rates and Charges in Idaho and Approval of Proposed Electric Service Schedules and Regulations,* Case No. PAC-E-21-07, Order No. 35277 (Dec. 30, 2021).

- Describes new policy changes and operations changes since the 2021 GRC that substantially impact NPC;
- Describes modeling changes the Company has made to improve the NPC forecast accuracy since the 2021 GRC; and
- Proposes updating the ECAM sharing band considering the Company's pending participation in a complete organized market along with observations on trends in western markets since the inception of the current sharing band in 2009.

Q. Is there a summary of the proposed ECAM Base amounts to be set in this filing for future ECAM filings?

A. Yes. Exhibit No. 51 attached to the testimony of Company witness Shelley M. McCoy, summarizes the proposed base amounts for all elements for ECAM deferrals beginning January 1, 2025. In addition to NPC discussed in my testimony, the ECAM deferral includes the difference between actual and base amounts for production tax credits, and load change adjustment revenues.

Q. How is the testimony organized?

A. In section II, I first present the Company's proposal to adjust the ECAM to remove REC adjustments and I discuss FERC Order No. 898. I then provide an overview of the NPC forecast for the 2025 NPC test period. This overview includes a high-level discussion of the NPC changes since the 2021 GRC followed by a more detailed discussion of the individual NPC components along with narrative explanations which touch on the impacts associated with new policy and operations changes.

Next, Section III includes a discussion on the reasonableness of the NPC forecast and section IV explores in detail the drivers of regional forward power market prices and regional forward fuel prices which account for the majority of the change in the NPC forecast since the 2021 GRC.

Section V discusses in detail new policy and operations changes, along with the numeric impacts to the NPC forecast that each change represents.

In Section VI, I discuss the transition from the Generation and Regulation Initiative Decision Tools production cost model ("GRID") to the Aurora production cost model ("Aurora") for the forecast of NPC, then in Section VII, I present and discuss changes to improve modeling accuracy along with the numeric impacts to the NPC forecast that each improvement represents.

In section VIII I transition the discussion to the proposed NPC forecast based on 2023 weather normalized load.

Finally, after the NPC portion of my testimony, I transition into a discussion on NPC recovery in the ECAM, in section IX.

Q. Please describe the proposed change in the ECAM related to RECs.

A. The Company is proposing to remove the REC revenue adjustment from the annual ECAM calculation. As described in Company witness Craig M. Eller's testimony, the Company is proposing a new voluntary REC option tariff. Company witness McCoy addresses the Company's proposed adjustments to the revenue requirement in this case to facilitate the REC option tariff and Company witness Robert M. Meredith introduces the proposed tariff Electric Service Schedule No. 98 – REC Revenue Adjustment ("RRA"). Since REC revenue would now be passed back to customers through proposed tariff Electric Service Schedule No. 98, the REC revenue adjustment would no longer be included in the ECAM.

Q. Please describe the movement of costs from FERC account 555 to FERC account 509.

A. On June 29, 2023, the FERC issued Order No. 898 (Docket No. RM21-11-000),[2] Accounting and Reporting Treatment of Certain Renewable Energy Assets, to change the accounting required for certain types of costs that have been previously booked to FERC Account 555 to be booked

[2] *File Rule*, 183 FERC ¶ 61,205, Docket No. RM21-11-000 (Jun. 29, 2023) *available at* https://www.ferc.gov/media/order-no-898.

to FERC account 509. This change becomes effective on January 1, 2025.

Q. What costs will be affected by FERC's Order No. 898 beginning January 1, 2025?

A. The change in accounting affects the costs associated with greenhouse gas ("GHG") allowances that have been historically booked to FERC account 555. Specifically for NPC, California GHG costs and Washington GHG costs will be booked to FERC account 509, beginning January 1, 2025. Correspondingly, for those costs which would have been recovered from FERC account 555, the Company advises that they will now be recovered from FERC account 509.

Q. Please provide detail on the NPC component of the Company's proposed rate mitigation proposal.

A. The Company proposes to phase in the increase to the base ECAM across two years, with the ability to recover 100 percent of any ECAM variance up to and no further than the Company's proposed ECAM forecast. The proposed ECAM forecast on a dollar per megawatt hour ($/MWh) basis is $39.34/MWh and the ECAM base currently in rates is $24.54/MWh. The rate mitigation proposal in this context would phase in the proposed ECAM through two steps by increasing the base from $24.54/MWh to $31.94/MWh on January 1, 2025, and then increasing the base from

$31.94/MWh to $39.34/MWh on January 1, 2026. As part of this phase-in across the two years, the Company proposes that the ECAM sharing band would only apply to ECAM variances above $39.34/MWh or below $24.54/MWh, with 100 percent recovery of ECAM variances between the $24.54/MWh base and the $39.34/MWh forecast. Company witness Joelle R. Steward discusses this proposal in further detail.

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

A. NPC are defined as the sum of fuel expenses, wholesale purchased power expenses, allowances, 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 the Company's annual ECAM filings.

Q. Please explain how the Company calculates NPC.

A. NPC are calculated for the forecast NPC test period based on projected data using Aurora, which simulates the operation of the Company's power system on an hourly basis. The production cost model respects all system requirements and constraints and commits and dispatches the Company's resources for an NPC-minimizing output where demand and supply are balanced.

Q. Which version of Aurora was used to prepare this initial filing?

A. The Aurora version used to prepare this initial filing was version 14.2.1059.[3] No other version of Aurora is assured to be able to identically reproduce the NPC proposal in this initial filing. This - and all - Aurora versions are available upon request from Energy Exemplar provided that a license agreement is in place that allows utilization of the software.

Q. What Aurora inputs were updated for this filing?

A. All inputs have been updated since the 2021 GRC, including system load, reserves, 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. Did the Company update regulation reserves for this filing?

A. Yes, consistent with the prior GRC, the Company has updated regulation reserves to be aligned with the

[3] Specifically, Aurora version 14.2.1059 released on May 23, 2023.

recent integrated resource plan's ("IRP") flexible reserve study.[4]

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

A. The forecast for 2025 NPC uses the OFPC dated March 29, 2024.

Q. What reports do the Aurora model produce?

A. The major output from the Aurora model is the NPC report, which is attached to my testimony as Exhibit No. 23.

Q. What is the proposed total-Company NPC for the 2025 NPC test period?

A. Under 2023 weather normalized load conditions, the proposed NPC for the 2025 NPC test period is $2.382 billion, or $39.19/MWh, on a total-Company basis; or $136.7 million, or $39.34/MWh on an Idaho-allocated basis.

However, for narrative accuracy, the following testimony provides NPC analyses **based upon an NPC forecast using expected NPC test period load (i.e., 2025 forecast load), unless otherwise noted.** Then, at the end of my testimony a final adjustment is made to bring NPC in line with 2023 weather normalized load.

[4] *See* PacifiCorp 2021 Integrated Resource Plan, Appendix F and PacifiCorp 2023 Integrated Resource Plan, Appendix F.

Under 2025 load forecast conditions, NPC for the 2025 NPC test period are $2.651 billion, or $39.83/MWh, on a total-Company basis. 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 changes in 2025 NPC as compared to the 2021 NPC forecasted in the 2021 GRC.

A. Using the 2023 weather normalized NPC forecast to compare to the 2021 GRC, which was also weather normalized, the changes to NPC on a total-Company basis are illustrated below in Table 'NPC Variance Between GRCs' and the associated energy changes on a total-Company basis are illustrated below in Table 'Energy Variance Between GRCs'. Below, I expand on the individual line items.

Table NPC Variance Between GRCs

Net Power Cost Reconciliation ($)		
	($ millions)	$/MWh
ID 2021 GRC Final Forecast	1,368	23.41
Increase/(Decrease) to NPC:		
Wholesale Sales Revenue	(201.7)	
Purchased Power Expense	386.4	
Coal Fuel Expense	77.4	
Natural Gas Fuel Expense	308.2	
Wheeling and Other Expense	39.6	
Total Increase/(Decrease) to NPC	**1013.4**	
ID 2024 GRC Initial Forecast	**2,382**	39.19

Table Energy Variance Between GRCs

Net Power Cost Reconciliation (MWh)		
	MWh	$/MWh
ID 2021 GRC Final Forecast	58,444,451	23.41
Change to Net System Load:		
Wholesale Sales Decrease	(7,334,748)	
Purchased Power Increase	1,862,120	
Coal Generation Decrease	(8,838,653)	
Natural Gas Generation Increase	3,580,407	
Other Generation Decrease	(1,594,690)	
Total Change to Net System Load	**2,343,932**	
ID 2025 GRC Initial	**60,788,384**	39.19

Q. Please explain the increase in purchased power expense.

A. The purchased power expense increases in tandem with power market prices supplemented by increased purchased power volumes due to: (1) reduced coal supply availability in Utah; (2) the decrease in generation at the Chehalis plant due to the Washington Cap and Invest Program ("WA-GHG"); and (3) lower hydroelectric generation driven by the deconstruction/removal of Klamath River hydroelectric facilities. I explain these individual drivers in more detail below.

Q. Please explain the increase in coal fuel expense and the increase in natural gas fuel expense.

A. The coal fuel expense increases due to coal fuel price increases which result from increased domestic competition for limited coal supply. Some of the coal fuel expense is offset by: (1) coal supply challenges, which decrease the amount of generation at certain coal facilities; and (2) the gas conversion of Jim Bridger units 1 and 2, which removes two generating units from the coal fuel expense category. Natural gas fuel expense increases due to: (1) the gas conversion of Jim Bridger units 1 and 2, which adds two generating units into the natural gas fuel expense category; and (2) increased dispatch of natural gas units to meet load and reserve obligations. Natural gas fuel expense also increases in tandem with natural gas market prices.

Q. Please explain the decrease in wholesale sales revenue and the increase in wheeling and other expense.

A. With decreased net generation, wholesale sales volumes also decrease. Wheeling expenses increase relative to the forecast in the 2021 GRC based on increases in the historical wheeling expenses supporting recent actual purchased power volumes.

Q. Please summarize the overall changes.

A. The overall changes are driven by: 1) the NPC under-forecast in the 2021 GRC; and 2) increases in purchased power and natural gas fuel expense that result from increased power and natural gas commodity prices, a reduction in generation due to the WA-GHG program, the expectation of lower hydroelectric generation resulting from the deconstruction of hydroelectric facilities along the Klamath River, and coal supply challenges.

III. NPC VALIDATION

Q As an initial matter, please discuss the 2021 NPC forecast from the prior GRC.

A The prior GRC forecasted NPC of $1.368 billion total-Company for calendar year 2021. Actual total-Company NPC for calendar year 2021 were $1.715 billion. Therefore, the prior GRC's NPC was a $347 million total-Company under-forecast for the 2021 NPC test period.

Q. Is $2.651 billion a reasonable forecast for total-Company 2025 NPC using 2025 load expectations?

A. Yes. Calendar year 2023 actual NPC are $2.555 billion. In 2025, as compared to 2023:

(1) At the total-Company level, 2025 forecast NPC are $2.651 billion, or $39.83/MWh while 2023 actual NPC are $2.555 billion, or $41.26/MWh. On a dollar basis, NPC increase by 3.7 percent, **however** on a $/MWh basis, NPC **decrease** by 3.5 percent;

(2) 2025 Pacific Northwest summer and winter peak power prices **increase** by 18 percent and Desert Southwest summer and winter peak power prices **increase** by 9 percent;

(3) 2025 Pacific Northwest summer and winter natural gas prices **increase** by 54 percent and Rocky Mountain region summer and winter natural gas prices **increase** by 21 percent (both calculations excluding the anomalous January 2023 price excursion);[5] and

(4) Although new Company-owned $0/MWh marginal cost wind is estimated to produce 1.1 million megawatt-hours ("MWh") more at the total-Company level, as compared to 2023; load increases by 4.7 million MWh at the total-Company level, as compared to 2023, and completely absorbs that increased wind production. After subtracting the new Company owned wind generation increase, the remaining load increase is 3.6 million MWh.

These fundamentals indicate that 2025 total-Company NPC will be higher than 2023 total-Company NPC. All else equal, the remaining load increase valued at the average

[5] The Company excluded the outlier data from January 2023 because inclusion of that anomalous price spike skews the comparison of 2023 to 2025 data. However, in the interest of complete analysis for the record, from 2023 to 2025, *January* natural gas prices in the Pacific Northwest and in the Rocky Mountain region decreased by 31 percent and 56 percent, respectively.

NPC of $39.83/MWh suggests that 2025 NPC should be an increase of $142 million relative to 2023 NPC. This implied increase is a conservative estimate given that load increases are more likely to be fulfilled by market purchases rather than the pre-existing generation mix. From this basic analysis, the 2025 NPC forecast, pre-weather normalization, is within reason, if not conservative.

Q. Why are summer and winter prices particularly critical when comparing price changes?

A. Summer and winter peak periods are periods of high customer demand and stressed system conditions and higher power prices in those periods will produce NPC that is substantially higher relative to any decrease in NPC that may result from lowered prices in spring and fall months, which have light load and relatively mild system conditions.

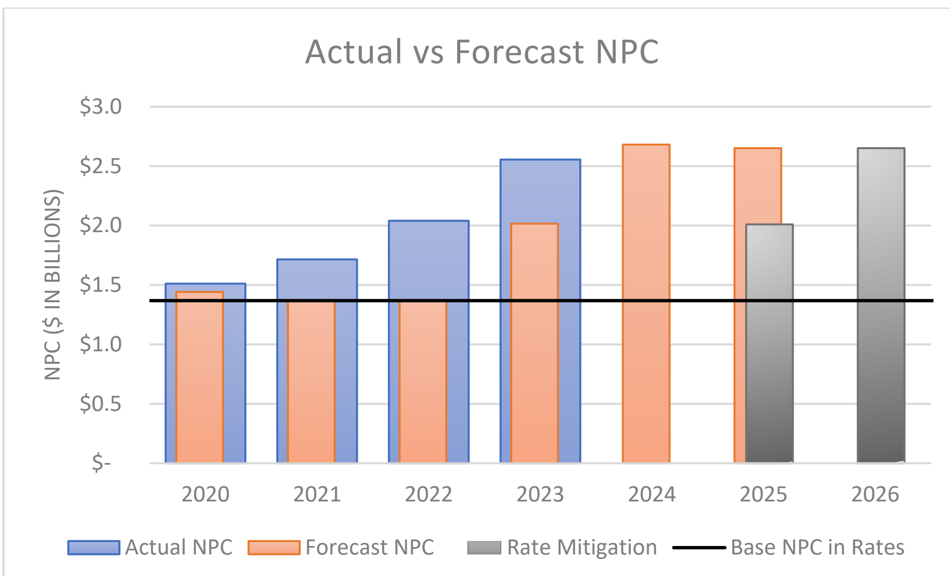
Q. Please provide the actual NPC incurred by the Company since the filing of the prior GRC.

A. Table 'NPC Variance' and Figure 'NPC Variance' show both actual and forecast NPC from calendar year ("CY") 2020 to CY 2025 where available.

Table NPC Variance[6]

NPC Year	Total Company *Actual* NPC ($)	Total Company *Forecast* NPC ($)	Rate Mitigation *Proposed* NPC ($)
2020	1,511,314,189	1,441,320,020	
2021	1,714,607,879	1,367,917,419	
2022	2,040,318,303	1,369,404,716	
2023	2,555,124,438	2,016,140,036	
2024		2,681,145,109	
2025		2,650,729,651	2,009,323,535
2026			2,650,729,651

Figure NPC Variance[7]



As can be seen in Table 'NPC Variance' and Figure 'NPC Variance', not only was there a substantial NPC under-forecast in the prior GRC which forecasted CY 2021; also, actual NPC from 2020 to 2023 has increased year over year. Most of this increase is attributable to

[6] Calendar years 2020, 2022, 2023 and 2024 pull forecasts from the Oregon Transition Adjustment Mechanism.
[7] *Id.*

wholesale electricity (power) and natural gas fuel market prices, weather conditions, fuel supply constraints, retail load increases, and regulatory obligations.

Also of note is that calendar years 2020, 2021, 2022, and 2023 have seen an increase in abnormal/extreme weather events that have resulted in higher-than-expected load during stressed system conditions, and this trend has set expectations amongst market participants for similar conditions in 2024 and 2025.

Q. Please describe some of the changes in system conditions experienced by the Company in 2021, the prior GRC's NPC test period.

A. In CY 2021, a few extreme and unforeseen weather events drove increases in actual NPC. For instance, there was a polar vortex engulfing the region in February 2021 and a heat dome event in July 2021. The average purchased power price was $30.68/MWh higher than the average purchased power price forecasted in the base NPC, contributing to a substantial increase in purchased power expense. Additionally, the Company also faced severe drought conditions that resulted in hydroelectric generation being lower than forecast, resulting in increased purchased power volumes - and associated expense - to provide replacement energy. The Company also faced supply chain issues that were a result of a global supply chain disruption which resulted in construction delays for many of the Company's renewable resources that would have otherwise achieved an earlier commercial online date. These delays resulted in increased purchased power volumes and associated expense.

Q. Please describe some of the changes in system conditions experienced by the Company in 2022.

A. In CY 2022, like 2021, unforeseen weather events again drove increases in actual NPC, such as the multiple heat waves in the region during the summer of 2022 and ongoing drought conditions. These drivers increased peak period power prices and reduced hydro generation availability, respectively. Similarly, there was a historic cyclone event in the winter of 2022 that impacted power and natural gas prices. For example, average prices at the Opal natural gas trading hub were 424 percent higher in December 2022 as compared to December 2021 while peak power prices at the Mid-Columbia trading hub were 380 percent higher. Lastly, the Russian invasion of Ukraine substantially increased natural gas market prices throughout the year. These events, taken together, contributed to substantial increases in purchased power expense and natural gas fuel expense.

Q. Please describe some of the changes in system conditions experienced by the Company in 2023.

A. In CY 2023 coal fuel supply constraints, which began at the end of CY 2022: (1) continued throughout 2023; (2) still impact the Company today; and (3) are anticipated to continue through 2025. On a more comprehensive note, power prices and natural gas prices have risen sharply since the beginning of 2021. Between 2016 and 2020, the average monthly heavy load hour ("HLH") market price at the Mid-Columbia power trading hub ("Mid-C") was \$29.27/MWh and at the Four Corners trading hub ("4C"), \$35.11/MWh. This is compared to the average monthly HLH power prices in 2023 which were \$85.51/MWh and \$81.12/MWh at Mid-C and 4C, respectively. Similarly, between 2016 and 2020, the average monthly gas price at the Opal gas trading hub was \$2.51/MMBtu and at the Sumas gas trading hub, \$3.19/MMBtu. This is compared to the average monthly gas prices in 2023 which were \$4.70/MMBtu and \$4.22/MMBtu at Opal and Sumas, respectively. Reduced coal generation increased purchased power expense and increased natural gas fuel expense due to the need for replacement power.

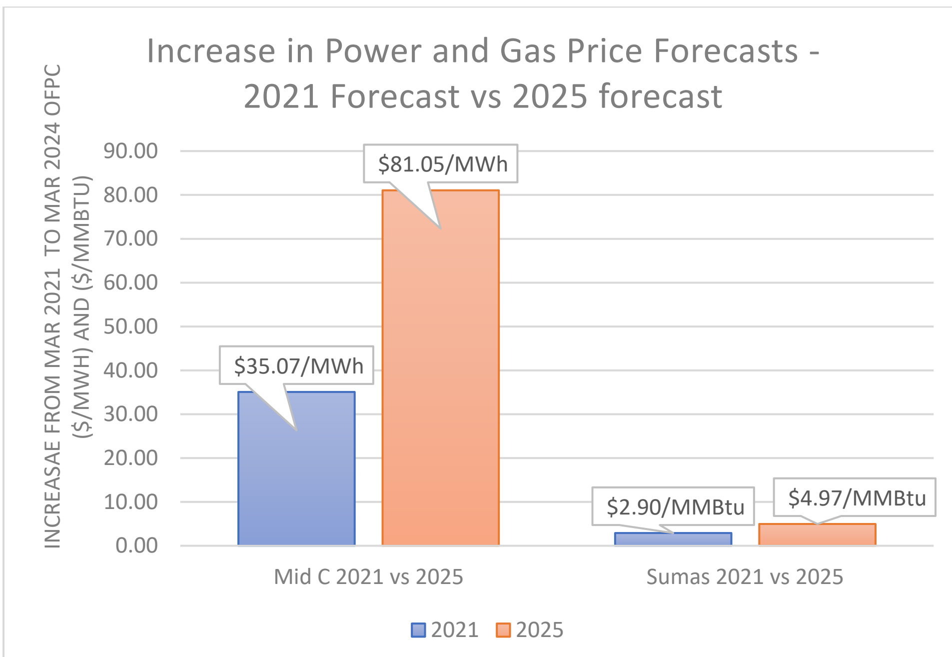
Additionally, the impacts of the Washington Cap and Invest Program increased NPC through increased expenses related to the procurement of greenhouse gas ("GHG") allowances for the out-of-state export of energy from the Chehalis gas plant, physically located in Washington. The associated increase in 2023 NPC was $42 million on a total-Company basis. Of note, the absence of any generation from the Chehalis plant would result in an increase to NPC, relative to the status quo of the Washington Cap and Invest Program, due to replacement energy being sourced from market purchases, which are more expensive than the cost of Chehalis' fuel and GHG allowances combined.

Q. Please generally describe the changes in 2025 NPC compared to the 2021 NPC from the 2021 GRC.

A. The NPC forecast from the 2021 GRC used a March 31, 2021 vintage OFPC to set the price expectations for a calendar year 2021 NPC forecast. Compared to calendar year 2025 price forecasts using a March 29, 2024 vintage OFPC, average power market prices at the Mid-Columbia power trading hub increased by 131 percent and average natural gas fuel market prices at the Sumas gas trading hub increased by 71 percent. The changes are illustrated in Figure 'OFPC' below. As a result of increase in prices and other substantive changes to the 2025 landscape, which I discuss in more detail below, **total-Company NPC** increased by approximately $15.78/MWh, or 67 percent, from the 2021 GRC forecast of $23.41/MWh to the current weather normalized GRC forecast of $39.19/MWh.

On an Idaho-allocated basis, the Company's weather normalized NPC as modeled for the NPC test period in this case have increased by $14.80/MWh, or 60 percent, from the 2021 GRC forecast of $24.54/MWh to the current weather normalized GRC forecast of $39.34/MWh.

Figure OFPC



Q. What actions have the Company taken to lower NPC?

A. The Company has implemented a number of initiatives to lower NPC. Prime examples of these initiatives are as follows:

1. Participation in the Western Energy Imbalance Market ("WEIM"). The Company has been an active participant in the WEIM since its inception in 2014 and has realized substantial benefits, helping to

drive NPC downwards. From the prior GRC to 2023 the Company realized an annual average of $147 million in WEIM benefits.[8]

2. Participation in the Extended Day-Ahead Market ("EDAM"). The Company announced in 2022 that it will join the California Independent System Operator's EDAM.[9] Similar to the WEIM, the EDAM will leverage a diverse pool of participating utilities, creating a region-wide day-ahead market, to lower the Company's NPC. Preliminary analysis indicates that the Company may realize savings of up to $181 million per year,[10] which are incremental to (not double counting) the current NPC benefits realized through WEIM participation.

3. Resource Expansion – Post 2021 the Company has procured and repowered a number of owned wind facilities (with marginal costs of $0/MWh) that drive NPC down. Concurrently and synergistically, the Company has increased investment in transmission expansion in order to facilitate the transfer of the aforementioned $0/MWh energy to the wider system. These new wind and transmission assets have driven NPC down by $87 million for the NPC test period.

IV. REGIONAL MARKET PRICE INCREASES

Q. Why have regional power and gas market prices increased to such extraordinary highs since the prior GRC?

A. Regional power market prices are driven primarily by regional gas market prices which are in turn primarily driven by natural gas fuel prices. Since March 2021 (the vintage of the OFPC used in the 2021 GRC filing), natural

[8] https://www.westerneim.com/Pages/About/QuarterlyBenefits.aspx.
[9] https://www.pacificorp.com/about/newsroom/news-releases/EDAM-innovative-efforts.html; https://www.caiso.com/Documents/extended-day-ahead-market-edam-fact-sheet.pdf.
[10] https://www.brattle.com/wp-content/uploads/2023/04/Brattle-EDAM-Simulations-PacifiCorp-Results.pdf.

gas prices have seen extraordinary year-over-year increases, as detailed below.

Q. Why have natural gas fuel prices seen extraordinary increases since the March 2021 natural gas price *forecast*?

A. Drivers of natural gas price increases in the 2025 forecast relative to the *forecast* created in the first quarter of 2021 are: (1) the conflict in Ukraine which decreased European availability of natural gas, previously sourced from Russian imports. With decreased European supply, the associated European demand turned to U.S. domestic supply to fill the gap and the increased competition over domestic supply drove regional natural gas fuel prices upwards; and (2) expectations of increased natural gas exports to Mexico and an uptick in natural gas consumption in the power sector. The expected increase in gas demand in the power sector can be linked to substantial backlogs of renewable energy projects currently in interconnection queues across the region. Natural gas pipeline exports to Mexico are anticipated to grow in response to increased power demands and expanding liquid natural gas ("LNG") export capacities. This increase in natural gas fuel prices correspondingly increases regional gas market prices and regional power market prices, in that order.

Q. What is the impact of increased natural gas fuel prices on 2025 NPC?

A. NPC decreased by $104 million when the current 2025 forecast gas prices were replaced with the 2021 forecast gas prices used in the prior GRC, under the weather normalized modeling scenario.

Q. Why has renewable resource integration experienced delays relative to prior expectations?

A. Global supply chain constraints delayed production and transportation of key components and equipment necessary for renewable resource construction across the nation. Furthermore, increases in the prices of key renewable resource construction commodities such as lithium, nickel, and copper, as well as increases in labor costs and interest rates, exacerbated the issue. Lastly, substantial backlogs of renewable energy projects currently in interconnection queues across the region delay the integration of renewable resources into the western interconnection.

Q. How have renewable resource integration delays impacted regional power market prices?

A. In resource planning at the regional level, renewable resource integration is expected to partially offset the impact of thermal plant retirements on an energy basis. In the short term, as the integration of these renewable resources are delayed, thermal plant retirements continue on schedule. The resulting energy shortfall decreases supply without any associated decrease in demand (load). Consequently, this triggers an incremental energy price rise across the competitive regional power markets which is additive to the exacerbation caused by natural gas fuel price increases.

Q. What is the impact of increased power prices on 2025 NPC?

A. NPC decreased by $304 million when the 2025 forecast power prices were replaced with 2021 forecast power prices from the March 2021 OFPC used in the prior GRC, under the weather normalized modeling scenario.

Q. Have these global events impacted coal supply and associated coal fuel prices?

A. Yes. Because of higher regional natural gas market prices and delays in renewable resource constructions, coal generation would be expected to increase, all other things equal. This increase in the demand for coal pressures domestic coal supply in the short term, resulting in higher coal fuel prices, which in turn drive regional power market prices higher. This situation is further exacerbated by coal supply challenges, discussed in more detail below. This increase in regional power market prices is additive to the increase caused by natural gas fuel price increases and additive to the increase caused by delays in renewable resource integration.

Q. What is the impact of increased coal fuel prices and new coal supply agreements on 2025 NPC?

A. The NPC impact is a $280 million increase, under the weather normalized modeling scenario, calculated by replacing current coal assumptions with coal volumes and prices prior to the increased fuel prices and new supply agreements. These changes to coal supplies are discussed in more detail below.

Q. Please elaborate on further drivers of regional power market price increases.

A. A long-term drought, dating back to the 2019-2020 winter, continues across parts of the Pacific Northwest and the consequent decrease in expected hydroelectric generation (currently 25 percent lower than the 10-year average at the regional level) diminishes the expected regional energy supply.

