PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
Portland, Oregon 97232

March 1, 2022

VIA ELECTRONIC FILING

Public Utility Commission of Oregon
Attn: Filing Center
201 High Street SE, Suite 100
Salem, OR 97301-3398

Re: Advice No. 22-003/UE 400—PacifiCorp's 2023 Transition Adjustment Mechanism

In compliance with ORS 757.205, OAR 860-022-0025, and OAR 860-022-0030, PacifiCorp d/b/a Pacific Power (PacifiCorp) submits for filing the following proposed tariff pages associated with Tariff P.U.C. OR No. 36, which sets forth all rates, tolls, charges, rules, and regulations applicable to electric service in Oregon. PacifiCorp requests an effective date of January 1, 2023.

A. Description of Filing

The purpose of the Transition Adjustment Mechanism (TAM) is to update net power costs for 2023 and to set transition credits for Oregon customers who choose direct access in the November open enrollment window. The following proposed tariff sheets are provided in Ms. Judith M. Ridenour's Exhibit PAC/402. This tariff filing is supported by testimony and exhibits from the following witnesses:

- Michael G. Wilding, Vice President, Energy Supply Management
- James Owen, Senior Vice President, Environmental, Fuels, and Mining
- Daniel J. MacNeil, Commercial Analytics Advisor
- Judith M. Ridenour, Specialist, Pricing and Cost of Service

B. Tariff Sheets

Sheet	Schedule	Title
Seventeenth Revision of Sheet No. 201-1	Schedule 201	Net Power Costs – Cost-Based Supply Service
Seventeenth Revision of Sheet No. 201-2	Schedule 201	Net Power Costs – Cost-Based Supply Service
Seventeenth Revision of Sheet No. 201-3	Schedule 201	Net Power Costs – Cost-Based Supply Service

PacifiCorp will file changes to the transition adjustment tariffs—Schedules 294, 295, and 296—along with any needed changes to Schedule 293 – New Large Load Direct Access Program and Schedule 220 – Standard Daily Offer once the final TAM rates have been posted and are known. The final TAM rates will be established in November, just before the open enrollment window.

C. Requirements of OAR 860-022-0025 and OAR 860-022-0030

To support the proposed rates and meet the requirements of OAR 860-022-0025 and OAR 860-022-0030, PacifiCorp provides the description and support indicated in Section A above. Please refer to the exhibits of Ms. Ridenour for the calculation of the proposed rate changes and impacts of proposed price changes by rate schedule.

This proposed change will affect approximately 646,000 customers and would result in an overall annual rate increase of approximately $70 million, or 5.6 percent. Residential customers using 900 kilowatt-hours per month would see an average monthly bill increase of $7.16 per month as a result of this change.

D. Correspondence

PacifiCorp respectfully requests that all communications related to this filing be addressed to:

Oregon Dockets
PacifiCorp
825 NE Multnomah Street, Suite 2000
Portland, OR 97232
oregondockets@pacificorp.com

Ajay Kumar
Senior Attorney
825 NE Multnomah Street, Suite 2000
Portland, OR 97232
ajay.kumar@pacificorp.com

Additionally, PacifiCorp requests that all data requests regarding this matter be addressed to:

By e-mail (preferred): datarequest@pacificorp.com

By regular mail: Data Request Response Center
PacifiCorp
825 NE Multnomah Street, Suite 2000
Portland, OR 97232

Please direct informal correspondence and questions regarding this filing to Cathie Allen at (503) 813-5934.

A copy of this filing has been served on all parties to PacifiCorp's 2021 TAM proceeding, docket UE 390. Confidential material in support of the filing has been provided to parties under Order No. 16-128.

Sincerely,

Shelley McCoy

Shelley McCoy
Director, Regulation

Enclosures

cc: UE 390 Service List
UE 400 Service List

CERTIFICATE OF SERVICE

I certify that I delivered a true and correct copy of PacifiCorp's **2023 Transition Adjustment Mechanism** on the parties listed below via electronic mail in compliance with OAR 860-001-0180.

Service List
UE 400

PACIFICORP	
PACIFICORP, DBA PACIFIC POWER 825 NE MULTNOMAH ST, STE 2000 PORTLAND, OR 97232 oregondockets@pacificorp.com	AJAY KUMAR **(C)** **(HC)** PACIFICORP 825 NE MULTNOMAH ST STE 2000 PORTLAND, OR 97232 ajay.kumar@pacificorp.com
STAFF	
MOYA ENRIGHT **(C)** **(HC)** PUBLIC UTILITY COMMISSION OF OREGON PO BOX 1088 SALEM OR 97308 moya.enright@state.or.us	SOMMER MOSER **(C)** **(HC)** PUC STAFF - DEPARTMENT OF JUSTICE 1162 COURT ST NE SALEM, OR 97301 sommer.moser@doj.state.or.us

Dated this 1st day of March, 2022.