Furthermore, calendar years 2020, 2021, 2022 and 2023 have seen an increase in abnormal/extreme weather events that have resulted in higher-than-expected load during stressed system conditions, and this trend has set expectations amongst market participants for similar conditions in 2024 and 2025. Therefore, many utilities across the region have revised their expectations of load profiles upwards and this limits excess supply offered into the regional power markets.

These two weather-based drivers increase regional power market prices and both are additive to the increase caused by natural gas fuel price increases, additive to the increase caused by delays in renewable resource construction and additive to the increase caused by increased competition for coal supply.

V. POLICY AND OPERATIONS IMPACT TO NPC

Q. What policy or operations changes are forecast to have a substantial impact on 2025 NPC as compared to the prior GRC?

A. There are three, which are: 1) the introduction of a dispatch adder impacting generation at Chehalis; 2) decreased hydroelectric generation resulting from the deconstruction of hydroelectric facilities along the Klamath river; and (3) coal supply challenges.

A. The Washington Cap and Invest Program

Q. How does the WA-GHG Program impact the Company's load service in Idaho?

A. The WA-GHG program requires that the Company purchase GHG allowances for any GHG emissions output within the state of Washington associated with energy exported outside the state of Washington. The only source of GHG emitting energy owned by the Company in the state of Washington is the Chehalis gas-fired plant. For all energy exported out of Washington from the Chehalis plant, there is an associated GHG cost proportionate to the energy exported. Therefore, for all energy allocated to Idaho from the Chehalis plant, there is an incremental $/MWh cost based on the GHG allowance price for the NPC test period.

Q. What is the GHG allowance price applied to the Chehalis plant for this NPC test period?

A. The GHG allowance price is currently estimated at $11.14/MWh for calendar year 2025 based on auction results from March 6, 2024.

Q. How is the WA-GHG program similar to other Commission approved programs?

A. The WA-GHG program is a program that assesses a charge per MWh of energy produced from certain types of resources located in Washington state. From a cost perspective, the impact of this program on the Company's service territory is identical to the impact of costs associated with initiatives like wind taxes and coal fuel taxes that increase Company NPC.

Q. What is the impact to NPC from this program?

A. The impact of this program is an increase of $29 million. This increase is driven by the cost of GHG allowances and increased market purchases to cover generation reduction at the Chehalis plant.

B. <u>Hydroelectric Generation Reduction</u>

Q. How much has hydroelectric generation decreased between the 2021 GRC and this current filing?

A. The forecast for calendar year 2025 hydroelectric generation has decreased by approximately 663,120 MWh (19 percent) as compared to the calendar year 2021 forecast from the 2021 GRC.

Q. Why has hydroelectric generation decreased by 19 percent?

A. A long-term drought, dating back to the 2019-2020 winter, continues across parts of the Pacific Northwest (current hydroelectric generation is 25 percent lower than the 10-year average at the regional level) and is picked up in the normalized hydroelectric generation forecast. Furthermore, the removal of four Company-operated hydroelectric projects[11] along the Klamath river contribute to this decrease. These projects totaled approximately 180 MW of capacity and have ceased generation.

Q. What is the impact to NPC of the long-term drought as well as the hydroelectric projects' removal?

A. The impact is an increase of $29 million. This increase

[11] J.C. Boyle, Copco 1, Copco 2, and Iron Gate hydroelectric projects.

is driven by increased market purchases to cover the generation reduction.

C. Coal Supply Challenges

Q. What changes are there to projected coal supply in this GRC?

A. In 2022 through 2024, the coal market experienced strained conditions. The unprecedented increase in coal prices, instability in coal supply and overall market fluctuations have caused adverse impacts to the Company and other large consumers. This negative impact is due to multiple factors, including but not limited to: (1) increased coal demand due to high domestic natural gas prices; (2) low inventories at coal-fired power plants; (3) increased demand abroad for coal exports; (4) international and domestic supply chain constraints; (5) labor and material shortages; and (6) weather events and general market inflation.[12]

Moreover, the Lila Canyon mine fire removed approximately 25 percent of Utah coal production and disrupted the same portion of the Company’s coal supply needs in Utah.[13] On November 18, 2023, the Company was informed that the Lila Canyon mine will not reopen and

[12] *In the Matter of PacifiCorp d/b/a Pacific Power, 2024 Transition Adjustment Mechanism*, Exhibit PAC/200, Owen/3-7 (April 3, 2023).
[13] *In the Matter of PacifiCorp d/b/a Pacific Power, 2024 Transition Adjustment Mechanism*, Exhibit PAC/200, Owen/4 (April 3, 2023).

will be permanently closed. The closure of Lila Canyon created a significant coal production shortfall in Utah, beginning in 2022, and will continue to have negative impacts to all large consumers, including the Company.

In addition to the Lila Canyon mine issues in Utah, coal suppliers continue to experience issues relating to unfavorable geologic and mining conditions, delays and pressure relating to securing federal mining leases, limited availability of trucking and railway transportation for coal, long lead-times for procurement of necessary mining equipment, and limitations in availability of financing, which has put them at an increased risk of becoming insolvent.

Q. What is the impact to NPC from these coal supply challenges?

A. As mentioned above, the impact of these coal supply challenges is an increase of $265 million on a total-Company basis. This increase is driven by increased natural gas generation and increased market purchases to cover the coal generation reduction.

Q. What steps has the Company taken to alleviate these coal supply challenges?

A. The Company focuses on achieving its target coal supply at a reasonable price, along with contract terms that provide flexibility. However, because the Utah coal market has been supply constrained since 2022, the Company has had limited leverage to accomplish these goals. [redacted]

Q. How has the Company ensured a dependable and secure future coal supply for the Hunter and Huntington plants?

A. In February 2024, the Company amended the Hunter and Huntington coal supply agreements with Wolverine. The amended Hunter/Wolverine CSA [redacted]

[redacted] for the Hunter plant. Beginning in [redacted], the Hunter/Wolverine CSA amendment facilitates additional coal production through renewed operations at the Fossil Rock mine in Emery County, Utah. Deliveries from the Fossil Rock mine will begin in [redacted]. When fully operational, the Fossil Rock mine will provide [redacted] tons per year to the Hunter plant, [redacted]. The contract amendment also allows the Company to direct this coal to the Huntington plant as needed. The amended Huntington/Wolverine CSA now also allows the Company the flexibility to direct coal to the Hunter plant as needed. The Huntington/Wolverine CSA [redacted].

Q. **How does the Company plan to meet fuel supplies for its coal-fired plants in 2025?**

A. The Company employs a diversified coal supply strategy, with 84 percent of its 2025 coal requirements supplied by third-party coal supplies and 16 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.

Q. Please generally describe the coal supply arrangements across the Company's coal-fired plants for 2025.

A. The following Confidential Table 'Coal Contracts' summarizes the coal supply arrangements and costs for 2025 in comparison to the 2021 GRC:

Confidential Table Coal Contracts

Plant	Vendor	2025 Delivered Tons (millions)	2025 $/Ton	2021 $/Ton	$/Ton Change	Comments
Jim Bridger	Black Butte Coal Company	[redacted]				
Jim Bridger	Bridger Coal Company					
Colstrip	Westmoreland Rosebud Mining					
Craig	Trapper Mine					
Hayden	Peabody Coal Sales					
Hunter	Bronco Utah Operations					
Hunter	Wolverine Fuel Sales					

Plant	Vendor	2025 Delivered Tons (millions)	2025 $/Ton	2021 $/Ton	$/Ton Change	Comments
Hunter	Gentry Mountain	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Huntington	Wolverine Fuel Sales	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Dave Johnston	Peabody Coal Sales (Caballo 8500)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Dave Johnston	Peabody Coal Sales (Caballo 8400)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Dave Johnston	Arch Coal Sales	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Dave Johnston	Open positions	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Naughton	Kemmerer Operations	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Wyodak	Black Hills -Wyodak Resources	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

D. Cumulative Impact

Q. What is the combined impact of the various changes on NPC?

A. Total-company 2025 weather normalized NPC decrease by a total of $508 million when 2025 assumptions were replaced with the prior GRC’s 2021 forecast assumptions, for power prices, fuel prices, and policy and operations assumptions.

Put another way, 2025 weather normalized NPC as modeled in Aurora is $1.766 billion when assuming commodity prices, fuel supply, and polices and operations that were expected for 2021 in the prior GRC. This accounts for a majority of the increase between the 2021 NPC actuals (which the prior GRC attempted to forecast) and the current 2025 weather normalized NPC forecast.

VI. NPC AND TRANSITION BETWEEN MODELS

Q. Did the Company transition to Aurora to calculate NPC?

A. Yes. The Company has used GRID since it was deployed in 2008 but discontinued its use for NPC filings in 2021 and transitioned to Aurora, produced by Energy Exemplar. Aurora provides additional functionality, increases usability, as well as increases compatibility with the Company's information technology.

To date, the Company has filed NPC forecasts using Aurora in California, Oregon, Washington, and Wyoming. Additionally, Aurora includes certain functionality necessary to perform the allocation of state-specific NPC for ratemaking purposes in the post-interim period as contemplated in the 2020 PacifiCorp Inter-Jurisdictional Allocation Protocol ("2020 Protocol").[14]

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

A. Yes. The general approach to the calculation of NPC is the same, but the model has changed from GRID to Aurora.

A. <u>An Overview of Aurora</u>

Q. How does Aurora work?

A. Similar to GRID and other production cost models, the objective of Aurora is to meet the projected load at the lowest possible cost. This is accomplished by simulating the dispatch of available resources, both supply-side and demand-side, within their physical constraints, economic constraints, transmission constraints and emissions constraints, as well as adhering to the profiles of the load requirements to produce a cost minimizing simulation where demand and supply are balanced.

Like GRID, Aurora's simulations take as input information such as system load, reserves, wholesale sales and purchase contracts for electricity, natural

[14] *In the Matter of Rocky Mountain Power's Application for Approval of the 2020 PacifiCorp Inter-Jurisdictional Allocation Protocol.* Case No. PAC-E-19-20. Order No. 34640 (April 22, 2020); *In the Matter of Rocky Mountain Power's Petition for Approval of an Extension of the 2020 Inter-Jurisdictional Allocation Protocol.* Case No. PAC-E-23-13 Order No. 35984 (Nov. 2, 2023).

gas and wheeling, market prices for electricity and natural gas, fuel expenses, transmission topology, and the characteristics and availability of the Company's supply-side and demand-side facilities.

Q. How does Aurora compare to GRID?

A. The model logic is conceptually the same between Aurora and GRID; both models aim to minimize costs to serve obligations, under various constraints. While the categories of inputs are mostly the same between the two models, Aurora has more parameters to model resources and offers more flexibility to model more types of resources.

Q. What are some of the modeling improvements gained by moving to Aurora?

A. Aurora co-optimizes (as opposed to sequentially optimizing) energy and ancillary service requirements, allowing the model to create precise NPC forecasts that simultaneously satisfy all load and reserve obligations while appropriately reflecting the forecasted NPC. In addition, Aurora can receive more than one incremental price for the purpose of forecasting dispatch of coal-fired resources and can recognize and optimize around volumetric constraints in each price tier (minimum take volumes, volume limits, etc.). Furthermore, Aurora allows for the modeling of emissions constraints and associated emissions rates and emissions prices, allowing the Company to integrate compliance with various emissions constraints within the model.

Q. What is the process by which the Company validated the use of Aurora as compared to GRID?

A. Both GRID and Aurora are production cost optimization models that use mathematical optimization techniques with similar inputs that attempt to satisfy the Company's load and reserve obligations at minimum cost. Aurora has more features and flexibility, but both models are based on the same underlying economic principles. The validation process started with the understanding that the results from the two models will be different. Based on that understanding, the process included steps such as: 1) verify if the outputs of non-dispatchable resources match the inputs, and the outputs match between Aurora and GRID; 2) refine input parameters in Aurora that are either not available in GRID or have a different impact on optimization; and 3) research the reasons why the same dispatchable resources with generally the same inputs produce different results between Aurora and GRID. And, finally, the total NPC from the two models are compared and reviewed for reasonableness which includes ensuring that the deviation in the total NPC is within a reasonable range.

Q. Why would the same resources produce different results from Aurora and GRID when they have the same inputs?

A. The inputs in the two models are not the same because Aurora allows for more modeling parameters and more levels of granularity. Additionally, Aurora co-optimizes energy and ancillary service requirements by using an advanced mixed integer program, whereas GRID sequentially optimizes one requirement then the other. Furthermore, Aurora uses its mixed integer program for commitment (startup/shutdown) decisions whereas GRID applies relatively basic static optimization techniques. Differences in the optimization techniques lead to different unit commitments and different unit dispatches based on the prevailing economics.

Q. Can you provide the results of the Company's validation process?

A. Yes. Please refer to Exhibit No. 24 and Exhibit No. 25, which contain the Aurora and GRID NPC test reports that the Company used to validate Aurora. The test reports show that there was less than 0.8 percent variation between the NPC calculated with GRID as compared to Aurora.

Q. While the overall variation was low, there may have been greater variation in individual resources when comparing the two test reports. Can you comment?

A. Yes. As I discussed above, there are differences between Aurora and GRID with regards to optimization techniques. In addition, each model contemplates different levels of granularity of inputs. Those two in combination will result in different dispatch of resources, and different balancing transactions. Therefore, the validation process compared the overall outcome of the NPC test report.

Q. Would running GRID with the inputs used for this rate case provide additional useful information regarding the validation of the Aurora model?

A. No. As described above, the ability of each model to accept different inputs and the internal optimization techniques differ between the models even though the underlying principles are similar. Furthermore, there are inputs in Aurora that are not capable of being accepted by GRID (example, emissions constraints and tiered price/volume coal contracts). There is no reasonable expectation that the model results would be the same or would provide additional insight, making the proposed comparison a futile exercise. Additionally, the Company has already benchmarked Aurora against GRID and found that the overall NPC results exhibited a tolerable variance between the two models when limiting the inputs to those capable of being simultaneously accepted by both models.

Q. Has the Company performed any other benchmark of Aurora?

A. Yes. The Company performed a backcast of calendar year 2020, wherein 2020 historical inputs were fed into Aurora, and then the 2020 calendar year was "forecast" ("backcast") to assess whether the resulting NPC would align with the actual NPC observed in 2020. The 2020 backcast, as well as a write up analyzing its results, are provided in Confidential Exhibit No. 26.

Q. What do the results of this backcast show?

A. The backcast demonstrates that Aurora produces accurate results. 2020 actual NPC was $1.511 billion and Aurora's backcast of 2020 produced NPC of $1.453 billion, an under-forecast of 3.9% and a demonstration of the model's reasonableness.

B. Inputs and Adjustments in Aurora

Q. How are inputs treated differently between the two models?

A. Aurora incorporates many of the same inputs that GRID formerly considered in its optimization. Consequently, many of the same workpapers are still in use, but those inputs flow through Aurora input workbooks to be formatted for acceptance by the newer model. For inputs that are distinct from their GRID equivalents (coal prices, for example), entirely new modeling approaches were employed to take advantage of the additional flexibility offered by Aurora. There are also inputs that are the same but require slightly modified calculations to account for the treatment given to those inputs in Aurora (unit minimum operating levels and thermal outage rates, for example).

Q. How is the output from Aurora incorporated into Idaho-allocated NPC?

A. The Aurora model results are used to create a total-Company NPC forecast and the total-Company NPC report is similar to the report that has been used in the past. Those results are then allocated by Company witness Shelley E. McCoy according to the 2020 Protocol to arrive at an Idaho-allocated NPC forecast.

Q. Please describe any other significant modeling differences between GRID and Aurora.

A. As mentioned above, Aurora accounts for unit minimum operating levels ("unit minimums") and equivalent outage rates ("EOR") differently, and both required formulaic updates because of differences in the modeling of unit availabilities. Aurora scales both the unit maximum capacity and the unit minimum in response to a derate because Aurora requires unit minimums to be expressed as a percentage of unit maximum capacity. In GRID, unit minimums were required to be expressed in absolute megawatt ("MW") amounts. Prior to settling upon a revised approach to the calculation of these inputs, the Company observed many hours where the generation forecast showed output below a unit's minimum. A relatively straightforward solution was adopted by the Company that only required the calculation and input of an hourly unit minimum percentage (percentage of unit capacity) timeseries to account for derates. To avoid the possibility of infeasible operations, another modification was made to the EOR to remove units from service (that is, the EOR was set to 100 percent) whenever the available capacity slipped below the unit minimum. In addition, Aurora can receive more than one incremental price for the purpose of forecasting dispatch of coal fired resources and can recognize and optimize around volumetric constraints in each price tier (minimum take volumes, volume limits, etc.). That modeling improvement allows the Company to more easily arrive at a forecast of coal unit dispatch that is subject to volumetric constraints and tiered pricing across a range of consumption levels.

Q. Is the Day-Ahead/Real-Time ("DA/RT") Adjustment needed in Aurora?

A. Yes. The DA/RT adjustment is used to better reflect system balancing costs that are not fully captured in the Aurora model. This adjustment indicates a deviation of actual market prices available to the Company in real operations from the historical monthly trading-hub-indexed market prices. The DA/RT adjustment is the result of multiple variables within a dynamic system in which the Company has historically bought more during higher-than-average price periods and sold more during lower-than-average price periods.

To better reflect the market prices available to the Company when it transacts in the real-time market, the Company includes separate prices for forecast system balancing sales and purchases in Aurora. These prices account for the historical price differences between the Company's purchases and sales compared to the monthly average market-indexed prices.

Additionally, like GRID, the volume of system balancing transactions generated by Aurora do not reflect the volumetric inefficiencies and associated costs of the operational practice of transacting on a quarterly, monthly, daily and real-time basis. Because Aurora balances the Company's load and resources to fractions of a megawatt 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 quarterly, monthly, daily, and real time horizon basis.

For instance, if the Company buys a monthly product that aligns with the Company's average open position for the month, one can expect that approximately 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 real-time.

Finally, buying or selling standard block products 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.

VII. MODELING IMPROVEMENTS TO THE NPC FORECAST

Q. Why are modeling improvements necessary?

A. Modeling improvements align the NPC forecast with operational realities in order to produce an accurate forecast.

Q. What modeling improvements have been implemented since the 2021 GRC?

A. The Company has incorporated the following improvements since the last rate case:

- The DA/RT market price adder will be changed from a flat value to a percentage.
- Trapped energy will be appropriately substituted for curtailment of generation to reflect actual operations.
- The maximum capacity of certain thermal generation units will be updated to reflect ambient temperature derates to unit capacity during the summer months.
- The NPC forecast will simulate power hedging transactions in order to maintain compliance with the Company's current Energy Risk Management Policy.
- The calculation of capacity limits on modeled market sales have been updated, and no longer include power hedging transactions.

A. DA/RT Adjustment - Price Component

Q. Please explain how the price component of the DA/RT adjustment operates.

A. The price component of the DA/RT adjustment addresses the costs incurred by the Company as a result of multiple variables within a dynamic system in which the Company has historically bought more during higher-than-average price periods and sold more during lower-than-average price periods.

To better reflect the market prices available to the Company when it transacts in the real-time market, the Company includes separate prices for forecast system balancing sales and purchases in Aurora. These prices account for the historical price differences between the Company's purchases and sales compared to the trading-hub-indexed market prices. Previously these prices were calculated by adding or subtracting a flat dollar amount to the hourly scaled prices from the OFPC.

Q. Has the Company proposed a refinement to the price component of the DA/RT in this case?

A. Yes. The Company proposes to change the DA/RT adjustment's price component from a flat dollar adder to a percentage-of-market-price adder.

Q. Please explain how changing the DA/RT adjustment's price component from a flat value to a percentage of market price results in a DA/RT adjustment that is more reflective of actual operations.

A. Changing the price calculation to a percentage of the market prices aids in accounting for the volatility caused by prices and system conditions not captured in day-ahead transactions. Take, for example, a $5 price adder in an hour when the market price is $25. This resolves to a 20 percent price adder. But using the $5 price adder when market prices are $75 would fail to account for the system and market conditions during that hour. Using a 20 percent price adder during hours when market price is $75 would yield in a $15 price adder, which is more reflective of the system conditions. A key benefit of using a percentage adder is that it allows the modeling to capture intra-monthly variability. Subsequently, this is a significantly more accurate representation of real operating conditions experienced by the Company.

Q. Why has the transition to Aurora not resolved the need for a DA/RT price component?

A. As noted above, the basis of the DA/RT price component is founded in the historical price differences between the Company's purchases and sales as compared to the monthly average market prices. The fact that there are historical price differences between the Company's purchases and sales as compared to the monthly average market prices is agnostic to the model used to forecast Company purchases and sales. Therefore, the transition to Aurora has not resolved the basis for the DA/RT price component.

Q. How does a percentage adjustment better capture intra-month price variability as compared to a flat dollar adjustment?

A. Below, I provide analysis on the drivers of the DA/RT price component, including a discussion of historical hourly scaled monthly average market prices as compared to historical hourly scaled Company purchases and associated purchase prices across four years of historical data from 2020 to 2023. This analysis shows that the refinement proposed by the Company more accurately accounts for intra-month price variability in the context of the historical data.

Q. Why is it important to focus on Company purchases instead of Company sales?

A. Across the historical period, the total net peak expense incurred from Company purchases is approximately [redacted] greater than the total net peak revenues gained from Company sales. Confidential Figure 'DART Net' provides an illustration of this along with the average four-year historical hourly shape of purchase volumes, sales volumes, purchase expenses and sales revenues. This data, along with the observation that throughout the historical period the Company is a net purchaser (importer) on a dollar and volume basis and that Aurora has no market caps on purchases highlights the outsized importance of purchased power and its attendant costs.

Confidential Figure DART Net

[redacted]

Q. What does the historical data show when comparing market prices to the Company's purchases?

A. Confidential Figure 'DART Adder' uses data from 2020 to 2023 to create two curves—one illustrating hourly scaled average market-indexed prices and one illustrating hourly scaled average Company purchase prices. The difference between the curves is an illustration of the DA/RT price component. The concept of intra-month price variability is exhibited by the change in price levels across the day for the hourly scaled average market-indexed prices as compared to the hourly scaled average Company purchase prices. This price variability is set forth numerically in Confidential Table 'DART Adder', which shows the numeric difference between the two curves.

Confidential Figure DART Adder

[redacted]

Confidential Table DART Adder

Hour Ending	Average Historical DA/RT *Price Component's* Adder
1	[redacted]
2	
3	
4	
5	
6	
7	
8	
9	
10	
11	
12	
13	
14	
15	
16	
17	
18	
19	
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21	
22	
23	
24	

Q. Why do you refer to the variability as "intra-month" when the data appears to focus on variability within a day?

A. It is important to recall that the OFPC uses monthly prices, which are then scaled down to hourly prices. So intra-month price variability is exhibited as hourly price variability within each day of the month. In my testimony above and as illustrated in Confidential Figure 'DART Adder', this intra-month price variability is presented as average hourly price variability across the four-year historical period for the average day.

Q. The DA/RT price component has historically been a flat dollar amount applied to the purchase and sales price. Does the historical data support this approach?

A. No. The historical data in Confidential Figure 'DART Adder' and Confidential Table 'DART Adder' shows intra-month variability in the DA/RT price component (i.e., the variability between the hourly scaled average market-indexed prices and the hourly scaled average Company purchase prices) is not constant across the day; the difference is generally greater as the price increases. If historical market prices supported the DA/RT price component as a flat dollar amount, then the historical values in Confidential Table 'DART Adder' would not exhibit change across the day but rather show consistency.

Confidential Figure 'DART Percentile' illustrates this variability in the actual historical DA/RT price component as compared to an illustration of a flat adder.

Confidential Figure DART Percentile

[redacted]

Q. Is Confidential Figure 'DART Percentile' a visual of historical market price curves in comparison to a flat DA/RT price component?

A. No. Confidential Figure 'DART Percentile' is a visual of what the historical DA/RT price component is, based solely on the historical relationship between actual market prices and actual Company purchases along with a comparison to a hypothetical flat adder that is separated into heavy load hour ("HLH") and light load hour ("LLH") components. Confidential Figure 'DART Percentile' is a visual of Confidential 'DART Adder' along with a comparison to a hypothetical flat adder that is separated into HLH and LLH components. Confidential Figure 'DART Percentile' is not a visual of a market price curve, even though it looks similar.

Q. Does the historical data support the usage of a percentage adder to more accurately account for intra-month price variability?

A. Yes. As illustrated in Confidential Figure 'DART Adder' and in Confidential Table 'DART Adder', as the historical average market-indexed price increases, the spread between the historical average market-indexed price and the historical average buy price increases as well. This suggests that a percentage adder is more suitable for capturing the historical interplay between monthly average market prices and Company purchase prices. As illustrated in Confidential Figure 'DART Percentile', the historical data definitively does not suggest that a flat adder is appropriate for capturing this intra-month dynamic. This means that the Company's refinement to the DA/RT price component is a more accurate representation of the difference between average market prices and the Company's transaction prices. Because the purpose of the DA/RT price component is to reflect this difference, the Company's refinement is appropriate and more accurate.

Q. Please quantify the NPC impact of this adjustment.

A. The NPC impact of this adjustment is an increase of $12 million.

B. Trapped Energy

Q. Please explain the Company's trapped energy concept.

A. Primarily, trapped energy is a modeling concept only and does not exist in actual operations. It represents any excess generation that cannot be used to serve load due to transmission constraints or system-level oversupply. Because of limited transmission and the need for supply and demand to always be balanced, the trapped energy is captured within a modeled trapped energy zone and serves "pseudo load" that is regulated by a "pseudo generator" with an infinite ramp rate ("pseudo" - i.e., the load and generation in the trapped energy zone are also modeling constructs that do not exist in actual operations).

Q. Why was the trapped energy modeling concept necessary in GRID?

A. Conceptually, the trapped energy zones allow for a feasible model solution in the event of an inability to maintain the supply/demand balance when there is excess supply However, the primary function of trapped energy zones in prior GRID NPC simulations was to allow for company owned production tax credit ("PTC") eligible wind to be modeled with a reasonable degree of accuracy. Due to an inability in GRID to model resources with a negative dispatch price (representative of PTCs, in the case of wind), these wind resources could not provide the proper price signal to the model and therefore could not be accurately represented within GRID's resource stack. As a work-around, the wind resources were simulated as must run resources and all excess wind generation within a transmission constrained area was funneled into a trapped energy zone.

Q. How was energy in the trapped energy zone valued?

A. In the past, the Company valued trapped energy at 75 percent of market prices, which led to overstated sales revenue. Since this trapped energy concept does not exist in actual operations, the value of trapped energy should be zero.

Q. How does Aurora eliminate the need for trapped energy zones?

A. Aurora allows for wind curtailment while recognizing the PTC benefits that produce an implied negative dispatch cost. By placing the wind resources at the bottom of the resource stack and allowing the model to dispatch the wind resources downwards when there is more energy from the wind resources than there is transmission to move the energy to load, or when the ramp capability of dispatchable resources are unable to follow the hour-to-hour ramps in wind generation, the NPC simulation dispatches (curtails) the wind downwards and appropriately reflects how wind resources are actually operated and actually dispatched downwards in actual operations.

Q. Please quantify the NPC impact of allowing wind to be curtailed in similar fashion as actual operations.

A. The NPC impact of allowing for realistic wind curtailment is an increase of $34 million driven by: 1) a reduction in pseudo-wholesale sales revenue earned from the sales of energy derived from a modeling construct that does not exist in actual operations; and 2) incremental wind curtailments to maintain the supply/demand balance within a transmission congested region when considering that any sharp hour-to-hour ramps in wind generation are unable to be completely balanced by relatively slow ramping coal units present in the region.

Q. Please quantify the impact of valuing the trapped energy zone at zero percent of market prices after allowing for wind curtailments.

A. The impact to NPC is $0 since after allowing for appropriate wind curtailment the trapped energy modeling construct has been removed. That is to say, there are no more trapped energy zones modeled in this filing.

C. Thermal Attributes

Q. What updates did the Company make to the characteristics of some of its thermal resources?

A. Thermal plant capacities have been previously calculated as the average of historical capacity over general summer and winter periods. For some thermal plants, performance decreases as the ambient temperature increases. As temperatures are historically hotter during the summer months of June through September, the generation output from these thermal plants decreases during those months. To account for this operational constraint, the Company updated the maximum capacities at certain plants during each summer month from June through September. Exhibit No. 27 and Exhibit No. 28 demonstrate the degradation in generation capacity that results from increased temperatures. The exhibit graphs were provided to the Company by the General Electric Company and by Siemens Energy AG.

Q. Please explain how this adjustment results in more accurate forecast NPC.

A. Because maximum capacities of some thermal plants are reduced as a result of increased temperatures in the summer, not adjusting the capacity during the summer months based on these conditions would result in Aurora overstating plant capacity and generation output, which would consequently understate the need to dispatch higher cost units or increase purchases to serve load during the summer months. Reducing generation capacity during summer based on average summer temperatures is reflective of actual ambient-temperature constraints.

Q. Please quantify the NPC impact of this adjustment.

A. The NPC impact of this adjustment is an increase of $16.9 million. This increase is driven by increased market purchases.

D. <u>Hedging Requirements</u>

Q. Please briefly provide an overview of the Company's power hedging requirements.

A. The Company revised its Risk Management Policy in 2021 with the specific and stated goal of guiding energy supply management to purchase increasing amounts of power in periods with short positions. This is intended to limit the possibility of being short during periods of peak demand and peak pricing. This revised policy imposes power hedge percentage limits that are applied independently to each side of the system, varying by quarter, and escalating as the time to delivery of power approaches. The most relevant requirement in relation to the Company's NPC forecast is the requirement that positions be hedged at a level where, on average, a minimum of 75 percent of each month’s largest generation deficit is hedged in the first quarter of the future (e.g., in December 2024 this would apply to the first quarter of 2025).

Q. In its original form, is the NPC forecast in compliance with the Company’s power hedging requirements?

A. No. Aurora is a forward-looking, optimized, deterministic dispatch model with no knowledge of the Company’s hedging requirements or how they evolve over time. While some quarters may be in compliance without this modeling improvement, that is coincidental, not an indication that the model intentionally satisfies the requirements imposed by the Company’s risk management policy.

Q. What change was made to align the NPC forecast with the Company’s power hedging requirements?

A. To reflect the fact that the Company will eventually need to hedge each quarter at a minimum average of 75 percent, additional short-term firm transactions are calculated, in quarterly 25 MW energy blocks of heavy or light load hour products, and loaded into the model to ensure that the quarterly average hedge ratio in the peak hour of each month satisfies the policy-dictated minimum requirements for the first quarter. In that way, the inputs to the model are created in a manner which recognizes that all four quarters in the NPC test period will eventually be the first quarter in actual operations and the Company will need to execute forward transactions to satisfy its hedging policy requirements.

Q. Does this change conform to the realities of actual operations?

A. Yes. As noted above, each month in the NPC test period will eventually be part of a quarter that needs to be hedged at a minimum average of 75 percent in actual operations. However, these hedges are based on forecasted prices, and to the extent that actual prices differ from the forecasted prices, the cost of hedges will be different in actual NPC; this concept holds true for the entire NPC forecast.

Q. Are these simulated hedge volumes subject to the DA/RT price component?

A. No. The prices used in the DA/RT price component are created in recognition of the fact that, in actual operations, the Company purchases at prices above the OFPC and sells at prices below the OFPC in the spot market (i.e., the day-ahead and real-time trading horizons); and Aurora's optimization is fundamentally a spot market simulation. Because this modeling update is intended to simulate forward transactions, the prices for the simulated hedges are added to the model with no price adjustment. This is reflective of the Company's transaction history, which indicates that forward hedges are executed at or about the prevailing market price at the time of execution, on average.

Q. Why was no change made to the NPC forecast for the Company's gas hedging requirements?

A. Because such a change would have no impact to the NPC forecast. Aurora does not physically balance the gas system, and the impact of gas hedges consists entirely of the mark-to-market ("MTM") value of those hedges. Were the Company to simulate gas purchases at expected market prices (i.e., the OFPC), they would show no MTM impact and additionally, the associated gas volumes are not modeled in Aurora, so there would be no change to the NPC forecast.

Q. Please quantify the NPC impact of this modeling improvement.

A. The NPC impact of this adjustment is an increase of $0.67 million.

E. Market Sales Capacity Limits

Q. What are market sales capacity limits?

A. Market sales capacity limits refer to the amount of energy that other market counterparties are willing to purchase in aggregate from the Company. More specifically, market capacity limits represent a threshold above which no one else can be found in the bilateral electricity markets to take the Company's energy at or above the Company's cost of producing that energy.

Q. Please explain what a liquid market is in the industry of today.

A. From the perspective of market sales, a liquid market is a market where the Company can find a buyer to take its excess energy whenever the prevailing market price is at or above the Company's cost of production, regardless of hour or day.

Q. Please explain why Aurora requires sales market capacity limits.

A. Like GRID before it, Aurora operates with perfect foresight and assumes near unlimited market depth and full liquidity for the markets in which the Company makes off-system sales, unless informed otherwise. Aurora would therefore allow unrealistic off-system sales at every market at any time of the day or night—an assumption that is very different from the Company's actual, historical experience. The market capacity limits inform Aurora of the limits on the depth of the markets being modeled, thereby forcing Aurora to respect those limits during the execution of its optimization algorithm.

Q. Is the Company proposing to make changes to the market sales capacity limits calculation?

A. Yes. With the inclusion of simulated hedge volumes in the NPC forecast, the Company has removed volumes related to hedges from its market sales capacity limits calculation. Furthermore, the Company is applying the market sales capacity limits to all market sales hubs within Aurora, inclusive of the Palo Verde and Mid-Columbia hubs, which did not have market capacity limits in the 2021 GRC.

Q. Why is the Company proposing to remove hedge volumes from its market sales capacity limits calculation?

A. Under the previous method, market sales capacity limits were first calculated using historical sales volumes inclusive of sales hedge volumes. Then, second, these limits were reduced by executed sales hedge volumes for the NPC test period, in order to provide for a realistic modeled estimate of spot market sales volumes (i.e., sales in the day-ahead and real-time trading horizons) plus *yet-to-be-executed* sales hedge volumes in the NPC forecast. However, since the NPC forecast is now fully hedged with simulated hedge volumes from the "Hedging Requirement" modeling update discussed above, the modeled market sales in the NPC forecast now represent only spot market sales. For this reason, the market sales capacity limits calculation now includes only spot market sales volumes (i.e., excludes all hedge volumes) in its calculation.

Q. Why is the Company proposing to apply the market sales capacity limits to the Palo Verde and Mid-Columbia hubs?

A. As demonstrated in Confidential Figure 'Market Caps' below, the volume of Company spot market sales has been in a declining trend over the past five years. Furthermore, and additionally, trading hubs in the spot market are no longer as liquid as they used to be; as demonstrated by the increased risk of energy shortfalls across the region, specifically "the risk of resource shortfalls during extreme summer weather conditions after 2024,"[15] as identified by the North American Electric Reliability Corporation ("NERC").

Q. How have the Company's spot market sales volumes been decreasing over time?

A. As can be seen in Confidential Figure 'Market Caps' below, the Company has experienced a declining trend in spot market sales volumes since 2018. After removing the hedge volumes from the market sales capacity limits calculation, in addition to applying the limits to sales

[15] North American Electric Reliability Corporation, *2023 Long-Term Reliability Assessment* at 24 (Dec. 2023) (available at- https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2023.pdf) (last visited Jan. 30, 2024).

at the Palo Verde ("PV") and Mid-Columbia ("Mid-C") power trading hubs, the forecast volumes are much closer to actuals[16] as compared to the prior calculation methodology[17] which produces demonstrably unreasonable and substantially inaccurate (high) levels of spot market sales volumes; all illustrated in Confidential Figure 'Market Caps' below.

Confidential Figure Market Caps

[redacted]

[16] Confidential Figure 'Market Caps', column "Forecast 2025 Sales".
[17] Confidential Figure 'Market Caps', column "Hedge Volumes and no PV/Mid-C Limits".

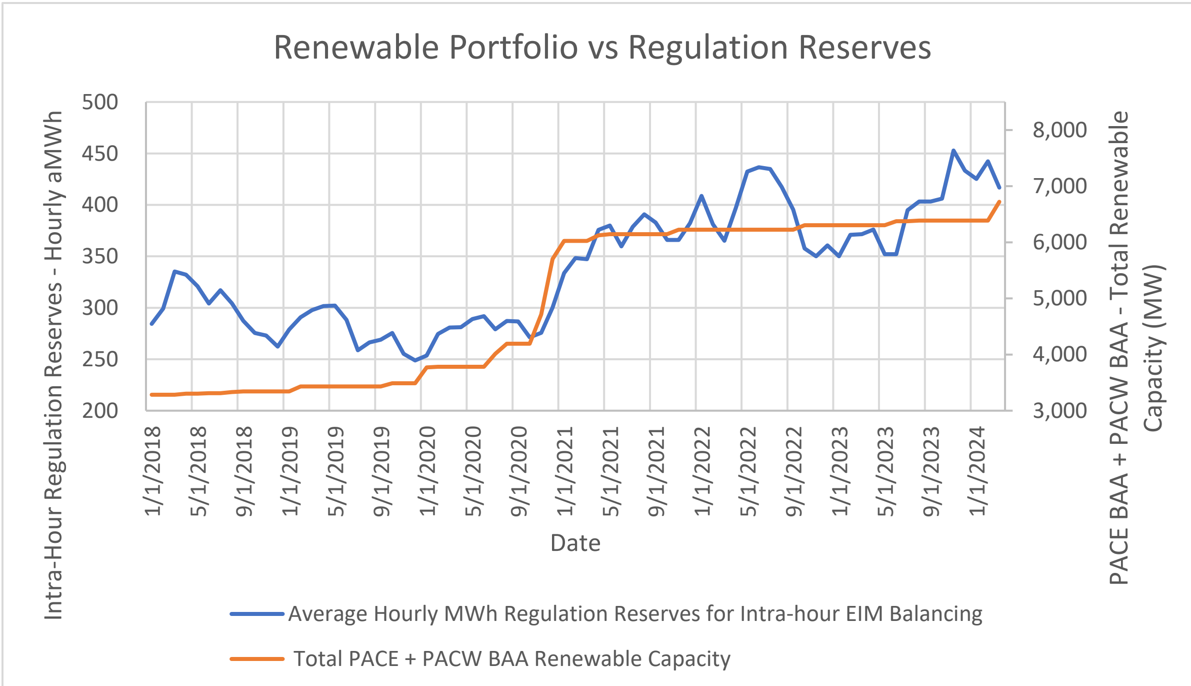
Q. What are the drivers behind this decrease in spot market sales volumes?

A. Coal supply challenges, increased regulation reserve requirements and the energy imbalance market ("EIM") are three of the drivers for this decreasing trend in spot market sales volumes.

Q. How do regulation reserves contribute to the decrease in spot market sales volumes?

A. As entities across the region integrate ever increasing numbers of variable renewable resources into their portfolio, their regulation reserve obligations increase. This relationship is illustrated in Figure 'Regulation Reserves'. As these reserve obligations increase, excess supply is diminished. This reduction in excess supply will naturally result in lower sales in the spot markets. The trend whereby variable renewable resources occupy a larger portion of entities' portfolios over time is one that will continue to increase well into and past 2025 due to various federal and state regulations.

Figure Regulation Reserves



Q. Are the regulation reserve numbers in Figure 'Regulation Reserves' representative of the Company's balancing authority reliability regulation reserve requirements?

A. No. These numbers are the EIM's calculation of regulation reserves using errors in load, wind and solar forecasts made approximately 45 minutes before the operating moment ("real-time") as compared to forecasts made approximately 10 minutes before real-time. The Company's regulation reserve requirements, subject to NERC standards and represented in the IRP's flexible reserve study, are calculated from errors in load, wind, solar and other non-dispatchable generation forecasts made approximately 107 minutes before real-time as compared to actuals (i.e., 0 minutes before real-time). As such, the trend is comparable but not the magnitude.

Q. How does the EIM contribute to diminishing excess supply?

A. With the emergence of the EIM, which now serves 80 percent[18] of the demand for electricity in the western interconnection, EIM entities face additional opportunity costs that must be contemplated in the spot market timeframes. If an EIM entity finds itself with excess supply and the expected price in the EIM is greater than the prevailing price in the spot markets, then the entity may forego selling their excess supply into the spot markets and instead set that excess supply aside for sale in the EIM. This naturally reduces sales in the spot markets.

Q. Is the Company's experience unique?

A. No. Looking at Figure 'MidC Volumes' and Figure 'PV Volumes' below, HLH volumes at the Mid-Columbia and Palo Verde power market hubs have been decreasing since 2018. This trend along with the discussion above supports the position that the Mid-Columbia and Palo Verde trading hubs are no longer as liquid as they used to be.

[18] https://www.caiso.com/about/Pages/Blog/Posts/Evolution-of-the-WEIM.aspx.

Figure MidC Volumes

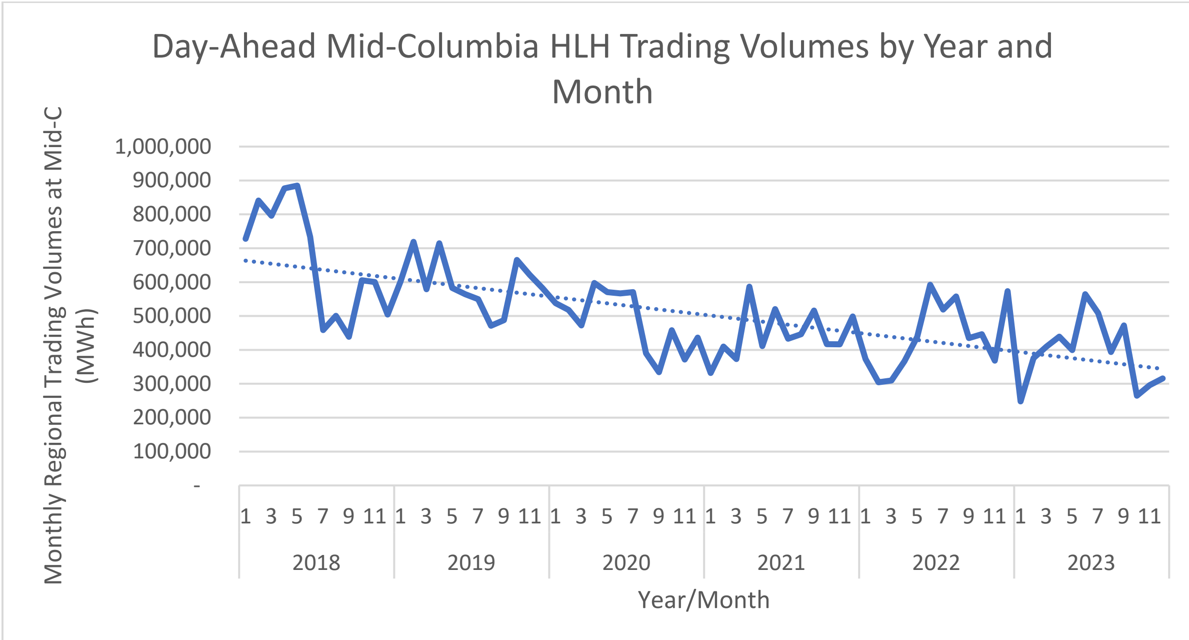
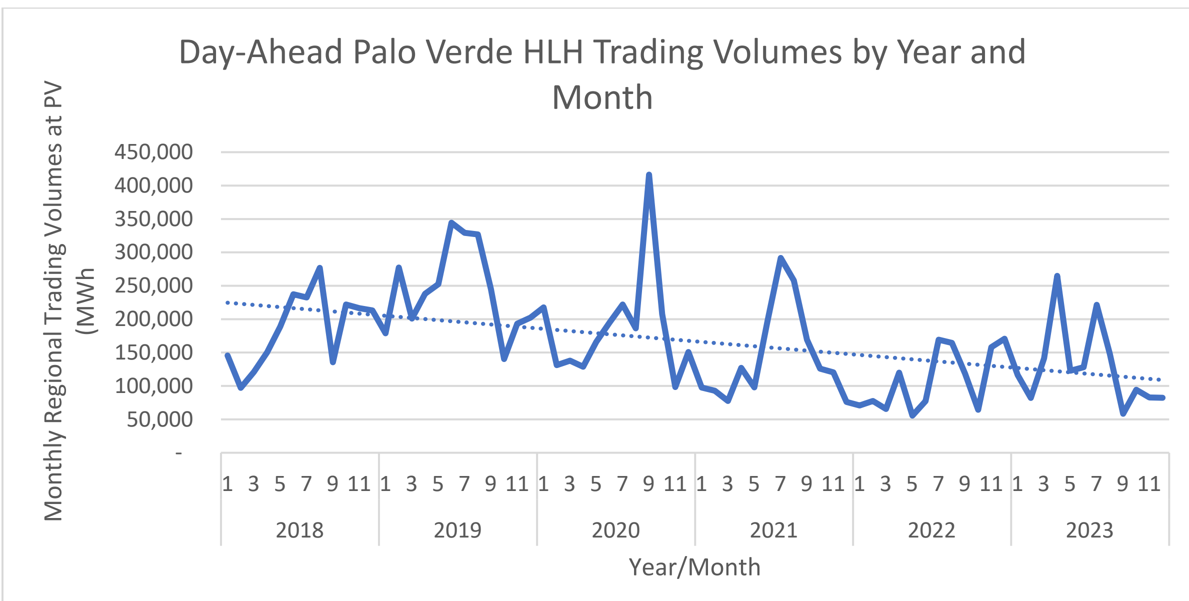


Figure PV Volumes



Q. What is the NPC impact of this modeling update?

A. Removing hedge volumes from the market sales capacity limits calculation, as well as applying limits to the

Mid-Columbia and Palo Verde sales hubs, result in a NPC increase of $84 million.

Q. Has the Company done any other tests to prove that market capacity limits are needed at the Mid-C and PV trading hubs?

A. Yes. The Company used the Aurora validation 2020 backcast model (referenced in Section VI above) as a starting point for testing. The Company then fixed (set as static and known in the model) all 2020 historical sales volumes with the exception of real-time sales volumes (i.e., from hedge volumes to day-ahead sales volumes) and then ran the model to observe the in-model (modeled) system balancing sales, which should be representative of 2020 historical real-time sales volumes, given the aforementioned fixing of all other sales volumes.

Q. Please explain this simulation of real-time sales volumes in further detail.

A. With modeled system balancing sales as a proxy for 2020 historical real-time sales there was a need to adjust the DA/RT price component to only account for historical real-time transactions. Furthermore, the DA/RT volume component was adjusted to remove the inferred daily, 25 MW increment block products that represented products from day-ahead trading. Lastly, the market capacity limits were removed in order to assess their impact.

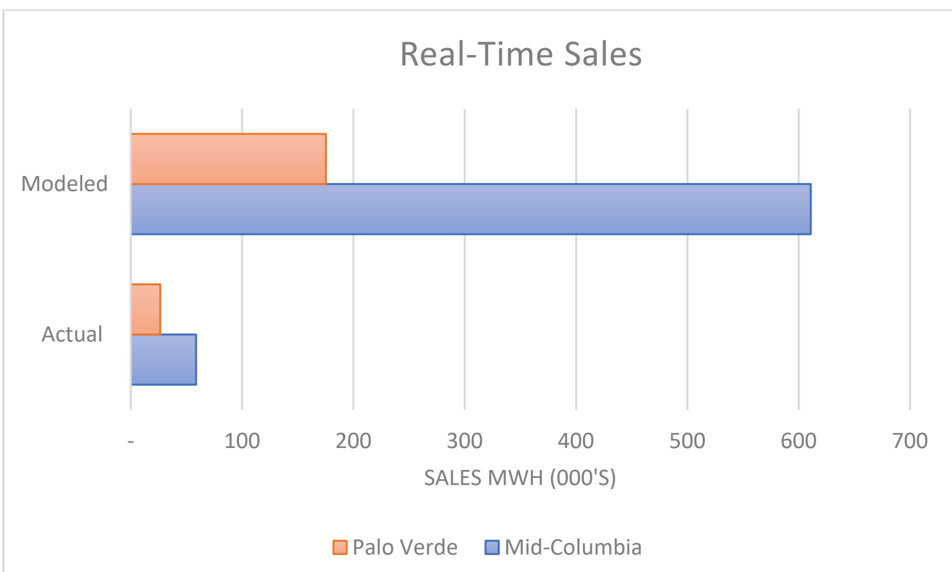
Q. How do the modeled real-time sales compare with the actual, historical real-time sales?

A. The below Table 'RT Sales' and Figure 'RT Sales' shows a comparison between modeled real-time sales and historical real-time sales at the Mid-C and PV trading hubs.

Table RT Sales

Real-Time Sales (MWh)		
	Actual	Modeled
Mid-Columbia	58,622	610,866
Palo Verde	26,432	175,257

Figure RT Sales



As can be seen from Table 'RT Sales' and Figure 'RT Sales', modeled real-time sales at the Mid-C and PV trading hubs are greater than historical real time sales by factors of 10 and 7 respectively. This demonstrates that Aurora, like GRID before it, over-optimizes system balancing sales. This over-optimization and the consequent overstatement of wholesale sales revenue, as exemplified best in the recent ECAM,[19] necessitates application of market capacity limits to all trading hubs, inclusive of Mid-C and PV.

Q. Do the increased modeled real time sales reflect increased market depth?

A. No. Please refer to Confidential Figure 'Market Caps' above. The modeled real-time sales from this test implies market depth that is contrary to the Company's recent experience.

VIII. 2023 WEATHER NORMALIZED LOAD

Q. What is the impact to NPC of adjusting the forecast to incorporate 2023 weather normalized load?

A. Moving from a 2025 load forecast to 2023 weather normalized load to set expectations for the 2025 NPC test period produces NPC of $2.382 billion on a total-Company basis and $136.7 million, or $39.34/MWh, on an Idaho-allocated basis. On a $/MWh basis this lowers NPC by 1.6 percent, relative to the NPC forecast that uses 2025 expected load.

[19] *In the* Matter of the Application of Rocky Mountain Power Requesting Approval of $62.4 Million ECAM Deferral, Case No. PAC-E-24-05,Direct Testimony of Jack Painter, p. 14.

Q. Please summarize this NPC proposal section of your direct testimony.

A. On an Idaho-allocated basis, the Company's NPC as modeled for the NPC test period in this case have increased by $14.80/MWh, or 60 percent, from the 2021 GRC forecast of $24.54/MWh to the current weather normalized GRC forecast of $39.34/MWh. This increase is driven by: 1) the NPC under-forecast in the 2021 GRC; 2) increases in purchased power and natural gas fuel expense that result from increased power and natural gas commodity prices, a reduction in generation due to the WA-GHG program, the expectation of lower hydroelectric generation, and coal supply challenges.

IX. NPC RECOVERY

Q. What is the purpose of this NPC recovery section?

A. The Company is proposing to update the sharing band of the energy cost adjustment mechanism (ECAM) because the current structure is outdated, and the continued under-forecast of NPC contributes to the significant financial risks currently faced by utilities. My testimony presents the Company's proposal to modify the ECAM sharing band for 95 percent of NPC variances to be passed through the mechanism. The remaining five percent of NPC variances would remain outside the mechanism (95/5 sharing band). In addition to the outdated sharing band of the ECAM - due to changes in the regional energy landscape - the Company's planned entry into a complete organized market - the California Independent System Operator (CAISO) Extended Day Ahead Market (EDAM) - further evidences the need for an update to the current sharing band.

Q. Please explain the current ECAM structure as it relates to the sharing band.

A. Commission Order No. 30904[20] authorized the Company to implement an ECAM, a mechanism to recover the differences between actual NPC and base NPC in rates. The difference between base and actual ECAM costs per kWh, both multiplied by the Company's actual retail load in Idaho, is the amount eligible for sharing under the ECAM. The current ECAM includes a 90/10 percent sharing band, meaning 90 percent of the NPC differential (variance) is either refunded to or paid by customers and the Company retains or absorbs the other 10 percent (90/10 sharing band).

Q. Why is the structure of the ECAM outdated?

A. Energy policies and their associated impacts to power costs, and the wider electric industry, in the West have changed significantly in the past decade, however, the

[20] *In the Matter of the Application of Rocky Mountain Power for Approval of an Energy Cost Adjustment Mechanism (ECAM).* Case No. PAC-E-08-08. Order No. 30904 (Sept. 29, 2009).

sharing band in Idaho that supports the recovery of Company NPC has not changed concurrently - and has been static since 2009. Since the turn of the century there has been a significant decrease in dispatchable generation across the Western United States and correspondingly, a significant increase in optimization and dispatch efficiencies that are and will be realized through participation in organized markets.

It is vital for ratemaking policies to move forward with the state of the industry. The increased volatility introduced to NPC, since 2009, by the significant shift to renewable resources across the Western United States remains unaddressed through reform of the ECAM and has had a material impact on the Company’s financial health. Furthermore, the volatility of both actual natural gas fuel prices and market power prices, since 2009, exhibit substantial deviation from the assumptions used to forecast NPC and from the conditions that existed in 2009 because of the aforementioned changes in resource mix across the Western United States. Additionally, the short-term volatility caused by extreme weather events that increase market and gas prices substantially impacts these NPC variances, relative to conditions in 2009 which were markedly more predictable.

Lastly, the Company's commitment to join the EDAM is a tremendous change, one that will drive NPC considerably lower than would otherwise be possible and demonstrates that the Company is managing its NPC to the best of its ability and following best practices within the industry. These changes now warrant the Company's proposal to update the sharing band.

Q. Is this an attempt by the Company to shift NPC risk from the Company to customers?

A. No. This is about appropriately situating the risk. In the past, circa 2009, when demand service relied on base load coal resources and some dispatchable natural gas resources to follow load, NPC could be more easily predicted because of long term fixed price coal contracts. Most of the NPC variances were less significant and caused by weather's impact on load, along with smaller fluctuations in markets prices. Under those circumstances, when generation across the Western Electricity Coordinating Council area ("WECC") was more predictable, it may have been appropriate for the Company to carry the current risk balance of NPC variances. However, today's regional load service focuses more on net load, or load less renewable generation. The costs associated with this type of load service are much harder to predict and also increases costs in times of market scarcity. For example, when solar under performs in a region and load increases above expectations this can reduce liquidity in the market and drive power prices extremely high for all utilities, as many buyers are looking to either replace that lost solar energy or cover the unexpected load increase. Inversely, when solar is over performing and load decreases below expectations power prices can fall, but only slightly, for all utilities, and there is less opportunity to make a margin on excess energy. Apart from making NPC much harder to predict, this asymmetry in market price responses creates a NPC under-forecast bias in the ECAM differential that leads to persistent under forecasts of NPC as discussed and illustrated in further detail below.