Mary Penfield
Adviser, Regulatory Operations

CERTIFICATE OF SERVICE

I certify that I delivered a true and correct copy of PacifiCorp's **2023 Transition Adjustment Mechanism** on the parties listed below via electronic mail in compliance with OAR 860-001-0180.

Service List
UE 390

AWEC	
TYLER C PEPPLE **(C)** **(HC)** DAVISON VAN CLEVE, PC 1750 SW HARBOR WAY STE 450 PORTLAND OR 97201 tcp@dvclaw.com	BRENT COLEMAN **(C)** **(HC)** DAVISON VAN CLEVE, PC 1750 SW HARBOR WAY STE 450 PORTLAND OR 97201 blc@dvclaw.com
JESSE O GORSUCH **(C)** **(HC)** DAVISON VAN CLEVE 1750 SW HARBOR WAY STE 450 PORTLAND OR 97201 jog@dvclaw.com	
CALPINE SOLUTIONS	
GREGORY M. ADAMS **(C)** RICHARDSON ADAMS, PLLC PO BOX 7218 BOISE ID 83702 greg@richardsonadams.com	GREG BASS CALPINE ENERGY SOLUTIONS, LLC 401 WEST A ST, STE 500 SAN DIEGO CA 92101 greg.bass@calpinesolutions.com
KEVIN HIGGINS **(C)** ENERGY STRATEGIES LLC 215 STATE ST - STE 200 SALT LAKE CITY UT 84111-2322 khiggins@energystrat.com	
OREGON CITIZENS UTILITY BOARD	
OREGON CITIZENS' UTILITY BOARD 610 SW BROADWAY, STE 400 PORTLAND, OR 97205 dockets@oregoncub.org	MICHAEL GOETZ **(C)** **(HC)** OREGON CITIZENS' UTILITY BOARD 610 SW BROADWAY STE 400 PORTLAND, OR 97205 mike@oregoncub.org
ROBERT JENKS **(C)** **(HC)** OREGON CITIZENS' UTILITY BOARD 610 SW BROADWAY, STE 400 PORTLAND, OR 97205 bob@oregoncub.org	

PACIFICORP	
PACIFICORP, DBA PACIFIC POWER 825 NE MULTNOMAH ST, STE 2000 PORTLAND, OR 97232 oregondockets@pacificorp.com	AJAY KUMAR **(C)** **(HC)** PACIFICORP 825 NE MULTNOMAH ST STE 2000 PORTLAND, OR 97232 ajay.kumar@pacificorp.com
KATHERINE A MCDOWELL **(C)** MCDOWELL RACKNER & GIBSON PC 419 SW 11TH AVE., SUITE 400 PORTLAND OR 97205 katherine@mrg-law.com	
SBUA	
JAMES BIRKELUND SMALL BUSINESS UTILITY ADVOCATES 548 MARKET ST STE 11200 SAN FRANCISCO CA 94104 james@utilityadvocates.org	DIANE HENKELS **(C)** SMALL BUSINESS UTILITY ADVOCATES 621 SW MORRISON ST. STE 1025 PORTLAND OR 97205 diane@utilityadvocates.org
DARREN WERTZ **(C)** SMALL BUSINESS UTILITY ADVOCATES wertzds@gmail.com	
SIERRA CLUB	
ANA BOYD **(C)** **(HC)** SIERRA CLUB 2101 WEBSTER ST STE 1300 OAKLAND CA 94612 ana.boyd@sierraclub.org	ROSE MONAHAN **(C)** **(HC)** SIERRA CLUB 2101 WEBSTER ST STE 1300 OAKLAND CA 94612 rose.monahan@sierraclub.org
STAFF	
SCOTT GIBBENS **(C)** **(HC)** PUBLIC UTILITY COMMISSION OF OREGON 201 HIGH ST SE SALEM OR 97301 scott.gibbens@state.or.us	SOMMER MOSER **(C)** **(HC)** PUC STAFF - DEPARTMENT OF JUSTICE 1162 COURT ST NE SALEM, OR 97301 sommer.moser@doj.state.or.us
MOYA ENRIGHT **(C)** **(HC)** PUBLIC UTILITY COMMISSION OF OREGON PO BOX 1088 SALEM OR 97308 moya.enright@state.or.us	

Dated this 1st day of March, 2022.