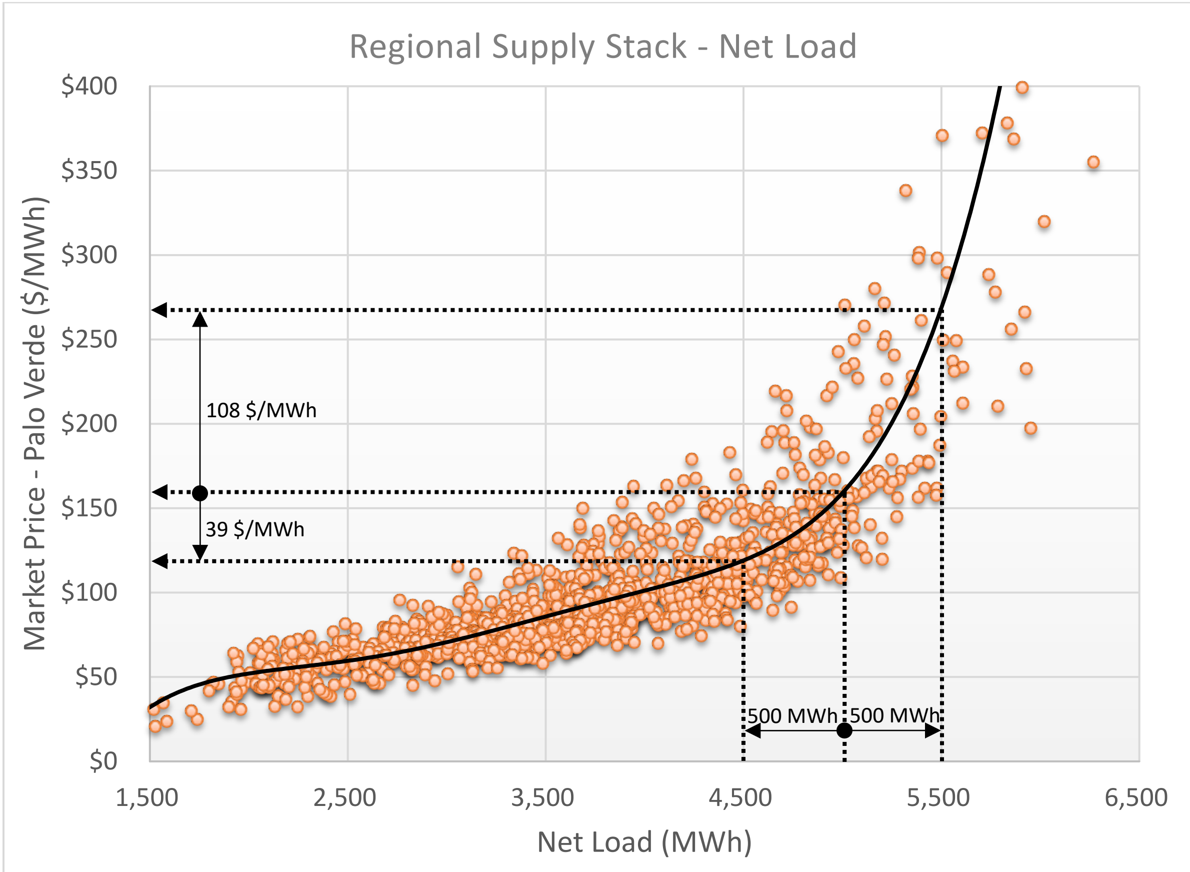
The Company has continued to reliably serve customers as market conditions and load service has changed over the years, even in times when the cost to serve load exceeds the revenue collected from customers. It is important to note that the Company does not earn a return (profit) on NPC; the Company only includes costs that have already been incurred in rates in the ECAM. As the Company continues to adapt to the state of the industry it is imperative that the regulatory structure of NPC recovery is updated to adapt concurrently. This will help support the financial health of the Company by attracting the capital necessary to continue to reliably serve customers and invest in the resources necessary to meet reliable load service.

Q. Please explain how the asymmetry in market price responses creates a NPC under-forecast bias in the ECAM differential.

A. As an illustrative example, Figure 'Regional Supply Stack' below depicts a proxy supply curve (with inelastic demand) based on actual load, wind, and solar data within the West during the summer of 2022, scaled to Rocky Mountain Power load.

In this illustrative example, because of the asymmetry of regional market price response, a 500 MWh *increase* in net load (load less wind less solar) results in a $108/MWh increase in market price whereas an identical 500 MWh *decrease* in net load results in only a $39/MWh decrease to market price.

Figure Regional Supply Stack



Because NPC move in proportion to regional market prices, and continuing with the illustrative example provided above, we observe that an unexpected increase in net load will increase NPC by an amount far greater than the decrease in NPC observed because of an identical and opposite unexpected decrease in net load.

This asymmetrical response biases the NPC forecast persistently downwards such that attempts to accurately forecast NPC will probabilistically result in actual NPC being greater than forecast NPC and consequently, persistent under-forecast of NPC which flows through the sharing band to the persistent detriment of the Company as evidenced in further detail below.

Q. Please summarize the remainder of this NPC Recovery section.

A. Below, I provide:

- An overview of the shift in resource mix across the Western United States since the sharing band was established in 2009 and how that impacts the volatility of power costs;
- Next, I discuss the EDAM at a high level and how NPC are handled by utilities in the Company’s other jurisdictions;
- Additionally, I discuss how the current structure of the ECAM has impacted the Company’s finances; and
- Finally, I describe how the NPC forecast set in regulatory proceedings have no bearing on the Company’s incurred NPC, and I describe how NPC variances are disconnected from the reality of power system operations.

Q. Are there any other Company witnesses providing testimony on this NPC Recovery topic?

A. Yes, Company witness John Tsoukalis from The Brattle Group is providing testimony on the mechanics of the EDAM, how it provides efficient outcomes and customer benefits, and how these results impact the ECAM. He additionally provides information on the current state of the industry with regards to the structure of other NPC true-up mechanisms, like the ECAM.

A. <u>Region-Wide change in Generation Resources</u>

Q. How has dispatchable energy and demand changed within the WECC since the implementation of the current ECAM sharing band?

A. From 2009 to 2022, dependable, dispatchable capacity, which includes coal and natural gas, has been on a declining trend and has decreased significantly overall. As shown in Table 'Summer Megawatts' below, total summer dispatchable capacity in the states compromising the WECC has decreased from approximately 122,000 megawatts ("MW") to 110,000 MW, or 10 percent. On the other side of the equation, summer peak demand is on an upward trajectory. As shown in Table 'Summer Megawatts' below, peak demand has steadily increased between 2009 and 2022 from approximately 134,000 MW to 160,000 MW, or 19 percent.

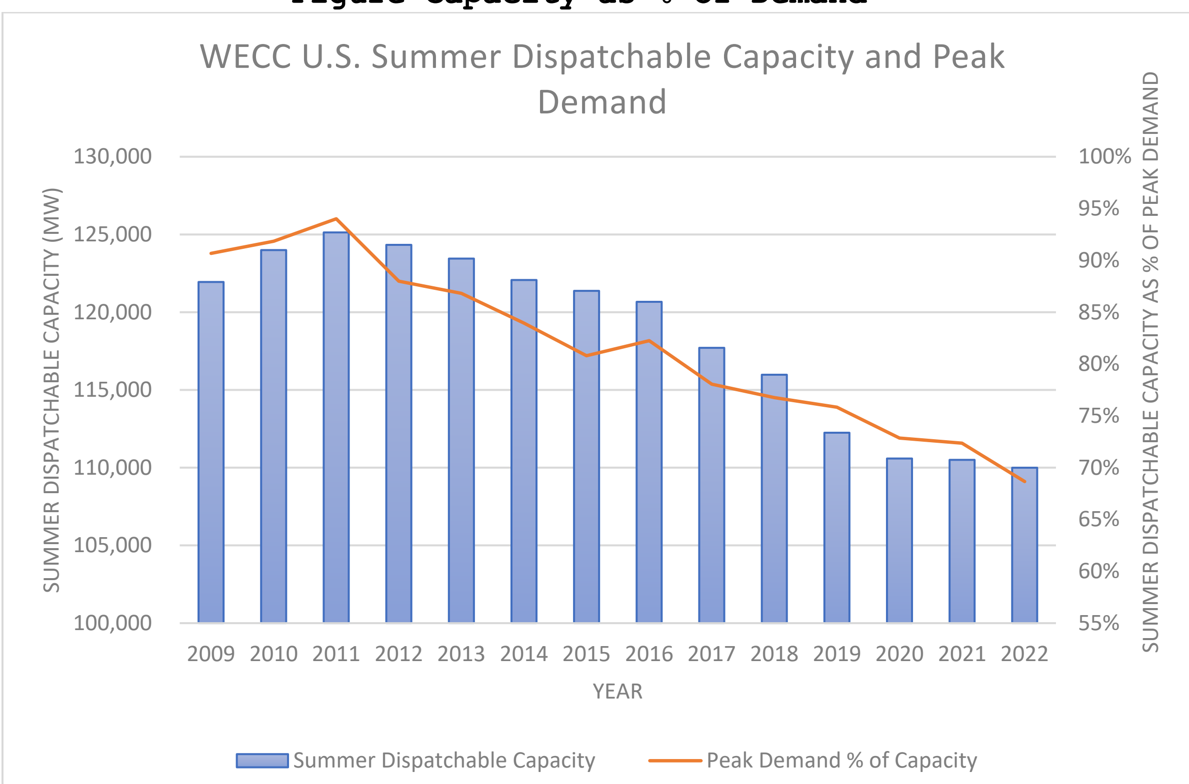
Table Summer Megawatts

Year	Summer Dispatchable Capacity (MW)	Summer Peak Load (MW)
2009	121,945	134,477
2010	123,997	135,000
2011	125,133	133,100
2012	124,332	141,300
2013	123,450	142,200
2014	122,073	145,400
2015	121,374	150,200
2016	120,669	146,700
2017	117,709	150,800
2018	115,979	151,100
2019	112,249	148,000
2020	110,590	151,800
2021	110,504	152,700
2022	109,998	160,200

Q. Why is this shift in dispatchable capacity and demand within the WECC important to the ECAM?

A. The ECAM operates as a mechanism for the Company to refund or collect from customers a measure of normal power cost variances incurred under the intent to incentivize prudent decisions. Because of the significant shift of both dispatchable capacity and demand, power cost variances today are no longer normal, relative to the norms of 2009 when the current ECAM sharing band was established — and therefore, prudently incurred costs are not being recovered. Additionally, this significant shift in dispatchable capacity and demand within the WECC has not only impacted the Company, but all utilities in the West, compounding the problem further by impacting utilities that the Company transacts with and competes with for market purchases. Figure 'Capacity as % of Demand' below visually illustrates the shift in the states comprising the WECC where dispatchable capacity has steadily decreased in absolute terms (MW) and decreased as a percentage of annual peak demand. Shortly after the current ECAM sharing band was established in 2009, summer dispatchable capacity in 2011 was rated at 94 percent of summer peak demand in 2011. In 2022, dispatchable capacity was much lower, rated at 69 percent of peak demand.

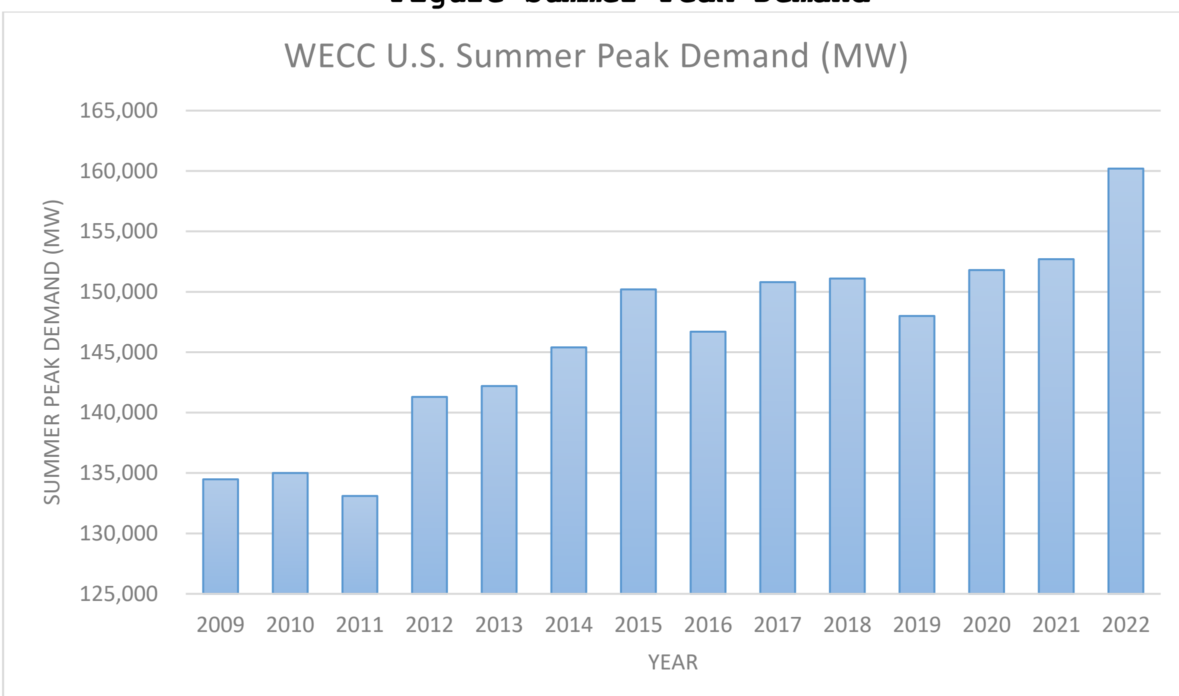
Figure Capacity as % of Demand



Q. Has the demand during summer peak hours changed?

A. Yes, as referenced above. Between 2009 and 2022, the greatest shift in demand has been during summer peak hours (June through September). Figure 'Summer Peak Demand' below visually depicts this increasing trend in peak demand since the inception of the current ECAM sharing band in 2009. In 2009, demand during summer peak hours was approximately 134,000 MW and increased to 160,000 MW in 2022, or a 19 percent increase.

Figure Summer Peak Demand



Q. How has the increased demand during summer peak hours impacted the ECAM?

A. In both 2021 and 2022, the Company experienced heightened NPC due to extreme weather events during the summer. The combination of increased demand, particularly during the summer, and less dispatchable capacity results in market scarcity and high prices and the impact to NPC is intensified. June and July of 2021 alone accounted for 80 percent of the 2021 ECAM NPC differential, while July, August and September of 2022 accounted for almost 50 percent of the total 2022 ECAM differential. Both examples of these substantial NPC variances are outside of the normal operating business risk of the Company (wherein normal is based on conditions in 2009).

Q. Does the trend of decreasing dispatchable capacity and increasing demand within the WECC necessitate and warrant changes to the ECAM?

A. Yes. The risks between the Company providing reliable energy and the commodity-driven costs to serve its variable customer demand are not the same as when the ECAM sharing band was established in 2009; the industry is now substantively different. With the loss of dispatchable capacity and with increased demand across the West and the associated consequential changes in the market, the risk balance for power costs has been fundamentally altered. The Company is proposing this sharing band change as consistent with the fact that power cost variances have increased significantly and can no longer be considered normal relative to 2009 when the current sharing band was implemented. Now, with this increased variance and associated volatility, a sharing percentage of five (95/5 sharing band) is now appropriate.

B. <u>The EDAM - Utilities in Organized Markets</u>

Q. The Company has announced its intention to join EDAM. What is the EDAM?

A. The EDAM is an initiative by the CAISO to extend participation of a developed and organized day-ahead, hour-ahead and intra-hour market to the region. The EDAM will provide economically optimal and least-cost resource schedules, commitment instructions, and other core functions integral to organized markets across the footprints of independent system operators ("ISO") and regional transmission organizations ("RTO"). Operational control of resources will remain with the Company, but the EDAM will allow for the co-optimization of the Company's resources along with the resources of other EDAM participants for substantially lowered NPC, than otherwise achievable by the Company in isolation. Company witness Tsoukalis provides much greater detail on the EDAM and how system dispatch and economic efficiencies will change.

Q. Does participation in the EDAM create substantially lowered NPC with minimal room for further decrease in service of the Company's customers?

A. Certainly. As a result of the decision to participate in the EDAM, the economic operations of the Company's system on a day-ahead, hour-ahead and intra-hour basis will be optimized by an ISO whose mandate is to leverage state of the art optimization software to minimize power costs for all market participants. As discussed in the testimony of Company witness Tsoukalis, the EDAM will provide lower NPC than what the Company could achieve on its own.

Q. Does joining the EDAM impact the Company's ability to accurately forecast NPC?

A. Yes. As explained by Company witness Tsoukalis, NPC in the EDAM is driven by conditions across the wider EDAM footprint which extends into other utilities' systems. Data on these conditions within other utilities' systems will be unavailable to the Company due to their confidential nature and therefore it will be extremely difficult for any individual EDAM participant to accurately forecast the NPC outcomes of the market.

Q. What impact does an inaccurate forecast have on the ECAM?

A. An inaccurate forecast can lead to significant NPC variances (as evidenced in 2021, 2022, 2023 and 2024 year-to-date) in the ECAM that will lead to costs prudently incurred by the Company, to reliably serve customer load, to either: (1) not be collected; or (2) when actual costs are below forecast, to be retained by the Company and not properly returned to customers.

Q. How are utilities in organized markets treated in terms of NPC variances in their power cost recovery mechanisms?

A. While this is covered in greater detail in the testimony of Company witness Tsoukalis, it is important to note that across the 35 states he reviewed that have vertically integrated utilities, 26 have full passthrough of NPC. Of the 20 remaining that participate wholly or partially in an ISO/RTO type organized market like the EDAM, only Missouri, Montana and Vermont do not have complete pass through of net power costs.[21]

Q. How do the power cost recovery mechanisms in the Company's other jurisdictions operate?

A. The Company operates in six different state jurisdictions, each with a power cost recovery mechanism. Utah and California do not have a sharing band, which represent almost half of the Company's total NPC. Wyoming has a sharing band. Oregon and Washington

[21] Wisconsin is an exception among the 26 full passthrough states in that it employs a 2% deadband to modify the cost deviations from forecasts that are eligible for a full passthrough to customers.

have both dead bands and sharing bands. The Company has or will be pursuing similar changes as proposed here, in Oregon, Washington and Wyoming.

Q. Is there anything unique about the Company's jurisdictions?

A. Yes. Only four[22] states that currently participate in EDAM like markets do not have a pass-through mechanism that result in full recovery of prudently incurred costs. With the implementation of the EDAM there would be eight, and four of those eight would be states the Company serves, so a comparison to states served by the Company is not representative of the ratemaking approach to recovery of NPC across the utility industry. The four states within the Company's service area are therefore outliers compared to the rest of the nation.

C. <u>Current ECAM Structure</u>

Q. Is the current ECAM sharing band functioning in an equitable fashion?

A. Not at all. Based upon the current ECAM design, it would be expected that over and under-forecasts of NPC along with the attendant returns and collections would balance each other out over the long term. Since the inception of the ECAM in 2009, fourteen out of the fifteen years

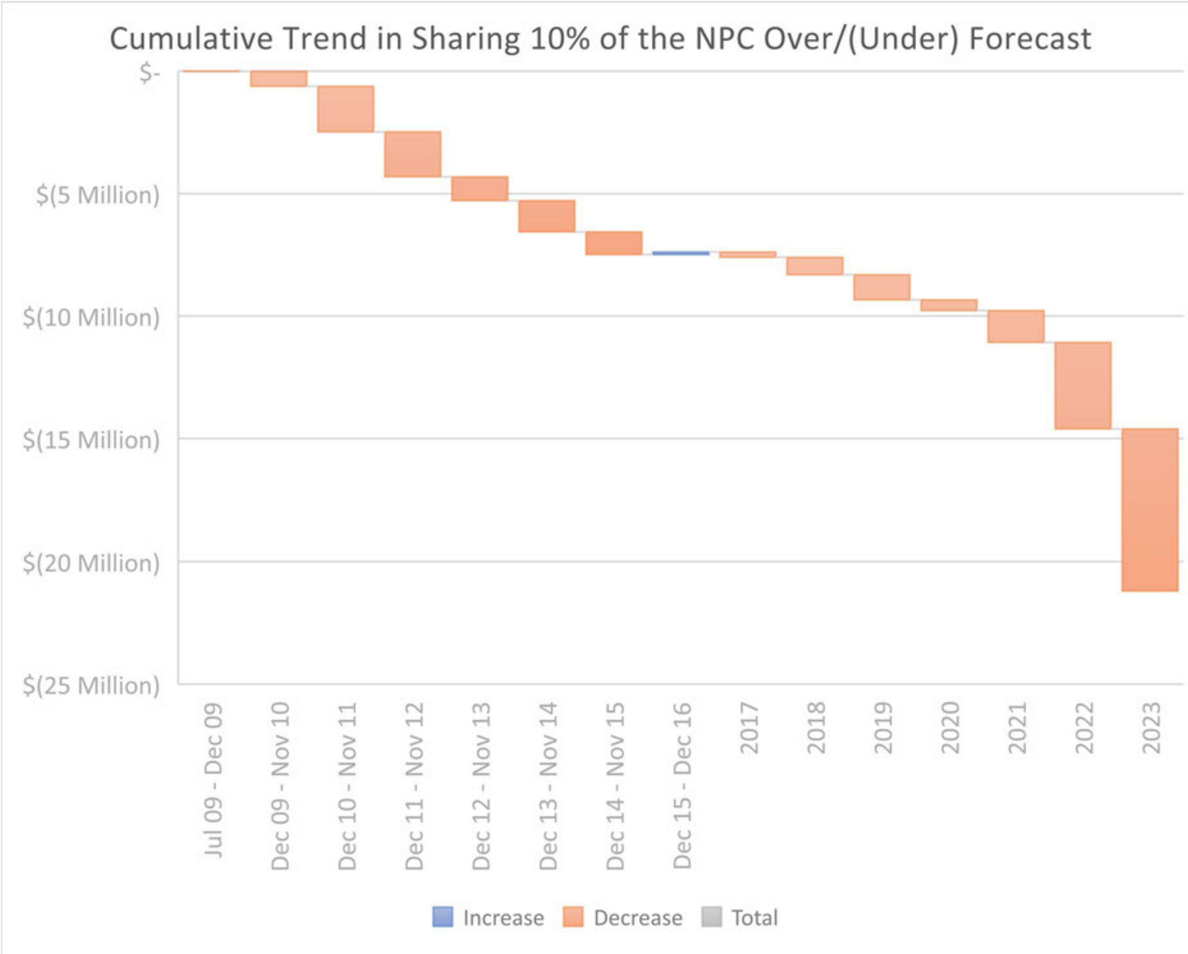
[22] Wisconsin is added here to the prior three of Missouri, Montana and Vermont.

have resulted in NPC under-forecasts and associated under-collection of prudently incurred NPC due to the current sharing band. However, it’s expected that there should be a more balanced distribution of under-forecast *and* over-forecast of NPC. During this time frame, the Company has seen a cumulative Idaho-allocated NPC under-forecast of $212 million, which translates to an approximate $21.2 million under-collection after application of ten percent sharing. Table ‘Sharing Band NPC Impact’ and Figure ‘Sharing Band NPC Impact ’ below show the annual details of that under-forecast, and vividly illustrates the opposite of long-term balance between ratepayers and the Company.

Table Sharing Band NPC Impact

Year	NPC 10% Sharing - Over/(Under) Forecast
Jul 09 - Dec 09	($12,150)
Dec 09 - Nov 10	($607,352)
Dec 10 - Nov 11	($1,856,902)
Dec 11 - Nov 12	($1,835,877)
Dec 12 - Nov 13	($979,139)
Dec 13 - Nov 14	($1,273,551)
Dec 14 - Nov 15	($926,976)
Dec 15 - Dec 16	$105,107
2017	($211,347)
2018	($715,259)
2019	($1,027,552)
2020	($433,086)
2021	($1,304,085)
2022	($3,532,283)
2023	($6,587,473)
Total	**($21,197,925)**

Figure Sharing Band NPC Impact



Q. Does the current 90/10 ECAM sharing band act as an appropriate incentive for the Company to manage costs effectively?

A. No. As provided in more detail in the testimony of Company witness Tsoukalis, the Company has announced its intention to join the EDAM, which will create efficiencies that reduce NPC.[23] Once the EDAM is

[23] *PacifiCorp to build on success of real-time energy market innovation as first to sign on to new Western day-ahead market*, PACIFICORP (Dec. 8, 2022), https://www.pacificorp.com/about/newsroom/news-releases/EDAM-innovative-efforts.html.

operational in 2026, the sharing band at 90/10 is neither effective or necessary to incentivize the Company to manage its NPC because the EDAM will more efficiently optimize the dispatch of resources to produce the least cost outcome subject to constraints on the power system, in a manner which goes above and beyond the Company's capabilities in isolation. Lastly, the Company operates its system on a least-cost basis on behalf of all its customers in all six of its jurisdictions. As stated above, two of these jurisdictions contain a full passthrough of NPC and represent almost half of the Company's total NPC and associated variance. Given that the Company's participation in the EDAM will lower its NPC to the lowest level attainable and given how it operates its system across all six jurisdictions, the current 90/10 sharing band is neither effective or necessary to incentivize the Company to manage or reduce its NPC.

Q. How does this continued under-recovery of prudently incurred NPC in Idaho impact the financial health of the Company?

A. Recovery of costs that are incurred to serve customers are necessary to ensure that the Company has the liquidity to fund its operations and to safely and reliability serve its customers. To the extent that the

Company is continuously under recovering actual costs that were prudently incurred to serve customers, it places more pressure on the Company's liquidity and cash reserves and may result in increased short-term and long-term borrowing. This larger debt increases the Company's leverage, which in turn increases the cost of interest and places further pressure on the Company's credit metrics and limits the Company's ability to absorb increased prices for electricity and fuel to serve its customers. To the extent that the Company has an increased requirement to borrow money and higher borrowing costs, these costs not only harm the health of the utility but would be passed on to customers and can ultimately result in a downgrade of its credit rating. Company witness Nikki L. Kobliha discusses these topics in more detail.

D. <u>The NPC Forecast</u>

Q. Does the Company operate the system with these regulatory NPC forecasts in mind?

A. No, and it would be imprudent to do so. The Company's energy supply management ("ESM") group, which optimizes actual NPC in actual operations, does not operate with the NPC forecast as a target. Company NPC forecasts created during general rate cases, or other filings, are only used to set NPC for ratemaking purposes, they are not used or referred to in actual Company operations. ESM is constantly - on a daily and more granular basis - updating its forward prices, renewable resource forecast, load forecast, etc. to manage NPC for a least-cost outcome on behalf of all of its customers.

Q. Can the Company improve the forecasting of model inputs to capture all prudently incurred costs in the forecast?

A. No, for several reasons. First, it is very difficult to accurately forecast key NPC variables such as intermittent renewable resources, extreme weather events, and volatile market conditions for market power prices and natural gas prices, especially when the forecast is required to be normalized. Even minor variables can have a significant impact on the Company's large and complex power supply system. Second, as mentioned above in further detail, the confidential nature of other utilities' operational details will make it extremely difficult for any individual EDAM participant to accurately forecast the NPC outcomes of the market, once the EDAM is implemented.

X. CONCLUSION

Q. Please summarize your recommendation to the Commission.

A. I recommend that the Commission: (1) adopt the proposed base NPC for the NPC test period of $136.7 million, or $39.34/MWh; and (2) approve a better solution for both customers and the Company through modifying the sharing band from a 90/10 percent Company/customer sharing structure to a 95/5 percent Company/customer sharing structure, which would ensure that the overwhelming majority of prudently incurred NPC are appropriately refunded to or collected from customers.

Q. Does this conclude your direct testimony?

A. Yes.

Case No. PAC-E-24-04
Exhibit No. 23
Witness: Ramon J. Mitchell

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Ramon J. Mitchell

2025 NPC Report

May 2024

Exhibit 23

	Total	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25
								$					
Special Sales For Resale													
Long Term Firm Sales													
Black Hills	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Hurricane Sale	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Leaning Juniper Revenue	$ 292,041	$ 21,466	$ 19,348	$ 21,989	$ 14,723	$ 14,161	$ 13,437	$ 41,893	$ 46,324	$ 34,305	$ 23,624	$ 18,766	$ 22,007
PSCo_Sale	$ 13,182,454	$ 878,915	$ 812,880	$ 911,908	$ 663,180	$ 676,640	$ 868,951	$ 2,190,767	$ 2,214,464	$ 2,118,417	$ 687,033	$ 444,608	$ 714,692
Total Long Term Firm Sales	$ 13,474,495	$ 900,381	$ 832,228	$ 933,897	$ 677,903	$ 690,801	$ 882,388	$ 2,232,660	$ 2,260,788	$ 2,152,721	$ 710,656	$ 463,374	$ 736,699
Short Term Firm Sales													
Borah	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
COB	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Colorado	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Four Corners	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Idaho	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Mead	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Mid Columbia	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Mona	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NOB	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Palo Verde	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
SP15	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Utah	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Washington	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
West Main	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wyoming	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Short Term Firm Sales	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
System Balancing Sales													
COB	$ 53,708,780	$ 3,900,189	$ 3,229,620	$ 1,593,738	$ 1,701,032	$ 1,674,744	$ 2,126,186	$ 6,495,281	$ 8,425,507	$ 17,472,693	$ 2,454,677	$ 2,169,901	$ 2,465,213
Four Corners	$ 42,620,952	$ 5,026,368	$ 2,679,543	$ 2,378,502	$ 1,872,379	$ 1,093,437	$ 1,466,982	$ 4,330,703	$ 4,387,393	$ 9,640,334	$ 2,304,458	$ 3,371,222	$ 4,069,633
Mead	$ 476,137	$ 1,569,682	$ 5,101	$ (574,020)	$ 7,257	$ 13,725	$ 14,174	$ 7,692	$ 287,660	$ 4,285	$ (922,317)	$ 6,192	$ 56,705
Mid Columbia	$ 107,504,415	$ 21,519,395	$ 9,234,129	$ 5,265,866	$ 4,943,184	$ 1,860,054	$ 3,481,987	$ 10,542,246	$ 11,149,673	$ 7,410,264	$ 9,045,541	$ 8,460,382	$ 14,591,694
Mona	$ 16,077,006	$ 1,745,241	$ 1,600,242	$ 607,698	$ 566,574	$ 489,431	$ 696,902	$ 2,135,089	$ 2,530,603	$ 2,435,828	$ 732,765	$ 895,538	$ 1,641,096
NOB	$ 24,419,632	$ 3,002,149	$ 1,949,205	$ 1,413,816	$ 595,041	$ 532,798	$ 915,989	$ 4,245,440	$ 3,718,665	$ 1,473,505	$ 1,936,754	$ 1,952,254	$ 2,684,016
Palo Verde	$ 3,661,376	$ 295,147	$ 218,322	$ 50,769	$ 162,353	$ 147,882	$ 275,894	$ 567,030	$ 252,519	$ 767,216	$ 168,134	$ 273,889	$ 482,220
Trapped Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total System Balancing Sales	$ 248,468,299	$ 37,058,171	$ 18,916,161	$ 10,736,369	$ 9,847,820	$ 5,812,070	$ 8,978,113	$ 28,323,482	$ 30,752,020	$ 39,204,125	$ 15,720,013	$ 17,129,378	$ 25,990,575
Total Special Sales For Resale	$ 261,942,794	$ 37,958,552	$ 19,748,389	$ 11,670,266	$ 10,525,723	$ 6,502,870	$ 9,860,501	$ 30,556,142	$ 33,012,808	$ 41,356,846	$ 16,430,669	$ 17,592,752	$ 26,727,274

Purchased Power & Net Interchange

Long Term Firm Purchases

Appaloosa 1A Solar	$ 10,292,182	$ 559,723	$ 593,465	$ 906,325	$ 978,713	$ 1,146,027	$ 1,210,510	$ 1,060,453	$ 1,033,174	$ 974,493	$ 775,447	$ 576,254	$ 477,599
Appaloosa 1B Solar	$ 6,861,455	$ 373,148	$ 395,643	$ 604,217	$ 652,475	$ 764,018	$ 807,006	$ 706,969	$ 688,783	$ 649,662	$ 516,964	$ 384,170	$ 318,399
Castle Solar UoU	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Castle Solar IHC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Cedar Springs Wind	$ 11,723,272	$ 1,348,848	$ 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	$ 8,908,094	$ 1,025,293	$ 832,068	$ 784,236	$ 772,111	$ 631,271	$ 565,347	$ 564,366	$ 445,199	$ 628,829	$ 828,668	$ 811,823	$ 1,018,881
Cedar Springs Wind IV	$ 35,181,067	$ 4,332,908	$ 3,096,960	$ 2,854,190	$ 2,509,530	$ 2,311,613	$ 2,072,340	$ 2,005,125	$ 2,086,972	$ 2,345,721	$ 3,189,306	$ 3,831,121	$ 4,545,280
Combine Hills Wind	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Cove Mountain Solar	$ 3,802,638	$ 182,379	$ 191,610	$ 333,997	$ 363,597	$ 418,499	$ 450,080	$ 436,591	$ 413,105	$ 354,252	$ 285,173	$ 204,900	$ 168,457
Cove Mountain Solar II	$ 9,387,257	$ 450,472	$ 473,272	$ 824,965	$ 898,077	$ 1,033,683	$ 1,111,688	$ 1,078,370	$ 1,020,362	$ 874,994	$ 704,370	$ 503,256	$ 413,748
Deseret Purchase	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Eagle Mountain - UAMPS/UMPA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Elektron Solar 20yr	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Elektron Solar 25yr	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Gemstate	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Graphite Solar	$ 6,197,453	$ 310,012	$ 351,184	$ 554,615	$ 608,658	$ 682,657	$ 700,495	$ 683,227	$ 639,131	$ 572,798	$ 477,596	$ 353,010	$ 264,071
Hermiston Purchase	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Horseshoe Solar	$ 6,072,682	$ 266,686	$ 331,075	$ 499,533	$ 565,742	$ 674,491	$ 746,804	$ 734,022	$ 695,525	$ 578,539	$ 464,831	$ 287,300	$ 228,132
Hunter Solar	$ 6,980,641	$ 367,456	$ 416,574	$ 634,629	$ 662,343	$ 755,267	$ 781,559	$ 743,007	$ 698,452	$ 651,256	$ 555,766	$ 394,179	$ 320,154
Hurricane Purchase	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
MagCorp Buythrough	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
MagCorp Reserves	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Milican Solar	$ 2,973,753	$ 98,000	$ 149,553	$ 229,015	$ 288,259	$ 342,133	$ 372,405	$ 419,382	$ 370,578	$ 298,239	$ 195,281	$ 125,077	$ 85,830
Milford Solar	$ 6,870,872	$ 347,985	$ 400,729	$ 591,100	$ 657,488	$ 772,977	$ 814,984	$ 725,777	$ 698,695	$ 651,754	$ 525,630	$ 382,415	$ 301,336
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	$ 20,600,000	$ 1,716,667	$ 1,716,667	$ 1,716,667	$ 1,716,667	$ 1,716,667	$ 1,716,667	$ 1,716,667	$ 1,716,667	$ 1,716,667	$ 1,716,667	$ 1,716,667	$ 1,716,667
Pavant III Solar	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
PGE Cove	$ 164,065	$ 13,672	$ 13,672	$ 13,672	$ 13,672	$ 13,672	$ 13,672	$ 13,672	$ 13,672	$ 13,672	$ 13,672	$ 13,672	$ 13,672
Prineville Solar	$ 1,981,228	$ 67,243	$ 102,616	$ 152,164	$ 191,528	$ 227,324	$ 247,437	$ 278,650	$ 246,223	$ 198,159	$ 129,751	$ 83,105	$ 57,028
Rocket Solar	$ 6,473,420	$ 294,299	$ 354,922	$ 535,304	$ 606,639	$ 708,931	$ 796,698	$ 816,692	$ 738,987	$ 621,305	$ 472,470	$ 288,647	$ 238,526
Sigurd Solar	$ 5,858,273	$ 306,467	$ 342,172	$ 504,657	$ 550,996	$ 633,287	$ 696,030	$ 647,114	$ 593,204	$ 553,821	$ 449,403	$ 315,824	$ 265,298
Small Purchases eas	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Small Purchases wes	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Soda Lake Geotherma	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Three Buttes Wind	$ 20,425,527	$ 2,791,462	$ 1,807,438	$ 2,137,611	$ 1,500,892	$ 1,396,261	$ 1,192,997	$ 808,784	$ 951,391	$ 1,185,538	$ 1,707,698	$ 2,352,258	$ 2,593,195
Top of the World Wind	$ 36,016,304	$ 3,058,919	$ 2,762,895	$ 3,058,919	$ 2,960,244	$ 3,058,919	$ 2,960,244	$ 3,058,919	$ 3,058,919	$ 2,960,244	$ 3,058,919	$ 2,960,244	$ 3,058,919
Wolverine Creek Wind	$ 10,564,645	$ 793,982	$ 927,710	$ 1,182,235	$ 1,015,380	$ 799,504	$ 863,936	$ 698,003	$ 667,573	$ 785,474	$ 849,044	$ 1,002,522	$ 979,281
Faraday B Sola	$ 7,312,704	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 176,512	$ 3,317,436	$ 2,124,238	$ 1,694,518
Hornshadow I Sola	$ 4,732,093	$ -	$ -	$ -	$ -	$ -	$ 36,191	$ 1,067,525	$ 980,187	$ 893,225	$ 771,362	$ 535,520	$ 448,084
Hornshadow II Sola	$ 9,470,203	$ -	$ -	$ -	$ -	$ -	$ 72,382	$ 2,135,050	$ 1,960,374	$ 1,789,170	$ 1,542,724	$ 1,074,337	$ 896,167
Green River Energy Cente	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Anticline Wind	$ 17,940,049	$ 2,163,887	$ 1,666,478	$ 1,559,965	$ 1,313,666	$ 1,135,050	$ 1,085,959	$ 1,032,757	$ 1,092,044	$ 1,208,912	$ 1,590,032	$ 1,906,748	$ 2,184,552
Boswell Springs Wind	$ 33,509,492	$ 3,612,555	$ 3,273,801	$ 3,165,874	$ 2,914,066	$ 2,654,216	$ 2,240,134	$ 1,878,535	$ 1,811,646	$ 2,082,505	$ 2,949,429	$ 3,157,338	$ 3,769,394
Two River Wind LLC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Cedar Creek	$ 20,742,033	$ 1,898,940	$ 1,671,841	$ 2,588,474	$ 1,733,785	$ 1,837,879	$ 1,203,586	$ 1,378,214	$ 1,091,693	$ 1,311,073	$ 2,183,871	$ 2,128,399	$ 1,714,280
OR Schedule 126 CSP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
UT Schedule Adjustment	$ (41,924,762)	$ (1,640,749)	$ (1,887,207)	$ (3,311,367)	$ (3,698,587)	$ (4,396,217)	$ (3,933,075)	$ (3,636,688)	$ (3,372,916)	$ (3,008,179)	$ (6,117,686)	$ (3,900,688)	$ (3,021,402)
Long Term Firm Purchases Total	$ 276,246,441	$ 25,334,404	$ 21,674,490	$ 23,747,390	$ 21,386,125	$ 20,743,103	$ 20,164,108	$ 22,388,115	$ 21,519,780	$ 22,490,285	$ 24,838,508	$ 25,274,825	$ 26,685,308

Qualifying Facilities													
QF California	$ 1,314,277	$ 66,937	$ 226,676	$ 239,350	$ 143,699	$ 109,361	$ 127,769	$ 100,913	$ 959	$ 902	$ 942	$ 120,265	$ 176,503
QF Idaho	$ 7,638,182	$ 661,629	$ 512,036	$ 706,334	$ 678,303	$ 642,185	$ 724,111	$ 637,195	$ 583,647	$ 563,518	$ 631,714	$ 634,197	$ 663,313
QF Oregon	$ 38,426,688	$ 2,005,238	$ 2,478,115	$ 3,038,383	$ 3,518,395	$ 4,370,533	$ 4,575,096	$ 4,746,825	$ 4,245,142	$ 3,466,096	$ 3,001,624	$ 1,723,539	$ 1,257,702
QF Utah	$ 5,159,202	$ 359,100	$ 351,969	$ 437,654	$ 458,387	$ 588,172	$ 549,751	$ 505,280	$ 461,769	$ 457,985	$ 440,105	$ 319,931	$ 229,099
QF Washington	$ 418,404	$ -	$ 0	$ -	$ 17,826	$ 9,844	$ 66,132	$ 125,752	$ 127,291	$ 54,687	$ 16,872	$ -	$ -
QF Wyoming	$ 37,864	$ 3,348	$ 3,684	$ 3,409	$ 5,781	$ 2,351	$ 966	$ 1,525	$ 1,513	$ 2,162	$ 7,404	$ 1,169	$ 4,554
Biomass One QF	$ 18,106,765	$ 1,488,124	$ 1,313,070	$ 1,441,737	$ 1,306,502	$ 1,726,920	$ 1,715,281	$ 1,600,718	$ 1,658,504	$ 1,630,706	$ 1,669,668	$ 1,665,167	$ 890,365
Chopin Wind QF	$ 2,012,997	$ 187,801	$ 192,540	$ 164,798	$ 187,529	$ 168,121	$ 173,396	$ 159,633	$ 144,262	$ 129,099	$ 174,434	$ 170,787	$ 160,596
Chopin Schumann Wind QF	$ 350,933	$ 28,121	$ 26,579	$ 34,448	$ 32,592	$ 29,609	$ 31,270	$ 26,938	$ 26,579	$ 21,389	$ 25,602	$ 31,845	$ 35,960
DCFP QF	$ 52,863	$ 7,735	$ 3,713	$ 3,050	$ 2,390	$ 3,336	$ 4,013	$ 28,625	$ -	$ -	$ -	$ -	$ -
Enterprise Solar I QF	$ 11,486,229	$ 601,040	$ 728,906	$ 935,653	$ 986,969	$ 1,211,715	$ 1,100,258	$ 1,543,255	$ 1,364,298	$ 1,106,789	$ 767,407	$ 611,989	$ 527,951
Escalante Solar I QF	$ 10,960,429	$ 552,577	$ 660,609	$ 855,376	$ 960,493	$ 1,170,000	$ 1,236,834	$ 1,421,370	$ 1,268,856	$ 1,025,355	$ 750,339	$ 565,164	$ 493,457
Escalante Solar II QF	$ 10,545,170	$ 517,171	$ 620,956	$ 805,851	$ 910,651	$ 1,106,171	$ 1,213,693	$ 1,357,664	$ 1,249,999	$ 977,757	$ 780,015	$ 544,904	$ 460,340
Escalante Solar III QF	$ 10,231,225	$ 503,513	$ 606,095	$ 782,229	$ 889,843	$ 1,081,064	$ 1,183,314	$ 1,302,622	$ 1,245,053	$ 961,999	$ 731,353	$ 522,293	$ 421,846
ExxonMobil QF	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Five Pine Wind QF	$ 9,647,327	$ 605,136	$ 986,312	$ 889,628	$ 849,689	$ 549,273	$ 603,818	$ 734,917	$ 696,663	$ 874,751	$ 831,130	$ 1,006,632	$ 1,019,378
Granite Mountain East Solar QF	$ 10,828,730	$ 582,027	$ 681,713	$ 848,136	$ 953,738	$ 1,100,787	$ 1,236,204	$ 1,383,394	$ 1,221,769	$ 966,531	$ 795,084	$ 567,026	$ 492,320
Granite Mountain West Solar QF	$ 6,029,042	$ 363,898	$ 417,364	$ 507,854	$ 102,582	$ 705,510	$ 616,766	$ 880,427	$ 733,386	$ 599,306	$ 459,431	$ 334,626	$ 307,891
Iron Springs Solar QF	$ 10,623,665	$ 580,491	$ 666,604	$ 846,422	$ 944,453	$ 1,116,100	$ 1,116,806	$ 1,375,972	$ 1,234,830	$ 973,676	$ 744,071	$ 536,591	$ 487,650
Latigo Wind Park QF	$ 9,187,773	$ 1,001,258	$ 894,241	$ 1,052,637	$ 824,543	$ 855,024	$ 614,626	$ 679,468	$ 516,350	$ 588,070	$ 720,120	$ 663,502	$ 777,933
Mountain Wind 1 QF	$ 8,786,370	$ 1,383,421	$ 1,044,417	$ 858,588	$ 659,082	$ 485,398	$ 495,144	$ 408,433	$ 434,347	$ 455,797	$ 666,342	$ 882,811	$ 1,012,591
Mountain Wind 2 QF	$ 13,538,729	$ 2,000,904	$ 1,551,179	$ 1,323,297	$ 1,006,259	$ 749,034	$ 866,797	$ 752,901	$ 717,302	$ 750,963	$ 968,898	$ 1,361,006	$ 1,490,189
North Point Wind QF	$ 20,612,280	$ 1,213,451	$ 2,029,595	$ 1,892,017	$ 1,835,127	$ 1,159,894	$ 1,304,004	$ 1,629,801	$ 1,647,255	$ 1,985,981	$ 1,854,710	$ 2,042,749	$ 2,017,696
Oregon Wind Farm QF	$ 12,143,464	$ 998,097	$ 1,099,728	$ 836,188	$ 828,470	$ 576,410	$ 491,712	$ 1,462,155	$ 1,714,433	$ 1,207,746	$ 727,054	$ 838,154	$ 1,363,319
Orchard Wind 1 QF	$ 2,292,221	$ 171,662	$ 118,895	$ 219,195	$ 251,479	$ 235,568	$ 254,560	$ 223,460	$ 225,588	$ 164,749	$ 147,452	$ 133,685	$ 145,928
Orchard Wind 2 QF	$ 2,292,261	$ 171,662	$ 118,895	$ 219,195	$ 251,601	$ 235,743	$ 254,302	$ 223,460	$ 225,588	$ 164,749	$ 147,452	$ 133,685	$ 145,928
Orchard Wind 3 QF	$ 2,292,583	$ 171,662	$ 118,895	$ 219,195	$ 252,009	$ 235,730	$ 254,229	$ 223,460	$ 225,588	$ 164,749	$ 147,452	$ 133,685	$ 145,928
Orchard Wind 4 QF	$ 2,292,210	$ 171,662	$ 118,895	$ 219,195	$ 251,592	$ 235,730	$ 254,274	$ 223,460	$ 225,588	$ 164,749	$ 147,452	$ 133,685	$ 145,928
Pavant II Solar QF	$ 5,849,871	$ 240,093	$ 293,160	$ 433,619	$ 500,475	$ 597,794	$ 649,155	$ 825,386	$ 774,689	$ 591,181	$ 430,750	$ 280,517	$ 233,053
Pioneer Wind Park I QF	$ 10,665,762	$ 1,312,186	$ 930,260	$ 1,189,464	$ 900,854	$ 712,752	$ 647,784	$ 660,578	$ 679,609	$ 450,955	$ 824,756	$ 1,259,911	$ 1,096,655
Power County North Wind QF	$ 6,180,712	$ 480,893	$ 628,902	$ 604,846	$ 538,724	$ 402,077	$ 384,669	$ 421,060	$ 418,091	$ 432,807	$ 570,734	$ 596,542	$ 701,368
Power County South Wind QF	$ 5,498,780	$ 424,333	$ 552,983	$ 546,339	$ 493,378	$ 347,184	$ 346,398	$ 371,860	$ 389,130	$ 382,558	$ 498,453	$ 537,476	$ 608,687
Roseburg Dillard QF	$ 2,144,928	$ 165,887	$ 217,686	$ 158,169	$ 175,020	$ 240,890	$ 128,909	$ 272,096	$ 184,147	$ 115,915	$ 96,035	$ 139,801	$ 250,374
Sage I Solar QF	$ 2,224,685	$ 79,115	$ 78,138	$ 185,750	$ 201,479	$ 231,609	$ 255,841	$ 332,541	$ 326,288	$ 205,038	$ 152,736	$ 102,280	$ 73,871
Sage II Solar QF	$ 2,223,183	$ 79,198	$ 78,231	$ 185,945	$ 201,695	$ 230,934	$ 256,127	$ 330,821	$ 326,646	$ 204,200	$ 152,889	$ 102,691	$ 73,807
Sage III Solar QF	$ 1,830,073	$ 66,690	$ 65,104	$ 153,415	$ 164,218	$ 189,832	$ 209,266	$ 269,677	$ 266,077	$ 168,341	$ 128,126	$ 86,686	$ 62,640
Spanish Fork Wind 2 QF	$ 2,833,148	$ 227,426	$ 183,910	$ 209,400	$ 162,146	$ 157,880	$ 220,088	$ 302,647	$ 322,851	$ 276,043	$ 250,057	$ 256,401	$ 264,297
Sunnyside QF	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sweetwater Solar QF	$ 7,551,390	$ 252,907	$ 362,894	$ 547,261	$ 667,685	$ 791,264	$ 950,104	$ 1,086,493	$ 1,005,887	$ 790,122	$ 610,411	$ 290,621	$ 195,741
Tesoro QF	$ 213,059	$ 40,263	$ 43,016	$ 28,705	$ 8,564	$ 1,746	$ 1,858	$ 99	$ 1,906	$ 7,625	$ 7,561	$ 14,833	$ 56,883
Three Peaks Solar QF	$ 8,973,114	$ 440,505	$ 497,322	$ 648,798	$ 859,439	$ 938,938	$ 956,823	$ 1,133,177	$ 1,073,990	$ 839,474	$ 722,120	$ 463,326	$ 399,202
Threemile Canyon Wind QF	$ 2,018,678	$ 88,630	$ 181,791	$ 158,295	$ 201,476	$ 206,750	$ 240,870	$ 244,129	$ 200,458	$ 142,666	$ 157,378	$ 108,629	$ 87,605
Utah Pavant Solar QF	$ 7,159,995	$ 303,631	$ 346,282	$ 509,076	$ 604,917	$ 784,942	$ 694,317	$ 1,063,896	$ 901,307	$ 793,052	$ 493,588	$ 342,653	$ 322,334
Utah Red Hills Solar QF	$ 10,473,163	$ 478,923	$ 590,625	$ 677,548	$ 907,822	$ 1,146,134	$ 1,000,877	$ 1,534,779	$ 1,279,128	$ 1,213,095	$ 671,655	$ 517,784	$ 454,792
Skysol Solar QF	$ 6,466,196	$ 337,321	$ 346,440	$ 521,412	$ 573,358	$ 628,554	$ 807,383	$ 867,608	$ 760,039	$ 566,178	$ 483,488	$ 285,341	$ 289,072
Qualifying Facilities Total	$ 309,614,622	$ 21,415,669	$ 22,968,423	$ 26,137,861	$ 26,271,233	$ 28,068,864	$ 28,815,598	$ 33,476,466	$ 31,106,801	$ 26,639,511	$ 23,604,867	$ 21,064,579	$ 20,044,748
Mid-Columbia Contracts													
Douglas - Wells	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Grant Reasonable	$ (15,474,138)	$ (1,289,511)	$ (1,289,511)	$ (1,289,511)	$ (1,289,511)	$ (1,289,511)	$ (1,289,511)	$ (1,289,511)	$ (1,289,511)	$ (1,289,511)	$ (1,289,511)	$ (1,289,511)	$ (1,289,511)
Grant Meaningful Priority	$ 109,742,672	$ 9,145,223	$ 9,145,223	$ 9,145,223	$ 9,145,223	$ 9,145,223	$ 9,145,223	$ 9,145,223	$ 9,145,223	$ 9,145,223	$ 9,145,223	$ 9,145,223	$ 9,145,223
Grant Surplus	$ 2,532,591	$ 211,049	$ 211,049	$ 211,049	$ 211,049	$ 211,049	$ 211,049	$ 211,049	$ 211,049	$ 211,049	$ 211,049	$ 211,049	$ 211,049
Mid-Columbia Contracts Total	$ 96,801,125	$ 8,066,760	$ 8,066,760	$ 8,066,760	$ 8,066,760	$ 8,066,760	$ 8,066,760	$ 8,066,760	$ 8,066,760	$ 8,066,760	$ 8,066,760	$ 8,066,760	$ 8,066,760
Total Long Term Firm Purchases	$ 682,662,188	$ 54,816,833	$ 52,709,673	$ 57,952,012	$ 55,724,119	$ 56,878,728	$ 57,046,466	$ 63,931,342	$ 60,693,341	$ 57,196,557	$ 56,510,135	$ 54,406,165	$ 54,796,817
Storage & Exchange													
Rush lake_BESS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Fremont Solar_BESS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Green River Energy Center_BESS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Faraday Solar_BESS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Umpqua Storage Placeholder	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Cowlitz Swift	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
EWEB FC I	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
PSCo Exchange	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
PSCO FC III	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
SCL State Line	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Storage & Exchange	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Short Term Firm Purchases													
COB	16,121,750	1,934,400	1,785,600	1,929,750	-	-	-	3,536,000	3,536,000	3,400,000	-	-	-
Colorado	-	-	-	-	-	-	-	-	-	-	-	-	-
Four Corners	-	-	-	-	-	-	-	-	-	-	-	-	-
Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-
Mead	-	-	-	-	-	-	-	-	-	-	-	-	-
Mid Columbia	13,299,800	-	-	-	-	-	-	4,484,900	4,484,900	4,330,000	-	-	-
Mona	-	-	-	-	-	-	-	-	-	-	-	-	-
NOB	-	-	-	-	-	-	-	-	-	-	-	-	-
Palo Verde	-	-	-	-	-	-	-	-	-	-	-	-	-
SP15	-	-	-	-	-	-	-	-	-	-	-	-	-
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	-	-	-	-	-	-	-	-	-	-	-	-
West Main	-	-	-	-	-	-	-	-	-	-	-	-	-
Wyoming	-	-	-	-	-	-	-	-	-	-	-	-	-
0	227,256,579	-	-	-	15,518,466	12,726,253	12,021,138	42,106,793	53,982,301	43,506,176	15,024,096	14,395,898	17,975,459
Total Short Term Firm Purchases	256,678,129	1,934,400	1,785,600	1,929,750	15,518,466	12,726,253	12,021,138	50,127,693	62,003,201	51,236,176	15,024,096	14,395,898	17,975,459
System Balancing Purchases													
COB	24,910,574	2,102,626	3,935,250	730,402	201,752	128,969	740,872	4,762,698	6,400,538	2,165,235	906,215	916,265	1,919,751
Four Corners	23,702,982	3,210,720	2,470,111	1,787,300	847,097	673,829	656,083	2,751,747	2,209,017	2,128,161	2,153,533	2,327,422	2,487,961
Mead	855,154	417,657	(13,259)	764,464	(14,040)	-	(163,123)	-	(102,054)	(94,128)	220,149	-	(160,512)
Mid Columbia	239,406,694	53,212,699	21,712,146	11,231,719	3,484,324	1,712,197	8,017,573	31,709,536	27,872,948	6,455,817	18,578,755	19,838,299	35,580,682
Mona	26,465,453	3,696,663	2,598,321	828,776	880,165	966,994	535,426	2,256,512	2,338,665	1,111,499	3,103,525	2,497,653	5,651,253
NOB	61,953,918	8,970,260	4,683,415	3,347,898	1,258,312	831,170	1,701,558	11,609,150	9,777,713	3,093,160	4,638,124	5,164,797	6,878,362
Palo Verde	11,955,494	3,958,841	91,453	752,543	168,322	362,858	154,002	224,967	700,692	12,366	2,130,461	1,109,405	2,289,582
EIM Imports/Exports	(105,320,697)	(11,300,075)	(8,327,383)	(7,127,129)	(6,353,110)	(5,748,156)	(5,569,531)	(11,395,678)	(12,530,393)	(10,700,168)	(6,904,343)	(7,890,338)	(11,474,394)
Emergency Purchases	7,631,095	10,378	-	-	-	-	159,103	2,788,351	4,664,809	-	-	-	8,453
Total System Balancing Purchases	291,560,668	64,279,770	27,150,055	12,315,973	472,823	(1,072,138)	6,231,964	44,707,283	41,331,935	4,171,942	24,826,419	23,963,505	43,181,138
Total Purchased Power & Net Interchange	1,230,900,984	121,031,003	81,645,328	72,197,735	71,715,408	68,532,843	75,299,568	158,766,318	164,028,477	112,604,674	96,360,649	92,765,568	115,953,413
Wheeling & U. of F. Expense													
Firm Wheeling	190,983,160	20,254,042	13,959,905	15,042,470	14,859,633	14,055,026	15,467,371	17,559,023	17,035,357	15,499,899	15,498,749	15,590,934	16,160,750
C&T EIM Admin fee	2,739,646	230,970	222,455	285,739	237,139	241,142	256,561	238,944	221,226	240,569	181,475	188,935	194,490
ST Firm & Non-Firm	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Wheeling & U. of F. Expense	193,722,805	20,485,012	14,182,360	15,328,209	15,096,773	14,296,168	15,723,932	17,797,967	17,256,584	15,740,468	15,680,224	15,779,869	16,355,240
Coal Fuel Burn Expense													
Colstrip	20,409,661	1,688,633	1,624,942	1,744,010	1,531,838	1,232,839	1,630,404	2,065,187	2,132,075	1,647,568	1,749,869	1,621,793	1,740,501
Craig	20,301,172	1,832,073	1,490,473	1,634,813	1,435,125	1,510,580	1,787,536	1,906,765	1,941,537	1,912,331	1,837,520	1,356,321	1,656,098
Dave Johnston	52,461,316	4,803,291	4,470,087	4,309,687	2,893,039	4,575,401	4,259,682	5,151,139	4,908,875	5,199,866	3,917,137	3,854,273	4,118,839
Hayden	10,300,354	892,450	777,756	843,993	812,501	828,138	860,165	955,234	942,800	848,864	546,757	741,361	1,250,333
Hunter	239,968,968	20,064,623	18,416,888	17,073,318	15,179,609	20,473,510	21,096,823	22,460,990	22,288,811	21,360,069	21,257,276	20,391,879	19,905,172
Huntington	172,065,535	12,053,675	13,328,726	15,644,451	15,452,401	14,586,990	15,195,365	15,539,958	16,198,897	16,324,147	11,627,220	14,654,086	11,459,619
Jim Bridger	106,868,456	12,008,630	11,146,114	8,462,392	5,571,554	3,985,838	6,161,422	13,935,740	13,233,972	8,248,179	7,391,758	9,200,377	7,522,479
Naughton	33,496,936	5,570,082	4,511,815	1,677,663	917,257	1,674,704	1,971,845	2,996,568	3,279,289	1,461,340	1,894,138	2,527,820	5,014,416
Wyodak	21,361,749	2,089,977	2,019,781	2,196,699	1,886,473	1,517,077	1,577,980	1,997,928	1,472,012	1,872,998	1,280,405	1,431,363	2,019,056
Total Coal Fuel Burn Expense	677,234,146	61,003,433	57,786,582	53,587,026	45,679,797	50,385,076	54,541,223	67,009,508	66,398,268	58,875,362	51,502,082	55,779,274	54,686,513
Gas Fuel Burn Expense													
Chehalis	87,932,300	17,730,002	12,988,074	5,439,817	5,775,866	1,110,360	1,380,115	6,908,175	6,680,242	3,195,283	5,601,315	6,466,385	14,656,665
Currant Creek	55,178,984	10,352,616	6,351,642	4,933,934	3,967,082	1,999,838	2,246,059	2,618,679	3,338,847	1,725,432	820,029	5,095,712	11,729,114
Gadsby	24,023,980	3,134,941	2,734,544	1,770,252	1,343,891	953,059	1,173,508	2,069,112	2,090,848	1,262,524	1,595,686	2,483,775	3,411,839
Gadsby CT	15,127,165	1,868,054	1,622,374	1,005,039	1,040,568	627,195	784,266	1,348,339	1,193,738	885,484	1,127,085	1,703,551	1,921,472
Hermiston	33,946,374	4,574,089	3,792,321	1,886,992	-	994,576	2,410,156	3,315,057	3,045,508	2,397,483	2,642,059	3,496,226	5,391,907
Jim Bridger - Gas	75,876,545	9,688,260	7,215,077	5,187,232	3,652,011	2,838,195	5,722,591	9,586,794	8,795,418	5,494,092	4,746,999	5,232,612	7,717,265
Lake Side 1	90,958,233	13,476,362	9,612,123	6,773,374	4,648,234	4,391,220	5,651,729	7,113,697	7,375,649	6,496,237	6,603,963	6,710,939	12,104,707
Lake Side 2	86,522,692	5,187,238	5,062,192	7,188,096	5,312,766	3,980,272	5,906,605	8,285,045	8,526,084	6,913,751	7,093,856	8,684,025	14,382,762
Naughton - Gas	15,554,484	2,544,777	2,042,586	1,213,830	136,405	664,144	1,120,256	1,714,020	2,242,676	1,078,272	957,689	827,473	1,012,356
Total Gas Fuel Burn													
Gas Physical	(2,287,887)	(842,499)	(565,488)	(166,005)	(12,072)	5,929	(48,792)	(198,020)	(206,320)	(188,787)	(65,833)	-	-
Gas Swaps	8,201,542	(8,214,187)	(1,920,205)	10,091,778	3,516,300	4,392,971	3,194,588	109,198	(375,914)	420,788	1,775,564	579,900	(5,369,239)
Clay Basin Gas Storage	(1,574,818)	(614,735)	(449,972)	(113,324)	51,739	51,739	51,739	51,739	51,739	51,739	51,739	(236,847)	(522,111)
Pipeline Reservation Fee	47,508,715	3,910,818	3,845,267	3,910,124	3,958,308	3,999,386	3,990,375	3,988,868	3,989,945	3,975,115	3,990,701	3,958,010	3,991,798
Total Gas Fuel Burn Expense	536,968,308	62,795,737	52,330,536	49,121,139	33,391,099	26,008,884	33,583,195	46,910,702	46,748,459	33,707,413	36,940,851	45,001,760	70,428,534