Mary Penfield
Adviser, Regulatory Operations

REDACTED
Docket No. UE 400
Exhibit PAC/100
Witness: Michael G. Wilding

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED

Direct Testimony of Michael G. Wilding

March 2022

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ATTACHED EXHIBITS

Exhibit PAC/101—Oregon-Allocated Net Power Costs

Exhibit PAC/102—Net Power Costs Report

Confidential Exhibit PAC/103—Aurora Test NPC Report

Confidential Exhibit PAC/104—GRID Test NPC Report

Confidential Exhibit PAC/105—Aurora Overview Presentation

Confidential Exhibit PAC/106—Update to Renewable Energy Production Tax Credits

Exhibit PAC/107—Step Log Change

Exhibit PAC/108—January 28, 2022 Notice Letter

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name, business address, and present position with PacifiCorp d/b/a Pacific Power (PacifiCorp or Company).

A. My name is Michael G. Wilding and my business address is 825 NE Multnomah Street, Suite 600, Portland, Oregon 97232. My title is Vice President, Energy Supply Management.

Q. Please describe your education and professional experience.

A. I received a Master of Accounting from Weber State University and a Bachelor of Science degree in accounting from Utah State University. As Vice President, Energy Supply Management (ESM), my responsibilities include directing PacifiCorp's front office organization in commercial and trading activities. ESM is responsible for commercially managing PacifiCorp's diverse generation portfolio. This includes the electric and natural gas hedging, term and day-ahead trading, real-time trading and system balancing. I also oversee the Company's regulatory net power cost (NPC) filings and its environmental reporting. Prior to assuming my current position in February 2021, I worked on various regulatory projects including general rate cases, the multi-state process (MSP), and NPC filings. I have been employed by PacifiCorp since 2014.

Q. Have you testified in previous regulatory proceedings?

A. Yes. I have previously provided testimony to the Public Utility Commission of Oregon (Commission) as well as commissions in California, Utah, Washington, and Wyoming.

II. PURPOSE OF TESTIMONY

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

A. I present the Company's proposed 2023 Transition Adjustment Mechanism (TAM) NPC. Specifically, my testimony:

- Summarizes the content of the filing;
- Defines NPC and describes the NPC change in the 2023 TAM compared to the final NPC in docket UE 390, the 2022 TAM;
- Describes the major cost drivers in the 2022 TAM;
- Discusses the transition to the Aurora model, the implementation of the nodal pricing model (NPM), and the NPM fee paid to CAISO;
- Describes modeling changes the Company is proposing in this TAM filing;
- Provides an update on a number of provisions from the 2021 TAM;
- Provides specific information requested by the Commission on Production Tax Credits (PTCs) and NPC benefits of PacifiCorp's wind projects;
- Discusses the information requested by the Commission in the last TAM Order;
- Provides details on the calculation of the Company Supply Service Access Charge applicable to PacifiCorp's new load direct access program for consumers who choose new load direct access and then subsequently choose standard offer or cost-based service.

Q. Please identify the other PacifiCorp witnesses supporting the 2023 TAM.

A. Three additional Company witnesses provide testimony supporting the Company's filing. Mr. James Owen, Vice President, Environmental, Fuels and Mining, provides testimony supporting the coal fuel costs and the prudence of the new coal agreements included in the 2023 TAM. Mr. Daniel J. MacNeil, Commercial Analytics Adviser, provides testimony supporting PacifiCorp's modeling adjustment on the regulating reserve requirement. Ms. Judith M. Ridenour, Regulatory Specialist, Pricing & Cost of Service, presents the Company's proposed prices and tariffs and provides a comparison of existing and estimated customer rates.

III. SUMMARY OF PACIFICORP'S 2023 TAM FILING

Q. Please provide background on PacifiCorp's 2023 TAM filing.

A. The TAM is PacifiCorp's annual filing to update its NPC in rates and to set the transition adjustments for direct access customers. Along with the forecast NPC, the 2023 TAM also includes test period forecasts for: (1) incremental benefits and costs related to the Company's participation in the energy imbalance market (EIM) with the California Independent System Operator Corporation (CAISO); and (2) renewable energy PTCs.

Q. What is the total-company NPC in the TAM for calendar year 2023?

A. The forecasted normalized total-company NPC for calendar year 2023 is approximately $1.684 billion.[1] This is approximately $314 million higher than the forecast NPC of approximately $1.369 billion in the 2022 TAM. Details of total-company NPC for 2023 are provided in Exhibit PAC/102.