Other Generation Expense													
Blundell	$ 5,548,069	$ 426,194	$ 262,756	$ 516,438	$ 518,878	$ 295,633	$ 492,113	$ 481,258	$ 506,730	$ 491,247	$ 508,536	$ 506,047	$ 542,238
Blundell Bottoming Cycle	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Cedar Springs Wind II	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dunlap I Wind	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Ekola Flats Wind	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Foote Creek I Wind	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Foote Creek II Wind	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Foote Creek III Wind	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Foote Creek IV 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	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Rock Creek 1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Rock Creek 2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Rock River 1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Integration Charge	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Other Generation Expense	$ 5,548,069	$ 426,194	$ 262,756	$ 516,438	$ 518,878	$ 295,633	$ 492,113	$ 481,258	$ 506,730	$ 491,247	$ 508,536	$ 506,047	$ 542,238
Net Power Cost	**$ 2,382,431,518**	**$ 227,782,828**	**$ 186,459,172**	**$ 179,080,282**	**$ 155,876,231**	**$ 153,015,733**	**$ 169,779,529**	**$ 260,409,610**	**$ 261,925,709**	**$ 180,062,318**	**$ 184,561,674**	**$ 192,239,767**	**$ 231,238,666**

Case No. PAC-E-24-04
Exhibit No. 24
Witness: Ramon J. Mitchell

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Ramon J. Mitchell

Aurora Validation

May 2024

Net Power Cost Report
-- 12 months ended December 2021

Aurora Validation NPC Report

	Total	1/1/2021	2/1/2021	3/1/2021	4/1/2021	5/1/2021	6/1/2021	7/1/2021	8/1/2021	9/1/2021	10/1/2021	11/1/2021	12/1/2021
							$						
Special Sales For Resale													
Long Term Firm Sales													
Black Hills Losses_S	**308,860**	26,315	21,811	23,518	22,569	21,526	33,190	28,307	25,794	26,552	26,173	25,272	27,832
Black Hills Sale-MC_S	**3,714,881**	352,854	345,348	381,005	260,897	132,813	168,939	358,954	334,088	341,594	352,854	331,273	354,262
Black Hills Sale-UTS_S	**2,095,040**	178,500	147,946	159,524	153,092	146,016	225,135	192,008	174,962	180,108	177,535	171,424	188,792
Black Hills Sale-WYE_S	**1,789,443**	152,463	126,365	136,255	130,761	124,717	192,295	164,000	149,441	153,836	151,638	146,419	161,253
Leaning Juniper Revenue_S	**105,254**	7,601	7,384	9,260	5,355	4,684	6,043	14,266	16,102	10,939	7,961	6,724	8,936
Hurricane Sale_S	**7,474**	623	623	623	623	623	623	623	623	623	623	623	623
Total Long Term Firm Sales	**8,020,951**	**718,356**	**649,476**	**710,184**	**573,296**	**430,379**	**626,225**	**758,158**	**701,009**	**713,652**	**716,784**	**681,735**	**741,698**
Short Term Firm Sales													
STF Borah_S	**0**	0	0	0	0	0	0	0	0	0	0	0	0
STF COB_S	**0**	0	0	0	0	0	0	0	0	0	0	0	0
STF Colorado_S	**0**	0	0	0	0	0	0	0	0	0	0	0	0
STF Four Corners_S	**21,354,660**	3,522,890	2,974,080	3,095,370	1,977,600	1,958,400	1,977,600	0	0	0	1,971,460	1,905,800	1,971,460
STF Mead_S	**0**	0	0	0	0	0	0	0	0	0	0	0	0
STF Mid Columbia_S	**0**	0	0	0	0	0	0	0	0	0	0	0	0
STF Mona_S	**7,750,000**	1,277,800	1,202,400	1,345,800	338,000	325,000	338,000	0	0	0	985,000	953,000	985,000
STF Palo Verde_S	**23,424,050**	3,801,450	3,397,800	3,751,050	1,877,100	1,834,950	1,877,100	0	0	0	2,320,550	2,243,500	2,320,550
STF PP-GC_S	**0**	0	0	0	0	0	0	0	0	0	0	0	0
STF Wyoming East_S	**0**	0	0	0	0	0	0	0	0	0	0	0	0
STF Wyoming North_S	**0**	0	0	0	0	0	0	0	0	0	0	0	0
Total Short Term Firm Sales	**52,528,710**	**8,602,140**	**7,574,280**	**8,192,220**	**4,192,700**	**4,118,350**	**4,192,700**	**0**	**0**	**0**	**5,277,010**	**5,102,300**	**5,277,010**
System Balancing Sales													
COB-Sale	**30,427,339**	3,321,041	2,293,355	2,180,958	1,039,510	1,269,402	1,794,325	2,202,105	2,341,634	2,079,633	3,621,494	3,901,647	4,382,234
Four Corners-Sale	**42,302,885**	3,616,086	2,682,091	1,824,757	2,167,706	1,285,084	2,332,335	6,126,247	5,688,306	5,761,445	3,516,089	3,408,296	3,894,444
Mead-Sale	**27,629,244**	3,348,249	2,397,171	1,442,945	926,949	1,123,344	1,722,920	2,366,515	3,561,802	3,095,697	2,591,993	2,557,454	2,494,205
Mid Columbia-Sale	**34,612,093**	4,897,083	2,708,596	981,339	1,039,686	551,854	1,601,827	4,489,554	5,590,328	4,654,937	3,100,223	2,428,095	2,568,571
Mona-Sale	**21,211,278**	2,080,627	1,218,820	160,368	985,792	1,033,466	1,965,544	2,312,725	2,418,449	5,456,820	1,344,863	1,112,031	1,121,774
NOB-Sale	**5,309,085**	0	0	71,541	695,008	217,231	90,618	1,093,834	1,576,831	627,172	40,264	76,189	820,397
Palo Verde-Sale	**28,708,926**	(155,506)	(133,364)	(146,895)	850,630	979,874	1,252,619	8,421,419	9,324,164	6,125,457	683,077	695,432	812,019
Trapped Energy Sale	**101,435**	0	0	93,029	0	500	0	0	0	0	0	7,906	0
Total System Balancing Sales	**190,302,286**	**17,107,580**	**11,166,669**	**6,608,042**	**7,705,281**	**6,460,755**	**10,760,187**	**27,012,400**	**30,501,514**	**27,801,162**	**14,898,003**	**14,187,049**	**16,093,644**
Total Special Sales For Resale	**250,851,948**	**26,428,076**	**19,390,425**	**15,510,447**	**12,471,277**	**11,009,484**	**15,579,112**	**27,770,557**	**31,202,522**	**28,514,815**	**20,891,797**	**19,971,084**	**22,112,352**
Purchased Power & Net Interchange													
Long Term Firm Solar Purchases													
SR_Cove Mountain_P	**3,863,928**	185,318	194,698	339,380	369,457	425,244	457,334	443,628	419,764	359,961	289,769	208,202	171,172
SR_Cove Mountain II_P	**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
SR_Hunter_P	**7,122,377**	374,917	425,032	647,514	675,791	770,602	797,428	758,093	712,634	664,479	567,050	402,182	326,655
SR_Milford_P	**7,081,167**	358,636	412,994	609,192	677,611	796,634	839,927	747,990	720,079	671,702	541,718	394,119	310,565
SR_Milican_P	**2,668,657**	90,574	138,221	204,961	257,983	306,198	333,291	375,334	331,655	266,914	174,771	111,940	76,815
SR_Old Mill_P	**831,936**	26,484	46,325	52,432	79,715	99,415	118,812	111,013	94,492	83,002	59,410	33,957	26,880
SR_Pavant III_P	**2,686,563**	111,395	134,597	228,283	257,419	312,381	326,190	313,964	299,310	261,828	215,287	136,955	88,955
SR_Prineville_P	**1,772,986**	60,175	91,830	136,171	171,397	203,430	221,430	249,362	220,343	177,331	116,113	74,370	51,034
SR_Sigurd_P	**2,905,614**	0	0	0	0	0	23,671	660,236	605,233	565,052	458,516	322,228	270,678
Total Long Term Firm Solar Purchases	**29,276,799**	**1,236,034**	**1,472,372**	**2,246,646**	**2,518,075**	**2,942,439**	**3,146,785**	**3,688,242**	**3,432,133**	**3,078,876**	**2,451,256**	**1,712,562**	**1,351,377**
Long Term Firm Wind Purchases													
WD_Cedar Springs_P	**11,723,272**	1,348,848	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
WD_Cedar Springs III_P	**8,908,094**	1,025,293	832,068	784,236	772,111	631,271	565,347	564,366	445,199	628,829	828,668	811,823	1,018,881
WD_Combine Hills_P	**5,369,070**	372,722	451,621	547,613	547,338	465,613	400,323	451,806	378,748	357,771	372,201	456,360	566,954
WD_Rock River_P	**3,978,379**	647,624	502,957	528,679	435,960	284,843	262,622	181,185	193,222	262,771	490,382	188,135	0
WD_Three Buttes_P	**20,662,793**	2,790,662	1,806,920	2,135,555	1,618,738	1,425,615	1,202,984	807,053	950,560	1,186,425	1,734,559	2,352,374	2,651,346
WD_Top of the World_P	**40,686,139**	5,436,528	3,612,747	4,244,159	3,270,671	2,907,362	2,399,809	1,720,419	1,872,120	2,296,835	3,513,194	4,491,633	4,920,662
WD_Wolverine Creek_P	**10,259,067**	760,539	888,634	1,132,687	1,040,512	787,597	844,716	669,522	637,856	752,718	827,853	962,861	953,572
Total Long Term Firm Wind Purchases	**101,586,814**	**12,382,216**	**9,190,148**	**10,405,173**	**8,701,365**	**7,333,126**	**6,419,682**	**5,137,134**	**5,063,696**	**6,312,848**	**8,857,391**	**10,331,529**	**11,452,507**

Long Term Firm Hydro Purchases													
Douglas - Wells_P	**0**	0	0	0	0	0	0	0	0	0	0	0	0
Grant Wanapum Dev_P	**0**	0	0	0	0	0	0	0	0	0	0	0	0
Grant Priest Rapids Dev_P	**2,072,011**	172,668	172,668	172,668	172,668	172,668	172,668	172,668	172,668	172,668	172,668	172,668	172,668
Grant Reasonable_P	**0**	0	0	0	0	0	0	0	0	0	0	0	0
Meaningful Priority_P	**25,591,632**	2,132,636	2,132,636	2,132,636	2,132,636	2,132,636	2,132,636	2,132,636	2,132,636	2,132,636	2,132,636	2,132,636	2,132,636
Total Long Term Firm Hydro Purchases	**27,663,643**	**2,305,304**	**2,305,304**	**2,305,304**	**2,305,304**	**2,305,304**	**2,305,304**	**2,305,304**	**2,305,304**	**2,305,304**	**2,305,304**	**2,305,304**	**2,305,304**
Long Term Firm Other Purchases													
APS Supp Coal_P	**0**	0	0	0	0	0	0	0	0	0	0	0	0
APS Supp Other_P	**0**	0	0	0	0	0	0	0	0	0	0	0	0
Deseret Purchase_P	**33,411,787**	2,792,683	2,843,537	2,655,766	2,590,568	2,513,634	2,552,753	2,979,150	2,979,150	2,947,854	2,946,550	2,674,022	2,936,119
CoolKeeper Reserve_P	**0**	0	0	0	0	0	0	0	0	0	0	0	0
Eagle Mountain-UAMPS1626656_P	**546,803**	16,316	15,456	17,263	17,566	16,566	68,739	118,561	120,073	82,257	0	35,667	38,341
Eagle Mountain-UAMPS1626657_P	**2,068,850**	140,576	125,592	108,610	111,251	137,604	215,863	318,185	287,362	158,816	156,349	118,011	190,629
Gemstate Purchase_P	**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
Hurricane Purchase_P	**165,480**	13,790	13,790	13,790	13,790	13,790	13,790	13,790	13,790	13,790	13,790	13,790	13,790
MacCorp Buythru_P	**0**	0	0	0	0	0	0	0	0	0	0	0	0
MagCorp Reserves_P	**4,828,040**	401,000	392,980	401,000	409,020	401,000	409,020	413,030	392,980	388,970	372,930	433,080	413,030
Monsanto Buythru_P	**0**	0	0	0	0	0	0	0	0	0	0	0	0
Monsanto Reserves_P	**20,000,000**	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
Nucor Reserve_P	**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
PGE Cove Replacement_P	**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
Small East Purchase_P	**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
GEO_Soda Lake_P	**8,293,091**	822,675	726,731	767,167	706,207	682,902	572,441	516,487	545,410	595,644	725,349	782,467	849,611
Biomass One_NonGen_P	**(1,241,584)**	0	0	0	0	(626,892)	(614,693)	0	0	0	0	0	0
Total Long Term Firm Other Purchases	**77,089,163**	**6,605,080**	**6,536,166**	**6,381,635**	**6,266,441**	**5,556,705**	**5,635,983**	**6,777,296**	**6,756,835**	**6,605,352**	**6,632,993**	**6,475,113**	**6,859,562**
Total Long Term Firm Purchases	**235,616,418**	**22,528,634**	**19,503,990**	**21,338,758**	**19,791,185**	**18,137,574**	**17,507,754**	**17,907,976**	**17,557,967**	**18,302,379**	**20,246,944**	**20,824,508**	**21,968,750**
Solar Qualifying Facilities													
SR_Oregon CO Post-MSP_QF	**2,300,677**	77,816	111,034	162,715	227,354	268,324	306,338	316,611	288,014	228,682	160,007	82,963	70,817
SR_Oregon WM Post-MSP_QF	**18,241,080**	616,969	880,342	1,290,101	1,802,595	2,127,430	2,428,826	2,510,274	2,283,543	1,813,121	1,268,624	657,777	561,480
SR_Utah Post-MSP_QF	**10,247,886**	698,791	728,593	879,205	912,885	993,150	1,011,417	961,497	945,082	895,465	834,750	721,194	665,857
SR_Chiloquin_OR_QF	**0**	0	0	0	0	0	0	0	0	0	0	0	0
SR_Enterprise I_UT_QF	**12,563,620**	617,060	756,869	980,643	1,117,040	1,257,239	1,382,201	1,554,604	1,501,679	1,181,692	958,192	710,651	545,749
SR_Escalante I_UT_QF	**11,601,699**	565,497	685,083	883,730	1,015,842	1,191,042	1,306,249	1,436,464	1,391,658	1,094,914	874,325	648,325	508,570
SR_Escalante II_UT_QF	**10,921,956**	531,489	645,513	832,363	955,501	1,126,570	1,235,899	1,359,761	1,304,267	1,031,738	818,253	606,453	474,150
SR_Escalante III_UT_QF	**10,520,814**	517,551	627,998	806,130	929,680	1,098,976	1,206,562	1,321,201	1,268,973	1,003,181	750,478	555,442	434,642
SR_Glen Canyon A_UT_QF	**0**	0	0	0	0	0	0	0	0	0	0	0	0
SR_Glen Canyon B_UT_QF	**0**	0	0	0	0	0	0	0	0	0	0	0	0
SR_Granite Mountain East_UT_QF	**10,913,762**	548,826	618,770	895,200	990,553	1,158,652	1,258,453	1,338,832	1,261,327	978,568	810,799	585,874	467,909
SR_Granite Mountain West_UT_QF	**7,220,476**	363,517	409,549	593,814	657,018	766,608	830,757	887,222	834,460	645,109	536,218	387,167	309,035
SR_Iron Springs_UT_QF	**11,200,375**	634,276	666,108	897,183	1,017,894	1,130,821	1,283,101	1,346,598	1,318,720	1,006,219	817,161	582,281	500,011
SR_Pavant_UT_QF	**5,611,810**	208,301	240,534	410,490	470,172	563,656	662,527	772,098	721,479	602,883	450,433	279,646	229,591
SR_Pavant II_UT_QF	**4,310,018**	177,389	225,178	346,901	399,214	454,357	476,933	558,197	543,942	425,102	330,218	205,953	166,635
SR_Red Hills_UT_QF	**11,565,267**	484,032	621,327	787,699	1,034,403	1,204,545	1,240,487	1,530,453	1,463,983	1,326,490	812,004	594,449	465,395
SR_Sage I_WY_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
SR_Sage II_WY_QF	**2,272,891**	80,764	79,986	190,360	206,223	235,208	263,006	338,244	333,977	208,784	155,870	105,000	75,469
SR_Sage III_WY_QF	**1,870,483**	68,007	66,563	157,053	167,907	192,623	214,874	275,731	272,050	172,117	130,624	88,886	64,050
SR_Sweetwater_WY_QF	**7,797,372**	259,240	374,746	567,021	689,492	814,365	985,566	1,121,978	1,038,739	815,928	628,052	300,112	202,134
SR_Three Peaks_UT_QF	**8,452,877**	411,976	477,957	625,721	834,509	860,254	911,132	1,042,847	998,463	794,907	672,624	450,021	372,466
SR_Tumbleweed_OR_QF	**0**	0	0	0	0	0	0	0	0	0	0	0	0
Total Solar Qualifying Facilities	**149,883,520**	**6,942,181**	**8,296,040**	**11,496,488**	**13,634,285**	**15,678,816**	**17,267,036**	**19,010,493**	**18,103,968**	**14,433,446**	**11,164,343**	**7,667,064**	**6,189,359**
Wind Qualifying Facilities													
WD_Oregon Post-MSP_QF	**7,200,085**	516,989	469,240	690,448	782,327	721,027	775,598	684,669	652,282	479,718	462,384	467,492	497,910
WD_Chopin_OR_QF	**0**	0	0	0	0	0	0	0	0	0	0	0	0
WD_Five Pine_ID_QF	**8,399,980**	515,184	843,295	749,871	802,886	485,844	529,260	630,392	591,216	751,568	738,975	881,157	880,333
WD_Latigo Wind Park_UT_QF	**9,672,433**	1,007,976	917,725	1,119,717	895,550	857,781	745,592	682,684	563,374	621,378	790,071	708,277	762,309
WD_Monticello_UT_QF	**0**	0	0	0	0	0	0	0	0	0	0	0	0
WD_Mountain Wind 1_WY_QF	**8,916,081**	1,397,706	1,044,898	869,816	693,033	479,607	498,327	410,860	440,933	454,827	672,574	927,984	1,025,516
WD_Mountain Wind 2_WY_QF	**13,895,032**	2,038,486	1,566,199	1,352,529	1,078,715	750,862	890,296	761,456	734,168	757,712	1,009,556	1,435,298	1,519,756
WD_North Point_ID_QF	**18,786,578**	1,081,867	1,817,410	1,672,825	1,801,611	1,084,057	1,202,040	1,464,552	1,465,393	1,786,186	1,717,960	1,871,544	1,821,134
WD_Oregon Wind Farm_OR_QF	**12,468,786**	729,862	971,741	1,115,635	1,312,367	1,260,504	1,201,740	1,261,215	1,114,408	919,425	735,728	801,715	1,044,447
WD_Orem Family_OR_QF	**0**	0	0	0	0	0	0	0	0	0	0	0	0
WD_Pioneer Wind Park I_WY_QF	**10,639,652**	1,303,917	924,898	1,187,446	905,027	704,142	650,577	649,784	680,906	450,437	820,675	1,263,591	1,098,250
WD_Power County North_ID_QF	**5,460,338**	415,705	548,470	525,350	519,896	350,949	344,576	370,353	360,111	380,493	511,430	530,622	602,381
WD_Power County South_ID_QF	**4,865,045**	367,049	482,868	474,030	482,998	302,559	306,289	327,761	335,462	336,896	447,464	479,427	522,240
WD_Spanish Fork 2_UT_QF	**2,754,893**	217,428	177,317	204,533	160,625	154,092	210,748	289,637	315,766	271,043	242,506	250,579	260,620
WD_Threemile Canyon_OR_QF	**0**	0	0	0	0	0	0	0	0	0	0	0	0
Total Wind Qualifying Facilities	**103,058,904**	**9,592,169**	**9,764,061**	**9,962,201**	**9,435,034**	**7,151,426**	**7,355,043**	**7,533,363**	**7,254,020**	**7,209,682**	**8,149,323**	**9,617,687**	**10,034,896**