Q. Is $1.684 billion a reasonable forecast for total company NPC?

A. Yes. When compared to the historical NPC since 2014, it is clear that the 2023 TAM provides a reasonable forecast, especially given the current market conditions. The 2023 TAM uses the December 2021 official forward price curve (OFPC), and the

[1] Exhibit PAC/101, Wilding/1, line 35.

average Mid-Columbia heavy-load hour (HLH) energy price is $61.10/megawatt-hour (MWh) for 2023. The 2023 average Palo Verde HLH energy price is $80.06/MWh and the average natural gas price for 2023 is $3.36/one million British thermal units. Typically speaking when energy and natural gas market prices increase it would be expected that PacifiCorp's NPC would also increase. This is because PacifiCorp, through its integrated resource plan (IRP), has determined the lowest cost, risk adjusted resource plan is to have some reliance on market purchases to serve its load. This is seen in the IRP as front-office transactions, which is an open position that the company must fill in the near-term, most likely with market purchases. Therefore, when market prices rise it is logical to conclude that NPC will also most likely rise as PacifiCorp must make purchases in the market to serve its load. The Company does proactively manage its exposure to market prices with its robust hedging policy for energy and natural gas. Additionally, there are offsets to NPC when market prices rise, such as larger revenues from off-system wholesale sales and EIM transfers.

The table below shows how the 2023 TAM compares to the historical total-company NPC.

Confidential Table 1: Actual Net Power Costs 2014-2021

Year	Total Company NPC ($)	Average Purchased Power Price ($/MWh)	Average Wholesale Sales Price ($/MWh)	Average Natural Gas Generation Cost ($/MWh)	EIM Benefits (*$millions*)
2014	1,607,491,661	59.66	34.80	37.72	4.73
2015	1,535,886,048	49.66	30.31	30.22	26.22
2016	1,465,887,270	43.61	26.51	26.00	45.47
2017	1,529,959,607	43.90	29.62	29.07	37.41
2018	1,592,124,916	43.85	29.97	22.97	61.68
2019	1,660,495,378	53.31	34.89	23.79	59.77
2020	1,511,314,189	45.31	34.79	21.85	40.63
2021[2]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2022 TAM	1,369,400,716	53.86	68.78	31.55	[redacted]
2023 TAM	1,683,929,925	54.60	54.89	27.87	[redacted]

The forecast average purchased power cost in the 2023 TAM is higher than all but two of the historical years and the average cost of natural gas generation is higher than all but three of the historical years. It is worth mentioning that the three historical years with the highest NPC also have the highest average purchased power price. Notably the average wholesale sales price for energy in the 2023 TAM is higher than all the historical years and is only behind the 2022 TAM. I will address the forecast of wholesale sales later in my testimony, but this is an indication that production cost models used in the forecast are able to cherry-pick high-priced hours during which to make off-system sales where that same opportunity does not exist during actual operations. High-priced periods typically correspond with times the Company is a buyer in the market.

[2] Note: 2021 actual numbers are preliminary and have not been finalized.

Q. The 2023 TAM indicates a $314 million increase in NPC, on a total-company basis, from the 2022 TAM. Please elaborate on the drivers for this increase.

A. A primary driver of the increase is the fact that the Oregon-estimated NPC estimated in the 2022 TAM was likely too low when compared with historical data on actual NPC. Looking at Table 1 above, the 2022 TAM appears to be an outlier as it is nearly $100 million below the lowest historical NPC and approximately $140 million below the second lowest historical NPC. Consequently, I expect the 2022 TAM to result in an under-recovery of NPC.

While there are multiple factors that caused the 2022 TAM to be so low, there are three worth mentioning here. First, during the pendency of the 2022 TAM the energy and natural gas prices increased significantly. As market prices increase the Company is able to realize greater revenues from its EIM transfers and customers benefit from larger EIM benefits. Between the July Update and the Final 2022 TAM, the EIM benefits forecast nearly doubled and the Company included [redacted] EIM benefits in the 2022 TAM. Because EIM benefits act as an offset to NPC, this caused a significant reduction in the NPC forecast and customers appropriately benefited from this update. However, as these benefits are passed on to customers it is important that any costs associated with participating in the EIM are also included in the TAM. Thus, it is important that the TAM include the correct amount of regulation reserve requirements. As explained in the testimony of Mr. MacNeil, the regulation reserve requirements include the diversity benefit from EIM but ensures that the regulation reserve requirement for any single hour is not less than the minimum EIM flexible reserve requirements.