Other Qualifying Facilities													
California Pre Merger Pre-MSP_QF	**981,258**	91,344	121,650	139,635	189,175	178,961	121,479	40,661	13,623	9,962	9,370	16,818	48,582
California Post Merger Pre-MSP_QF	**29,542**	3,186	3,043	3,025	3,083	2,638	2,325	2,638	1,854	1,693	1,436	2,505	2,115
California Post Merger Post-MSP_QF	**1,456,200**	121,787	112,517	125,199	121,035	121,787	121,035	123,545	123,545	119,277	123,545	119,381	123,545
Idaho Pre Merger Pre-MSP_QF	**4,958,064**	344,783	308,524	392,179	443,898	588,668	585,708	527,676	348,862	344,348	322,121	383,309	367,989
Idaho Post Merger Pre-MSP_QF	**120,952**	5,666	5,917	13,514	18,531	11,795	14,462	13,405	9,064	7,353	6,781	8,797	5,666
Idaho Post Merger Post-MSP_QF	**2,751,508**	236,038	225,933	210,794	199,697	178,158	184,294	244,859	239,987	239,726	237,899	233,686	320,438
Oregon Pre Merger Pre-MSP_QF	**8,408,916**	714,509	661,242	742,175	851,029	849,743	758,373	666,101	666,393	721,883	572,965	533,515	670,985
Oregon Post Merger Pre-MSP_QF	**584,796**	47,831	41,135	61,541	100,349	97,645	84,416	31,946	18,992	18,727	12,349	27,155	42,711
Oregon Post Merger Post-MSP_QF	**14,109,749**	984,473	954,895	1,131,155	1,282,452	1,414,223	1,352,006	1,349,990	1,346,342	1,301,636	1,121,534	903,321	967,723
Utah N Post Merger Post-MSP_QF	**632,177**	46,396	49,136	55,415	53,863	62,149	61,998	48,793	55,340	48,604	50,933	53,978	45,574
Utah S Post Merger Post-MSP_QF	**632,177**	46,396	49,136	55,415	53,863	62,149	61,998	48,793	55,340	48,604	50,933	53,978	45,574
Washington Post Merger Post-MSP_QF	**218,736**	0	0	19	8,001	21,996	37,135	51,373	52,945	35,398	11,871	0	0
Wyoming Pre Merger Pre-MSP_QF	**0**	0	0	0	0	0	0	0	0	0	0	0	0
Wyoming Post Merger Pre-MSP_QF	**0**	0	0	0	0	0	0	0	0	0	0	0	0
Wyoming Post Merger Post-MSP_QF	**86,184**	10,091	8,471	10,115	6,257	4,967	2,992	8,382	7,360	4,207	5,944	6,878	10,520
Biomass One_OR_QF	**16,515,565**	1,240,650	1,202,754	1,328,737	1,605,809	1,642,614	1,605,809	1,455,965	1,407,485	1,392,619	1,454,920	1,426,918	751,284
DCFP_OR_QF	**117,193**	3,577	4,372	3,513	2,866	3,059	4,880	19,721	22,137	26,416	12,083	7,259	7,311
Roseburg Dillard_CA_QF	**982,171**	43,523	50,277	26,541	102,556	104,709	88,024	164,486	131,434	66,115	76,189	75,916	52,401
Sunnyside Base_UT_QF	**25,446,689**	1,926,944	1,794,251	2,230,743	1,509,783	2,271,849	2,278,852	2,438,937	2,404,628	2,262,028	1,952,501	2,278,541	2,097,630
Sunnyside Additional_UT_QF	**5,496,514**	411,090	388,623	462,527	451,598	469,488	470,673	497,779	491,970	467,826	474,327	470,621	439,990
Tesoro_UT_QF	**296,096**	46,096	34,206	27,450	19,189	25,292	6,946	13,491	20,976	19,011	19,842	20,127	43,471
Total Other Qualifying Facilities	**83,824,486**	**6,324,381**	**6,016,080**	**7,019,693**	**7,023,032**	**8,111,890**	**7,843,402**	**7,748,542**	**7,418,278**	**7,135,433**	**6,517,542**	**6,622,704**	**6,043,510**
Total Qualifying Facilities	**336,766,909**	**22,858,731**	**24,076,181**	**28,478,382**	**30,092,352**	**30,942,132**	**32,465,481**	**34,292,398**	**32,776,265**	**28,778,562**	**25,831,208**	**23,907,454**	**22,267,764**
Exchanges													
APS Exchange In-PPGC_P	**0**	0	0	0	0	0	0	0	0	0	0	0	0
APS Exchange In-FC_P	**0**	0	0	0	0	0	0	0	0	0	0	0	0
APS Exchange Out-PPGC_P	**0**	0	0	0	0	0	0	0	0	0	0	0	0
APS Exchange Out-FC_P	**0**	0	0	0	0	0	0	0	0	0	0	0	0
PSCol Exchange In_P	**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
PSCol Exchange Out_P	**0**	0	0	0	0	0	0	0	0	0	0	0	0
WD_SCL State Line Generation_P	**0**	0	0	0	0	0	0	0	0	0	0	0	0
SCL-Stateline Delivery_P	**0**	0	0	0	0	0	0	0	0	0	0	0	0
SCL-Stateline Losses_P	**0**	0	0	0	0	0	0	0	0	0	0	0	0
SCL-Stateline Reserves_P	**0**	0	0	0	0	0	0	0	0	0	0	0	0
Total Exchanges	**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													
STF Borah_P	**0**	0	0	0	0	0	0	0	0	0	0	0	0
STF COB_P	**0**	0	0	0	0	0	0	0	0	0	0	0	0
STF Colorado_P	**0**	0	0	0	0	0	0	0	0	0	0	0	0
STF Four Corners_P	**0**	0	0	0	0	0	0	0	0	0	0	0	0
STF Mead_P	**0**	0	0	0	0	0	0	0	0	0	0	0	0
STF Mid Columbia_P	**14,768,640**	1,621,000	1,556,160	1,750,680	0	0	1,216,800	2,912,000	2,912,000	2,800,000	0	0	0
STF Mona_P	**0**	0	0	0	0	0	0	0	0	0	0	0	0
STF Palo Verde_P	**678,500**	247,250	207,000	224,250	0	0	0	0	0	0	0	0	0
STF PP-GC_P	**0**	0	0	0	0	0	0	0	0	0	0	0	0
STF Wyoming East_P	**0**	0	0	0	0	0	0	0	0	0	0	0	0
STF Wyoming North_P	**0**	0	0	0	0	0	0	0	0	0	0	0	0
Total Short Term Firm Purchases	**15,447,140**	**1,868,250**	**1,763,160**	**1,974,930**	**0**	**0**	**1,216,800**	**2,912,000**	**2,912,000**	**2,800,000**	**0**	**0**	**0**
System Balancing Purchases													
COB	**13,650,632**	256,796	176,618	1,541,659	766,329	2,532,784	1,598,378	1,986,504	1,277,522	563,293	831,396	743,288	1,376,064
Four Corners	**18,532,479**	1,765,251	2,892,183	4,051,845	1,279,491	1,076,258	217,643	872,158	676,196	352,326	1,379,366	1,484,561	2,485,201
Mead	**5,635,494**	365,486	777,555	348,436	294,096	456,275	412,248	894,509	413,420	443,981	380,806	169,957	678,726
Mid Columbia	**69,840,592**	2,961,318	1,414,822	962,531	2,238,265	13,451,364	12,840,011	13,022,595	13,900,634	3,546,501	2,252,822	1,434,611	1,815,117
Mona	**8,736,656**	1,083,486	690,394	803,185	562,467	661,458	92,264	866,660	493,322	346,124	1,016,204	1,190,417	930,675
NOB	**11,488,657**	0	0	136,696	1,682,517	313,457	156,723	2,190,741	3,482,419	1,332,912	63,056	193,975	1,936,162
Palo Verde	**2,469,641**	675,237	564,123	515,725	79,395	79,395	79,395	79,395	79,395	79,395	79,395	79,395	79,395
Emergency Purchases	**1,933,211**	0	0	0	59,583	775,436	72,286	473,946	47,070	354,072	67,489	16,636	66,692
EIM Imports/Exports	**(59,250,810)**	(3,445,870)	(3,105,010)	(6,863,178)	(6,863,641)	(7,467,599)	(3,035,622)	(7,434,719)	(7,740,230)	(4,243,730)	(2,826,239)	(2,722,603)	(3,502,369)
Total System Balancing Purchases	**73,036,553**	**3,661,704**	**3,410,686**	**1,496,900**	**98,501**	**11,878,828**	**12,433,327**	**12,951,790**	**12,629,748**	**2,774,875**	**3,244,295**	**2,590,237**	**5,865,663**
Total Purchase Expenses	**666,267,021**	**51,367,319**	**49,204,017**	**53,738,969**	**50,432,038**	**61,408,533**	**64,073,362**	**68,514,163**	**66,325,980**	**53,105,815**	**49,772,447**	**47,772,200**	**50,552,178**
Wheeling Expenses													
Wheeling Expenses - East	**23,995,497**	2,219,922	2,390,245	2,269,358	2,207,351	1,635,627	1,914,090	1,728,308	1,692,073	2,055,323	1,763,481	2,190,283	1,929,437
Wheeling Expenses - West	**116,275,997**	9,811,383	9,417,188	9,833,558	9,701,806	8,965,309	9,514,241	9,218,342	9,372,759	9,720,813	9,853,080	10,010,925	10,856,596
Total Wheeling Expenses	**140,271,494**	**12,031,304**	**11,807,432**	**12,102,916**	**11,909,157**	**10,600,935**	**11,428,331**	**10,946,650**	**11,064,831**	**11,776,136**	**11,616,561**	**12,201,208**	**12,786,032**

Coal Fuel Costs													
Cholla 4	**0**	0	0	0	0	0	0	0	0	0	0	0	0
Colstrip 3	**6,743,536**	724,525	460,344	505,129	577,625	380,624	579,040	685,894	730,984	620,364	444,777	340,907	693,325
Colstrip 4	**7,257,302**	709,552	447,732	502,498	610,693	322,258	514,926	794,727	836,314	681,105	440,641	651,044	745,813
Craig 1	**8,763,907**	824,967	622,614	691,539	747,355	293,600	627,907	824,252	858,234	788,247	797,021	756,402	931,770
Craig 2	**9,161,302**	873,615	708,999	791,182	670,943	408,898	732,671	702,234	890,943	845,996	854,299	820,614	860,910
Dave Johnston 1	**8,434,015**	730,346	705,893	775,742	708,441	775,808	716,878	743,263	776,284	278,650	778,026	705,531	739,154
Dave Johnston 2	**7,754,005**	709,832	722,008	793,552	587,225	533,917	430,615	661,715	652,029	651,369	808,199	688,034	515,510
Dave Johnston 3	**15,400,725**	1,637,875	1,442,794	619,873	1,072,752	1,537,518	863,880	1,215,356	1,400,568	1,450,972	1,516,502	1,244,365	1,398,272
Dave Johnston 4	**23,843,984**	2,298,785	2,228,426	2,430,399	1,678,943	1,618,128	2,189,781	1,964,259	2,207,277	2,170,358	1,923,463	1,172,154	1,962,012
Hayden 1	**6,518,462**	572,263	473,256	539,817	527,516	621,051	565,885	626,932	549,133	335,977	508,879	603,705	594,048
Hayden 2	**4,353,641**	362,981	276,043	319,885	388,815	502,406	428,546	432,920	343,132	265,390	256,070	343,396	434,056
Hunter 1	**41,173,406**	3,921,773	2,967,374	1,687,380	2,658,292	2,726,535	3,616,013	3,963,715	4,057,193	3,716,762	3,976,571	3,805,619	4,076,179
Hunter 2	**26,065,012**	2,875,507	2,130,482	2,129,285	1,385,982	1,852,422	2,193,159	2,482,615	1,816,154	2,040,061	2,073,104	2,584,924	2,501,317
Hunter 3	**50,561,913**	4,782,836	3,631,652	3,670,041	2,350,165	3,943,947	4,171,685	4,735,171	5,074,824	4,417,382	4,436,911	4,702,258	4,645,042
Huntington 1	**60,145,415**	5,457,542	3,979,840	3,943,189	4,991,971	3,989,142	4,395,989	6,433,773	6,127,715	4,468,420	5,220,835	4,901,357	6,235,641
Huntington 2	**43,390,630**	3,929,290	2,084,775	2,489,016	3,159,220	2,572,348	2,930,819	4,826,207	5,397,127	4,065,968	1,907,699	4,246,904	5,781,257
Jim Bridger 1	**44,451,387**	2,984,935	2,618,409	2,894,337	3,781,950	1,887,600	2,781,931	5,563,463	5,610,212	4,748,675	3,814,928	4,309,198	3,455,750
Jim Bridger 2	**48,519,097**	3,581,861	3,031,949	3,194,427	2,376,725	2,925,493	3,719,856	5,817,880	5,208,470	5,028,788	4,904,166	4,318,646	4,410,836
Jim Bridger 3	**38,769,170**	2,568,113	2,108,772	2,558,268	3,387,973	2,487,063	3,303,153	4,537,483	5,111,074	4,069,382	2,515,083	3,165,380	2,957,427
Jim Bridger 4	**35,126,601**	2,819,482	2,260,864	2,640,948	2,947,085	2,444,086	2,613,908	4,508,884	4,281,763	2,022,148	2,338,833	2,967,531	3,281,069
Naughton 1	**32,861,448**	3,159,592	2,735,409	2,816,577	2,610,445	1,778,745	2,646,754	2,908,541	2,922,312	2,992,532	2,995,208	2,413,914	2,881,418
Naughton 2	**44,989,355**	4,267,375	3,608,743	3,623,729	3,836,804	3,501,728	3,440,209	3,759,965	3,935,783	3,716,798	4,053,936	3,878,647	3,365,638
Wyodak	**29,331,659**	2,665,998	2,596,607	2,858,330	2,549,670	2,837,949	2,204,888	2,706,063	2,551,464	2,386,598	2,416,783	2,007,256	1,550,053
Total Coal Fuel Costs	**593,615,974**	**52,459,045**	**41,842,983**	**42,475,143**	**43,606,590**	**39,941,264**	**45,668,492**	**60,895,310**	**61,338,987**	**51,761,943**	**48,981,933**	**50,627,786**	**54,016,497**
Gas Fuel Costs													
GS_Chehalis	**39,191,777**	5,601,806	6,850,667	5,000,964	399,342	0	526,745	3,952,845	3,842,001	3,053,599	3,995,823	1,442,305	4,525,679
GS_Currant Creek	**43,149,230**	3,945,536	5,068,986	3,965,335	2,567,360	527,000	2,866,258	5,005,347	3,611,548	3,760,304	2,560,237	4,822,141	4,449,178
GS_Currant Creek DF	**2,618,880**	246,907	302,755	237,606	151,756	33,290	155,738	310,092	217,979	206,945	159,648	290,171	305,993
GS_Gadsby 1	**1,500,904**	113,808	138,029	123,398	38,707	21,139	77,313	302,329	261,884	132,164	74,250	74,174	143,708
GS_Gadsby 2	**1,544,554**	106,788	111,251	105,308	60,446	63,419	96,089	273,185	250,801	141,443	78,103	97,828	159,893
GS_Gadsby 3	**2,501,997**	242,267	270,207	243,593	79,156	91,727	153,064	321,208	322,474	192,552	121,909	170,161	293,680
GS_Gadsby 4	**1,227,107**	210,235	101,469	0	27,130	2,266	31,215	208,132	218,050	123,748	69,923	68,870	166,067
GS_Gadsby 5	**1,178,719**	210,235	111,616	0	11,696	3,626	29,379	207,518	222,175	118,602	53,455	60,493	149,925
GS_Gadsby 6	**1,280,244**	210,235	142,056	0	14,970	0	22,034	215,727	226,455	139,508	61,666	77,286	170,307
GS_Hermiston 1	**13,465,460**	3,369,204	2,252,593	1,701,740	0	0	0	1,890,465	2,101,904	2,149,553	0	0	0
GS_Hermiston 2	**8,258,348**	0	0	0	1,300,107	301,995	585,250	0	0	0	1,650,244	1,995,280	2,425,472
GS_Lake Side 1	**50,609,195**	4,519,987	5,829,564	4,614,648	2,060,159	808,606	3,341,692	5,686,945	5,732,585	5,176,499	4,396,507	4,517,300	3,924,704
GS_Lake Side 1 DF	**1,411,980**	60,137	0	4,542	56,324	31,645	129,431	282,132	258,791	164,278	111,537	136,720	176,443
GS_Lake Side 2	**59,058,338**	6,060,646	6,527,223	5,744,565	3,750,550	1,805,471	3,893,581	5,414,014	5,368,840	4,684,680	4,953,688	4,533,242	6,321,837
GS_Lake Side 2 DF	**1,917,085**	67,549	5,857	30,896	108,461	55,289	121,837	333,354	318,119	197,238	168,692	169,799	339,995
GS_Naughton 3	**6,328,837**	202,467	160,436	199,615	108,007	168,133	400,542	1,267,035	1,147,091	551,778	433,359	369,884	1,320,489
Total Gas Fuel Costs	**235,242,654**	**25,167,807**	**27,872,708**	**21,972,211**	**10,734,169**	**3,913,607**	**12,430,168**	**25,670,328**	**24,100,696**	**20,792,893**	**18,889,042**	**18,825,655**	**24,873,372**
Gas Financials													
GS_Clay Basin Gas Storage	**(588,564)**	(334,019)	(307,763)	(216,982)	52,242	52,242	52,242	52,242	52,242	52,242	52,242	2,850	(98,348)
GS_Gas Physical - Chehalis	**0**	0	0	0	0	0	0	0	0	0	0	0	0
GS_Gas Physical - East	**84,248**	26,737	25,270	32,240	0	0	0	0	0	0	0	0	0
GS_Gas Physical - Hermiston	**(500,971)**	(105,851)	(83,235)	(56,541)	(25,945)	(23,006)	(23,393)	(50,730)	(49,843)	(45,141)	(37,288)	0	0
GS_Gas Swaps - Chehalis	**(880,780)**	(649,915)	(319,060)	88,195	0	0	0	0	0	0	0	0	0
GS_Gas Swaps - East	**(19,056,887)**	(3,887,012)	(2,992,150)	(1,327,188)	(534,300)	(308,760)	(399,300)	(2,547,968)	(2,611,285)	(2,249,700)	18,135	(364,800)	(1,852,560)
GS_Gas Swaps - Hermiston	**0**	0	0	0	0	0	0	0	0	0	0	0	0
GS_Pipeline Lateral - Chehalis	**601,800**	50,150	50,150	50,150	50,150	50,150	50,150	50,150	50,150	50,150	50,150	50,150	50,150
GS_Pipeline Main - Chehalis	**10,697,195**	891,433	891,433	891,433	891,433	891,433	891,433	891,433	891,433	891,433	891,433	891,433	891,433
GS_Pipeline Lateral - Currant Creek	**1,292,395**	107,700	107,700	107,700	107,700	107,700	107,700	107,700	107,700	107,700	107,700	107,700	107,700
GS_Pipeline - Hermiston	**2,533,944**	212,720	204,708	212,720	210,049	212,720	210,049	212,720	212,720	210,049	212,720	210,049	212,720
GS_Pipeline - Kern River Gas	**2,989,350**	253,890	229,320	253,890	245,700	253,890	245,700	253,890	253,890	245,700	253,890	245,700	253,890
GS_Pipeline - Lake Side 2	**5,334,796**	444,566	444,566	444,566	444,566	444,566	444,566	444,566	444,566	444,566	444,566	444,566	444,566
GS_Pipeline Lateral - Lake Side	**2,353,029**	196,086	196,086	196,086	196,086	196,086	196,086	196,086	196,086	196,086	196,086	196,086	196,086
GS_Pipeline - Naughton	**2,564,970**	213,748	213,748	213,748	213,748	213,748	213,748	213,748	213,748	213,748	213,748	213,748	213,748
GS_Pipeline Reservation Fees	**801,834**	66,820	66,820	66,820	66,820	66,820	66,820	66,820	66,820	66,820	66,820	66,820	66,820
GS_Pipeline - Southern System Expansion	**5,635,526**	469,627	469,627	469,627	469,627	469,627	469,627	469,627	469,627	469,627	469,627	469,627	469,627
0													
Total Gas Financials	**13,861,885**	**(2,043,321)**	**(802,780)**	**1,426,463**	**2,387,876**	**2,627,215**	**2,525,428**	**360,284**	**297,853**	**653,279**	**2,939,828**	**2,533,928**	**955,831**
Geothermal Fuel Costs													
GEO_Blundell 1	**3,170,429**	309,265	279,336	279,336	280,341	300,637	286,715	271,085	284,381	291,794	272,164	151,321	164,054
GEO_Blundell 2	**1,381,645**	147,909	133,596	133,596	130,074	120,972	104,090	107,501	107,531	117,113	126,023	70,539	82,702
Total Geothermal Fuel Costs	**4,552,074**	**457,175**	**412,932**	**412,932**	**410,415**	**421,609**	**390,805**	**378,586**	**391,912**	**408,907**	**398,186**	**221,859**	**246,757**
Total Generation Fuel Costs	**847,272,587**	**76,040,705**	**69,325,843**	**66,286,749**	**57,139,050**	**46,903,696**	**61,014,893**	**87,304,507**	**86,129,448**	**73,617,022**	**71,208,989**	**72,209,228**	**80,092,456**
NPC	**1,402,959,155**	**113,011,252**	**110,946,867**	**116,618,187**	**107,008,968**	**107,903,680**	**120,937,475**	**138,994,763**	**132,317,737**	**109,984,159**	**111,706,200**	**112,211,552**	**121,318,315**

Case No. PAC-E-24-04
Exhibit No. 25
Witness: Ramon J. Mitchell

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Ramon J. Mitchell

GRID Validation

May 2024

PacifiCorp

GRID Validation NPC Report

Net Power Cost Analysis

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	7,532,217	735,605	518,304	481,626	474,039	433,303	595,216	737,682	733,885	726,030	643,094	706,458	746,974
Hurricane Sale	7,474	623	623	623	623	623	623	623	623	623	623	623	623
Leaning Juniper Revenue	105,254	7,601	7,384	9,260	5,355	4,684	6,043	14,266	16,102	10,939	7,961	6,724	8,936
Total Long Term Firm Sales	**7,644,944**	**743,829**	**526,310**	**491,509**	**480,016**	**438,610**	**601,882**	**752,571**	**750,609**	**737,591**	**651,677**	**713,806**	**756,532**
Short Term Firm Sales													
COB	-	-	-	-	-	-	-	-	-	-	-	-	-
Colorado	-	-	-	-	-	-	-	-	-	-	-	-	-
Four Corners	21,354,660	3,522,890	2,974,080	3,095,370	1,977,600	1,958,400	1,977,600	-	-	-	1,971,460	1,905,800	1,971,460
Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-
Mead	-	-	-	-	-	-	-	-	-	-	-	-	-
Mid Columbia	-	-	-	-	-	-	-	-	-	-	-	-	-
Mona	7,750,000	1,277,800	1,202,400	1,345,800	338,000	325,000	338,000	-	-	-	985,000	953,000	985,000
NOB	-	-	-	-	-	-	-	-	-	-	-	-	-
Palo Verde	23,424,050	3,801,450	3,397,800	3,751,050	1,877,100	1,834,950	1,877,100	-	-	-	2,320,550	2,243,500	2,320,550
SP15	-	-	-	-	-	-	-	-	-	-	-	-	-
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	-	-	-	-	-	-	-	-	-	-	-	-
West Main	-	-	-	-	-	-	-	-	-	-	-	-	-
Wyoming	-	-	-	-	-	-	-	-	-	-	-	-	-
Electric Swaps Sales	-	-	-	-	-	-	-	-	-	-	-	-	-
STF Trading Margin	-	-	-	-	-	-	-	-	-	-	-	-	-
STF Index Trades	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Short Term Firm Sales	**52,528,710**	**8,602,140**	**7,574,280**	**8,192,220**	**4,192,700**	**4,118,350**	**4,192,700**	**-**	**-**	**-**	**5,277,010**	**5,102,300**	**5,277,010**
System Balancing Sales													
COB	29,651,914	3,332,735	2,357,695	1,898,661	1,035,907	1,048,019	1,760,434	2,240,054	2,231,577	2,100,152	3,520,890	3,894,654	4,231,137
Four Corners	39,704,708	3,303,662	3,448,953	2,009,392	1,765,495	1,113,323	640,820	6,174,110	5,483,323	5,864,117	3,124,169	3,104,731	3,672,614
Mead	32,132,100	4,416,682	3,016,064	1,456,847	948,624	1,219,709	1,728,477	2,297,774	3,511,400	3,195,582	3,421,497	3,562,410	3,357,034
Mid Columbia	44,001,091	3,786,533	803,610	528,753	2,209,685	1,371,110	2,444,523	6,701,841	7,389,368	7,080,796	4,269,499	4,171,327	3,244,045
Mona	19,491,384	1,825,358	547,950	233,377	784,958	995,043	1,432,010	2,289,681	2,400,963	5,463,776	1,324,799	1,133,092	1,060,377
NOB	6,320,250	-	14,777	588,915	784,080	22,523	47,501	1,252,386	1,907,945	654,601	26,842	11,956	1,008,724
Palo Verde	29,896,139	447,443	(13,689)	18,916	942,147	1,047,494	1,457,472	8,639,102	9,586,551	6,248,536	514,470	363,107	644,590
Trapped Energy	1,403	-	-	-	-	-	-	-	-	-	-	1,403	-
Total System Balancing Sales	**201,198,989**	**17,112,413**	**10,175,360**	**6,734,861**	**8,470,896**	**6,817,222**	**9,511,238**	**29,594,947**	**32,511,127**	**30,607,559**	**16,202,167**	**16,242,679**	**17,218,521**
Total Special Sales For Resale	**261,372,642**	**26,458,383**	**18,275,950**	**15,418,589**	**13,143,612**	**11,374,182**	**14,305,819**	**30,347,518**	**33,261,736**	**31,345,151**	**22,130,854**	**22,058,785**	**23,252,063**

Purchased Power & Net Interchange

Long Term Firm Purchases													
APS Supplemental	-	-	-	-	-	-	-	-	-	-	-	-	-
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	33,416,953	2,792,679	2,843,532	2,655,765	2,590,568	2,494,076	2,584,049	2,979,142	2,979,142	2,947,847	2,946,543	2,667,501	2,936,112
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
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	165,480	13,790	13,790	13,790	13,790	13,790	13,790	13,790	13,790	13,790	13,790	13,790	13,790
MagCorp	-	-	-	-	-	-	-	-	-	-	-	-	-
MagCorp Reserves	4,828,040	401,000	392,980	401,000	409,020	401,000	409,020	413,030	392,980	388,970	372,930	433,080	413,030
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	860,113	27,048	47,956	54,277	82,521	102,914	122,994	114,920	97,817	85,923	61,501	35,152	27,089
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	2,693,193	112,247	140,376	230,428	259,149	310,804	322,999	305,697	292,254	260,260	214,705	137,146	107,129
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	8,293,074	822,678	726,727	767,161	706,202	682,900	572,444	516,493	545,404	595,645	725,353	782,463	849,605
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
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	**209,204,921**	**20,224,670**	**17,206,098**	**19,037,430**	**17,490,397**	**16,441,523**	**15,849,432**	**15,598,304**	**15,248,923**	**15,998,428**	**17,943,153**	**18,484,599**	**19,681,966**

Qualifying Facilities													
QF California	2,467,000	216,317	237,210	267,860	313,293	303,385	244,839	166,844	139,023	130,932	134,351	138,704	174,243
QF Idaho	7,830,524	586,487	540,373	616,487	662,125	778,621	784,464	785,940	597,914	591,427	566,801	625,791	694,093
QF Oregon	50,845,304	2,958,588	3,117,888	4,078,136	5,046,106	5,478,394	5,705,557	5,559,591	5,255,566	4,563,767	3,597,862	2,672,224	2,811,626
QF Utah	11,512,240	791,583	826,865	990,034	1,020,610	1,117,447	1,135,413	1,059,082	1,055,762	992,673	936,615	829,151	757,005
QF Washington	218,736	-	-	19	8,001	21,996	37,135	51,373	52,945	35,398	11,871	-	-
QF Wyoming	86,184	10,091	8,471	10,115	6,257	4,967	2,992	8,382	7,360	4,207	5,944	6,878	10,520
Biomass One QF	15,273,904	1,240,648	1,202,763	1,328,736	1,605,813	1,011,582	995,142	1,455,970	1,407,489	1,392,627	1,454,930	1,426,922	751,283
Chevron Wind QF	-	-	-	-	-	-	-	-	-	-	-	-	-
DCFP QF	117,193	3,577	4,372	3,513	2,866	3,059	4,880	19,721	22,137	26,416	12,083	7,259	7,310
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
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
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	10,639,652	1,303,917	924,899	1,187,446	905,027	704,142	650,577	649,784	680,906	450,438	820,675	1,263,591	1,098,250
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	982,170	43,523	50,277	26,541	102,556	104,709	88,024	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	30,170,399	2,309,028	2,161,795	2,472,700	2,027,444	2,723,249	2,736,541	2,752,683	2,722,145	2,586,845	2,374,035	2,757,466	2,546,468
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	298,022	46,182	34,259	27,485	19,215	25,768	7,053	13,571	21,290	19,336	20,203	20,155	43,505
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	**334,755,618**	**22,829,307**	**24,055,015**	**28,265,079**	**30,160,014**	**30,292,609**	**31,842,323**	**34,099,488**	**32,605,910**	**28,631,195**	**25,787,141**	**23,917,202**	**22,270,336**
Mid-Columbia Contracts													
Grant Reasonable	-	-	-	-	-	-	-	-	-	-	-	-	-
Grant Meaningful Priority	25,591,630	2,132,636	2,132,636	2,132,636	2,132,636	2,132,636	2,132,636	2,132,636	2,132,636	2,132,636	2,132,636	2,132,636	2,132,636
Grant Surplus	2,072,011	172,668	172,668	172,668	172,668	172,668	172,668	172,668	172,668	172,668	172,668	172,668	172,668
Grant - Priest Rapids	-	-	-	-	-	-	-	-	-	-	-	-	-
Mid-Columbia Contracts Total	**27,663,641**	**2,305,303**	**2,305,303**	**2,305,303**	**2,305,303**	**2,305,303**	**2,305,303**	**2,305,303**	**2,305,303**	**2,305,303**	**2,305,303**	**2,305,303**	**2,305,303**
Total Long Term Firm Purchases	**571,624,179**	**45,359,280**	**43,566,416**	**49,607,813**	**49,955,714**	**49,039,435**	**49,997,058**	**52,003,095**	**50,160,136**	**46,934,926**	**46,035,597**	**44,707,103**	**44,257,606**

Storage & Exchange													
APS Exchange	-	-	-	-	-	-	-	-	-	-	-	-	-
Black Hills CTs	-	-	-	-	-	-	-	-	-	-	-	-	-
Cowlitz Swift	-	-	-	-	-	-	-	-	-	-	-	-	-
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
SCL State Line	-	-	-	-	-	-	-	-	-	-	-	-	-
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	14,768,640	1,621,000	1,556,160	1,750,680	-	-	1,216,800	2,912,000	2,912,000	2,800,000	-	-	-
Mona	-	-	-	-	-	-	-	-	-	-	-	-	-
NOB	-	-	-	-	-	-	-	-	-	-	-	-	-
Palo Verde	678,500	247,250	207,000	224,250	-	-	-	-	-	-	-	-	-
SP15	-	-	-	-	-	-	-	-	-	-	-	-	-
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	-	-	-	-	-	-	-	-	-	-	-	-
West Main	-	-	-	-	-	-	-	-	-	-	-	-	-
Wyoming	-	-	-	-	-	-	-	-	-	-	-	-	-
STF purchase subtotal	**15,447,140**	**1,868,250**	**1,763,160**	**1,974,930**	**-**	**-**	**1,216,800**	**2,912,000**	**2,912,000**	**2,800,000**	**-**	**-**	**-**
STF Electric Swaps	-	-	-	-	-	-	-	-	-	-	-	-	-
STF Index Trades	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Short Term Firm Purchases	**15,447,140**	**1,868,250**	**1,763,160**	**1,974,930**	**-**	**-**	**1,216,800**	**2,912,000**	**2,912,000**	**2,800,000**	**-**	**-**	**-**
System Balancing Purchases													
COB	14,400,284	285,501	1,261,483	1,663,711	654,627	1,723,681	1,485,126	2,446,485	1,421,069	490,529	859,093	269,382	1,839,598
Four Corners	28,429,398	2,842,587	6,364,713	5,884,089	1,787,296	1,633,184	309,859	982,553	851,816	639,118	1,206,644	1,623,407	4,304,131
Mead	6,543,189	387,353	928,141	318,456	278,541	379,237	379,454	940,549	439,285	462,393	719,567	378,270	931,941
Mid Columbia	74,407,799	3,915,594	800,844	526,045	1,576,329	12,539,935	10,932,812	16,028,724	15,750,997	4,701,338	2,559,815	2,096,022	2,979,345
Mona	8,713,073	947,711	193,196	1,362,896	221,788	747,258	66,919	835,818	503,604	356,076	1,169,571	1,267,020	1,041,216
NOB	13,555,306	-	54,296	839,002	1,593,155	47,602	126,782	2,608,241	4,164,455	1,515,362	44,561	30,185	2,531,664
Palo Verde	3,291,208	1,912,292	661,767	450,253	9,223	39,536	-	-	2,543	8,368	40,836	155,432	10,958
EIM Imports/Exports	(59,250,810)	(3,445,870)	(3,105,010)	(6,863,178)	(6,863,641)	(7,467,599)	(3,035,622)	(7,434,719)	(7,740,230)	(4,243,730)	(2,826,239)	(2,722,603)	(3,502,369)
Emergency Purchases	1,904,827	-	-	-	59,287	773,282	72,269	451,177	44,688	354,008	67,468	16,629	66,017
Total System Balancing Purchases	**91,994,275**	**6,845,168**	**7,159,431**	**4,181,275**	**(683,394)**	**10,416,116**	**10,337,600**	**16,858,829**	**15,438,227**	**4,283,462**	**3,841,317**	**3,113,745**	**10,202,500**
Total Purchased Power & Net Inter	**684,465,594**	**54,522,699**	**52,939,007**	**56,214,017**	**49,722,320**	**59,905,551**	**62,001,457**	**72,223,924**	**68,960,363**	**54,468,388**	**50,326,914**	**48,270,848**	**54,910,106**

Wheeling & U. of F. Expense													
Firm Wheeling	138,233,270	11,846,758	11,639,521	11,941,445	11,705,073	10,378,573	11,220,154	10,774,214	10,929,786	11,622,523	11,445,797	12,073,700	12,655,725
C&T EIM Admin fee	2,038,227	184,546	167,911	161,471	204,085	222,363	208,177	172,436	135,045	153,613	170,764	127,508	130,308
ST Firm & Non-Firm	43,029	13,235	3,760	3,011	434	-	1,277	4,049	2,190	1,585	2,870	7,203	3,415
Total Wheeling & U. of F. Expense	**140,314,526**	**12,044,539**	**11,811,193**	**12,105,927**	**11,909,592**	**10,600,936**	**11,429,608**	**10,950,699**	**11,067,022**	**11,777,721**	**11,619,431**	**12,208,412**	**12,789,447**
Coal Fuel Burn Expense													
Cholla	-	-	-	-	-	-	-	-	-	-	-	-	-
Colstrip	15,944,066	1,758,488	1,502,306	1,491,743	1,294,454	719,529	1,130,158	1,544,746	1,651,646	1,436,935	951,206	1,010,123	1,452,732
Craig	19,150,970	1,915,459	1,662,106	1,728,134	1,467,240	701,480	1,373,402	1,586,878	1,847,263	1,720,488	1,695,960	1,624,924	1,827,637
Dave Johnston	55,761,755	5,545,315	5,097,111	4,666,077	3,972,961	4,406,396	4,179,117	4,600,831	5,049,983	4,544,176	5,008,160	3,899,963	4,791,664
Hayden	11,314,790	1,092,517	971,852	996,901	891,991	1,119,222	980,957	1,054,345	890,611	583,886	745,023	962,052	1,025,432
Hunter	119,361,523	11,752,962	9,868,586	8,782,962	6,001,455	7,541,139	9,746,152	11,280,364	11,214,492	10,620,817	10,346,073	11,107,035	11,099,486
Huntington	99,922,532	9,902,243	8,280,046	7,685,095	7,137,019	5,729,828	6,704,581	10,577,674	10,714,065	7,672,838	6,652,417	8,067,526	10,799,200
Jim Bridger	160,568,885	10,891,597	11,572,897	12,951,734	11,209,268	8,629,348	10,713,340	21,122,415	20,810,479	14,798,137	11,635,424	13,336,149	12,898,097
Naughton	75,457,447	7,037,257	6,059,344	6,209,946	5,907,535	4,795,131	5,900,533	6,659,412	6,855,070	6,691,583	6,915,264	6,264,483	6,161,889
Wyodak	29,019,449	2,571,408	2,513,652	2,811,880	2,503,324	2,778,487	2,190,116	2,725,396	2,562,642	2,392,560	2,402,957	2,007,981	1,559,048
Total Coal Fuel Burn Expense	**586,501,418**	**52,467,246**	**47,527,899**	**47,324,471**	**40,385,246**	**36,420,561**	**42,918,356**	**61,152,062**	**61,596,250**	**50,461,421**	**46,352,485**	**48,280,236**	**51,615,184**
Gas Fuel Burn Expense													
Chehalis	38,103,671	2,474,830	1,122,065	1,924,565	2,320,703	20,136	1,745,829	4,774,064	4,709,339	4,661,488	5,007,935	4,525,362	4,817,356
Currant Creek	36,936,636	2,483,854	453,011	132,129	2,689,159	1,529,496	3,400,255	4,743,362	3,618,956	3,968,192	4,557,262	4,945,180	4,415,780
Gadsby	5,491,715	35,942	50,150	123,858	150,209	174,358	456,732	1,067,946	1,075,590	711,177	409,440	460,218	776,095
Gadsby CT	2,787,073	29,777	3,274	5,485	72,169	69,796	139,815	522,811	511,036	277,374	230,875	235,501	689,160
Hermiston	22,167,592	2,345,965	1,350,019	1,282,104	1,844,660	8,533	869,383	2,327,739	2,463,347	2,398,513	2,294,975	2,401,167	2,581,189
Lake Side 1	54,900,622	5,103,037	3,688,461	2,687,692	4,180,292	2,382,044	4,198,764	5,870,751	5,853,992	5,353,046	4,549,555	5,320,139	5,712,850
Lake Side 2	63,220,546	6,524,249	4,749,373	3,899,626	4,119,433	3,713,927	4,787,196	5,935,265	5,954,663	5,608,375	5,437,945	5,486,567	7,003,926
Naughton - Gas	20,317,381	2,531,859	2,433,992	1,963,691	593,083	1,074,098	1,226,797	1,988,607	1,826,395	1,191,663	1,313,676	1,403,712	2,769,808
Total Gas Fuel Burn	243,925,235	21,529,514	13,850,343	12,019,150	15,969,706	8,972,388	16,824,770	27,230,545	26,013,318	24,169,828	23,801,662	24,777,847	28,766,164
Gas Physical	(416,723)	(79,114)	(57,965)	(24,301)	(25,945)	(23,006)	(23,393)	(50,730)	(49,843)	(45,141)	(37,288)	-	-
Gas Swaps	(19,937,668)	(4,536,928)	(3,311,210)	(1,238,993)	(534,300)	(308,760)	(399,300)	(2,547,968)	(2,611,285)	(2,249,700)	18,135	(364,800)	(1,852,560)
Clay Basin Gas Storage	(588,564)	(334,019)	(307,763)	(216,982)	52,242	52,242	52,242	52,242	52,242	52,242	52,242	2,850	(98,348)
Pipeline Reservation Fees	36,238,771	3,006,087	2,970,650	3,003,231	3,001,490	3,013,815	3,016,829	3,053,890	3,053,707	3,026,691	3,028,291	3,019,210	3,044,880
Total Gas Fuel Burn Expense	**259,221,051**	**19,585,541**	**13,144,055**	**13,542,105**	**18,463,195**	**11,706,680**	**19,471,149**	**27,737,980**	**26,458,139**	**24,953,920**	**26,863,043**	**27,435,107**	**29,860,136**
Other Generation													
Blundell	4,501,334	457,175	412,932	412,932	402,228	418,278	386,442	365,375	383,296	405,974	390,495	223,692	242,515
Blundell Bottoming Cycle	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Other Generation	**4,501,334**	**457,175**	**412,932**	**412,932**	**402,228**	**418,278**	**386,442**	**365,375**	**383,296**	**405,974**	**390,495**	**223,692**	**242,515**
Net Power Cost	**1,413,631,280**	**112,618,817**	**107,559,136**	**114,180,864**	**107,738,968**	**107,677,824**	**121,901,193**	**142,082,522**	**135,203,334**	**110,722,273**	**113,421,514**	**114,359,509**	**126,165,326**

REDACTED
Case No. PAC-E-24-04
Exhibit No. 26
Witness: Ramon J. Mitchell

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

ROCKY MOUNTAIN POWER

REDACTED
Exhibit Accompanying Direct Testimony of Ramon J. Mitchell

Aurora Benchmark

May 2024

Results of the Aurora Benchmarking Study

The results of the benchmarking study show that Aurora simulated 2020 historical net power costs (NPC) at $58.7 million less than actual NPC. Aurora estimated total company 2020 NPC to be $1,453 million compared to actual 2020 costs of $1,511 million, an under-forecast of 3.9 percent.

Confidential Table 1 illustrates a detailed comparison between the benchmarking study and 2020 Actual NPC. Long-term firm sales and long-term firm purchase dollars and megawatt-hours (MWh) are based on actual transactions. Hydroelectric generation and solar generation are based on actual generation. The variance between short-term firm and system balancing sales and purchases is driven by the fact that Aurora balances the system differently than the Company does in actual operations. More specifically, Aurora faces a different set of operational constraints compared to what the Company faces in real time. For example, market liquidity in the benchmarking study is predetermined based on market capacity limits that allow more sales transactions than the Company's historical experience.

It is important to note that the NPC forecast is designed with hourly average inputs. Given a certain set of hourly average input variables, Aurora applies its system balancing logic to meet load and wholesale obligations under the operational constraints assumed in the model. In actual operations, the Company faces a different set of real (moment-to-moment) system constraints, many of which are not able to be fully reflected in Aurora's modeling assumptions. Furthermore, Aurora is not able to forecast thermal dispatch in the same way that PacifiCorp dispatches its thermal plants in real time and Aurora's optimization of the system is perfect which means that after the optimization is complete no net savings can be further achieved by backing down one unit and ramping up another unit.

In actual operations, as a matter of prudence, PacifiCorp seeks to optimize the system. However, in reality, PacifiCorp faces a different set of constraints resulting from actual market conditions, and in real time, system dispatch will choose to balance the system using coal plants, gas plants and system balancing purchases and sales in an order that is feasible to current market conditions. The order of selection of coal plants, gas plants and system balancing purchase and sales results in differences in each resource category compared to the benchmarking study results. Consequently, and as shown in **Confidential Table 1** below, the coal and natural gas dispatch (on a MWh basis) in Aurora was approximately one percent more and two percent less than actuals, respectively.

Confidential Table 1 – Net Power Cost Differential Summary – Benchmark

[CONFIDENTIAL BEGINS]

Net Power Cost Differential Summary

Benchmark

	Aurora	Actual	Difference	Difference %
[redacted]				

	Aurora	Actual	Difference	Difference %
[redacted]				

[CONFIDENTIAL ENDS]

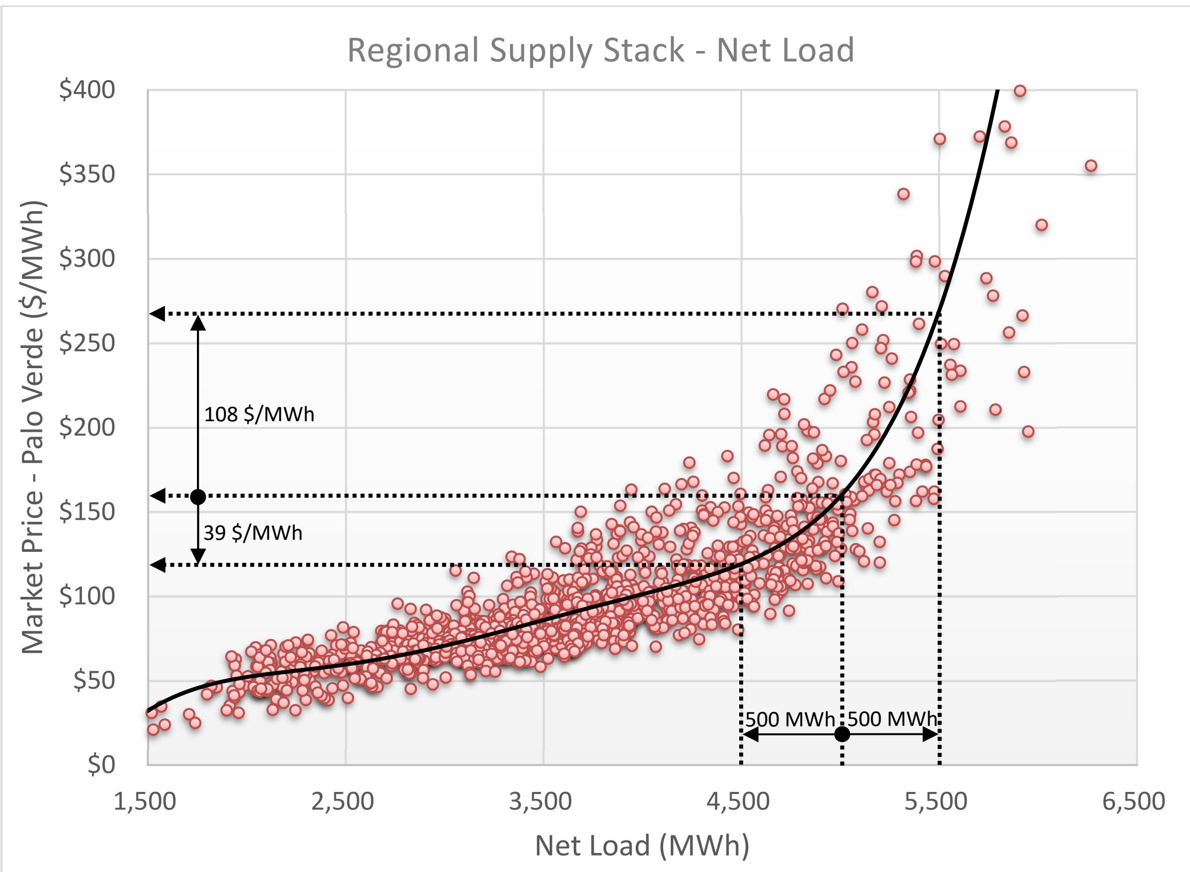
Conclusions

When actual data is used as inputs, Aurora produces 2020 NPC below the actual 2020 NPC and this is to be expected.

First, Aurora applies its system balancing logic with perfect foresight and perfect execution. That is to say, Aurora knows the future and operates the system with perfect efficiency in every hour. In reality, the future is uncertain, humans cannot know exactly at what level variable resources will be producing in a future hour and there will always be some inefficiency within a grouping of individuals (people). In the context of NPC, this reality of the human experience deviates from the perfection inherent in Aurora and the associated perfectly-low Aurora NPC.

Second, there is an asymmetry in the response of market prices to changes in load and generation. As an illustrative example, **Figure 1** below shows a proxy supply/demand curve (with inelastic demand) based on actual load, wind, and solar data within the region. It is observed that because of the asymmetry of market price response, a 500 MWh increase in net load (load less wind less solar) results in a $108 dollar per MWh ($/MWh) increase in market price, whereas an identical 500 MWh decrease in net load results in only a $39/MWh decrease to market price.

Figure 1



This asymmetrical response impacts actual operations because the net load forecasts, in reality, are uncertain (i.e., there is no perfect foresight). This uncertainty results in an equal chance of net load being higher or lower than forecasted. However, the impact to NPC is an asymmetric response wherein the actual NPC has a greater chance of being higher than the forecast NPC and consequently the forecast NPC is biased downwards relative to the actual NPC. This result is observed in this benchmarking study.

Case No. PAC-E-24-04
Exhibit No. 27
Witness: Ramon J. Mitchell

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Ramon J. Mitchell

General Electric Company – Effect of Temperature on Output

May 2024

General Electric Model 7F.04 Gas Turbine

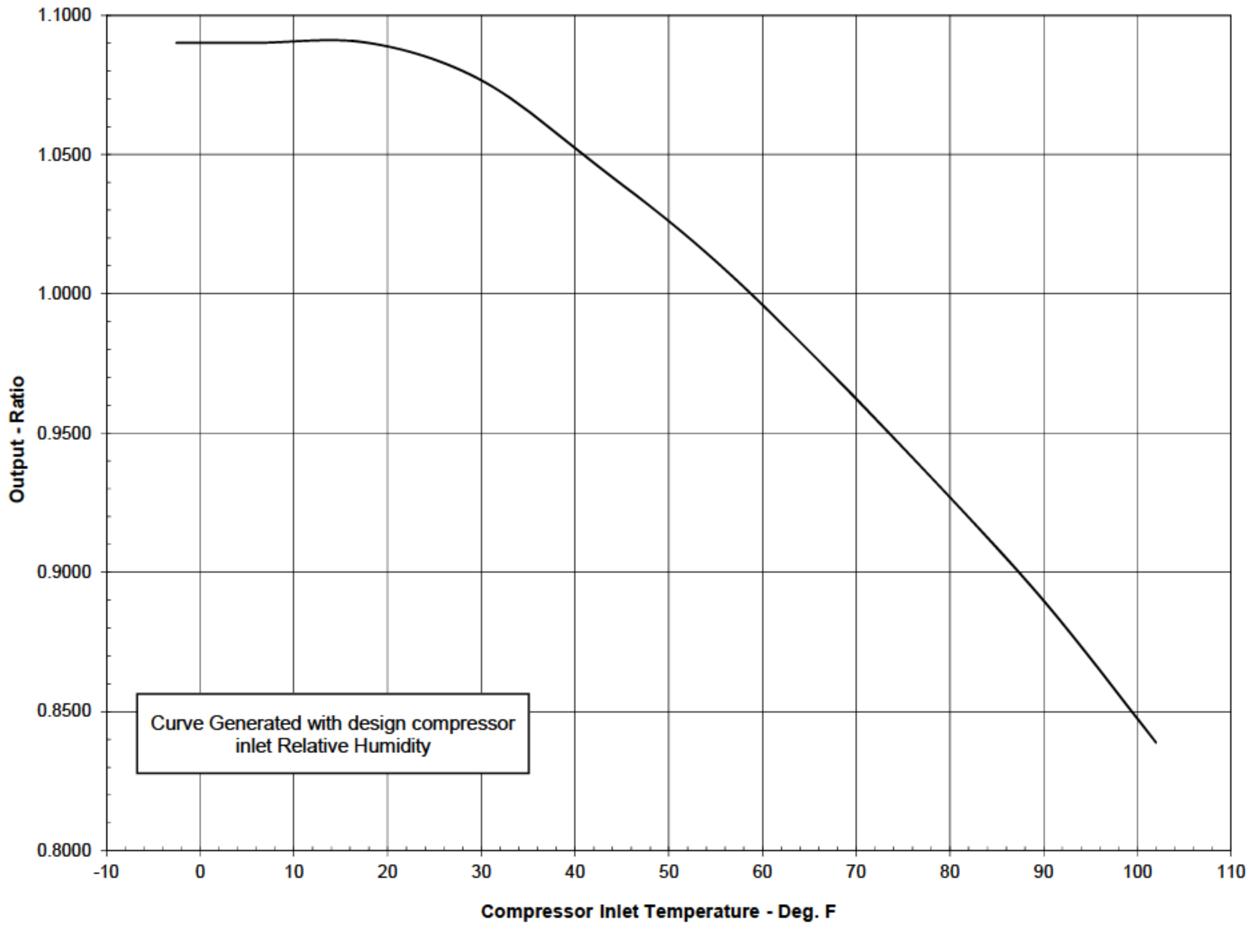
[redacted]

Estimated Performance

Effect of Compressor Inlet Temperature on Output

Design Values Referenced on 104H6508 Rev - Sheet 1
Fuel: Gas
Mode: Base

[redacted]



	Units										
Compressor Inlet Temperature	F	-2.55	6.00	18.00	30.00	42.00	54.00	66.00	78.00	90.00	102.00
Output Ratio		1.09008	1.09008	1.09008	1.07666	1.04701	1.01476	0.97597	0.93401	0.88979	0.83877

[redacted]

104H6508 Rev -
Sheet 3

Case No. PAC-E-24-04
Exhibit No. 28
Witness: Ramon J. Mitchell

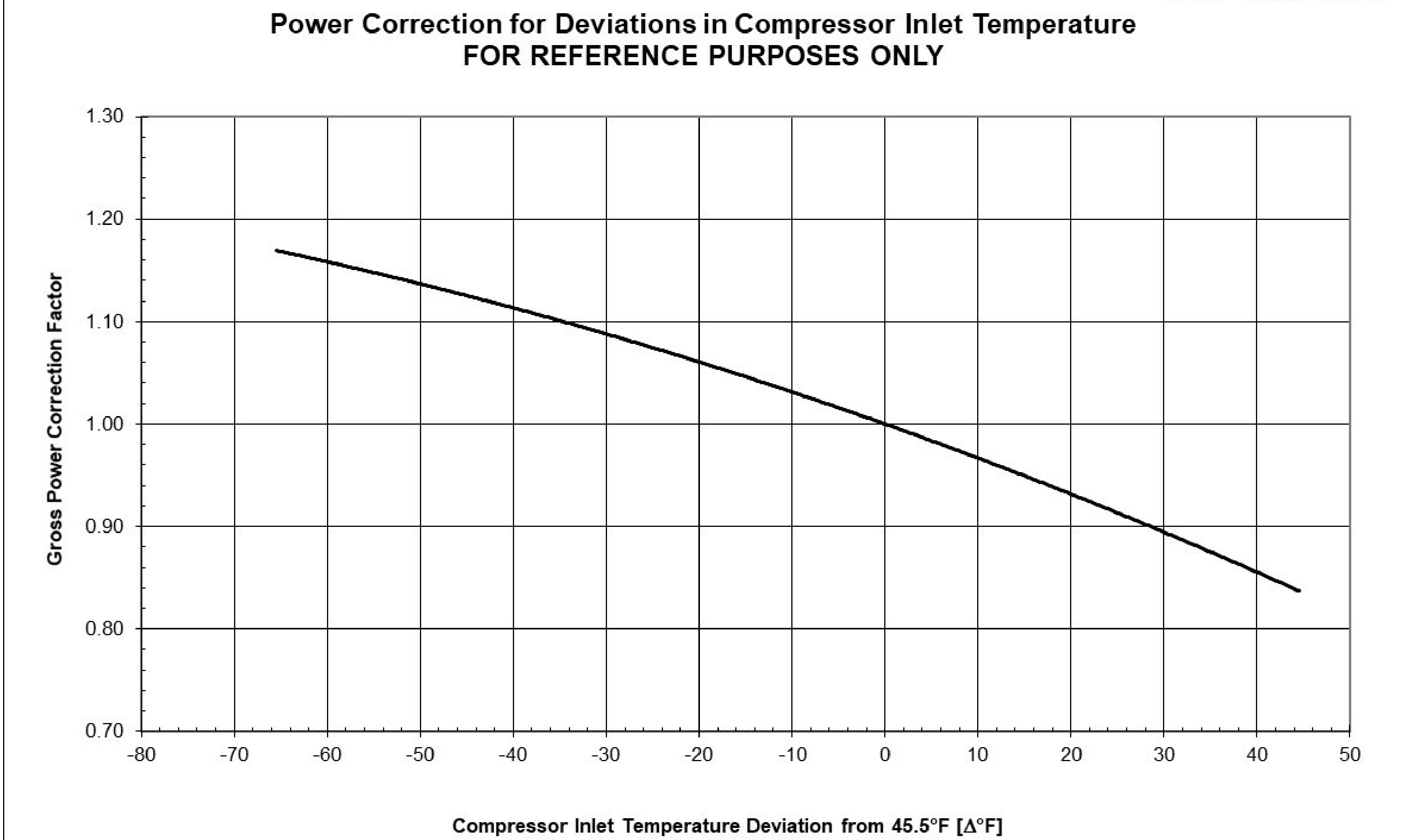
BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Ramon J. Mitchell

Siemens Energy AG – Effect of Temperature on Output

May 2024


Power Correction for Deviations in Compressor Inlet Temperature
FOR REFERENCE PURPOSES ONLY
Gross Power Correction Factor
1.30
1.20
1.10
1.00
0.90
0.80
0.70
-80
-70
-60
-50
-40
-30
-20
-10
0
10
20
30
40
50
Compressor Inlet Temperature Deviation from 45.5°F [Δ°F]