Second, as more variable energy resources (VERs) like wind and solar are added to the system, capturing all the costs associated with these resources becomes more difficult. This is because these resources are modeled as though they have a firm energy delivery schedule when in fact these resources are variable or intermittent. The variability creates uncertainty for which there is an associated cost. This is another reason it is important that the correct amount of regulation reserve requirements is included in the TAM. As discussed in the testimony of Mr. MacNeil, the regulation reserve requirements vary based on the hourly wind and solar generation values.

Finally, in the 2022 TAM the model was able to optimize off-system sales during high-priced hours driving down the NPC forecast. Notably, between the July Update and the Final 2022 TAM, with relaxed market caps, system balancing sales volumes increased by more than one million MWh. Also, in response to the increased energy and natural gas market prices, market purchases and natural gas generation both decreased in the Final 2022 TAM. To backfill the decreased market purchases and natural gas generation and to facilitate the increase in system balancing sales, coal generation increased more than four million MWh. As part of the 2023 TAM, PacifiCorp is proposing to implement market caps that will result in a more accurate forecast of off-system wholesale sales and thermal generation.

Q. What is the increase to the Oregon-allocated NPC and the impact to Oregon rates?

As shown in Exhibit PAC/101, there is an increase to Oregon-allocated NPC of approximately $78.2 million and an increase in PTCs (decrease to rates) of approximately $1.8 million. After adjusting for the variance from loads, the 2023 TAM results in an increase to Oregon rates of approximately $70 million. Unless otherwise specified, references to NPC throughout my testimony are expressed on an Oregon-allocated basis. As explained in Ms. Ridenour's testimony, the 2023 TAM results in an overall average rate increase of approximately 5.6 percent.

Q. Does the proposed rate increase for the 2023 TAM reflect changes in Oregon load since the 2022 TAM?

A. Yes. The 2023 load forecast used in the Company's calculation of NPC reflects an increase in Oregon load compared to the 2022 forecast loads in the 2022 TAM. Due to the increase in Oregon load, the Company anticipates it will collect approximately $6.4 million more than what was approved in the 2022 TAM, reducing the overall requested rate increase.

Q. Please explain how the EIM inter-regional and greenhouse gas (GHG) benefits are treated in the 2023 TAM.

A. PacifiCorp's initial filing includes a forecast of both the inter-regional benefits and GHG benefits from participation in the EIM. The expected incremental inter-regional EIM benefits relative to the optimized NPC modeled by the Aurora model are reflected as a reduction to the NPC forecast. The total-company inter-regional EIM benefits included in the 2023 TAM are [redacted], a decrease of [redacted] in benefits from the 2022 TAM. The GHG benefit is [redacted], a [redacted] increase from the 2022 TAM.

IV. DISCUSSION OF MAJOR COST DRIVERS IN THE TAM

Q. Please explain NPC.

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

Q. How does the TAM relate to NPC?

A. In the 2017 TAM Order, the Commission described the TAM and its purpose as follows:

> PacifiCorp's TAM is an annual filing in which PacifiCorp projects the amount of [NPC] to be reflected in customer rates for the following year, as well as to set transition charges for customers electing to move to direct access. The TAM effectively removes regulatory lag for the company because the forecasts are used to adjust rates. For that reason, the accuracy of the forecasts is of significant importance to setting fair, just and reasonable rates. Our goal, therefore, is to achieve an accurate forecast of PacifiCorp's [NPC] for the upcoming year.[3]

Q. Please explain how PacifiCorp calculates NPC.

A. PacifiCorp calculates NPC for a future test period based on a forecast using Aurora, which is a production cost model that simulates the operation of the Company's power system on an hourly basis. This is the first year that PacifiCorp is using the Aurora model for the TAM. More details on the Aurora model as compared to the Generation and Regulation Initiative Decision Tool (GRID) model are provided later in my testimony.

Q. Has the Company proposed any modeling changes in the 2023 TAM?

A. Yes. The Company is proposing the following modeling changes:

[3] *In the Matter of PacifiCorp, d/b/a Pacific Power, 2017 Transition Adjustment Mechanism*, Docket No. UE 307, Order No. 16-482 at 2-3 (Dec. 20, 2016).

- Wholesale sales market caps will be based on the four-year historical average of short-term firm, balancing and spot, differentiated by on-peak and off-peak hours;
- The day-ahead real-time (DA/RT) price adder will be changed to a percentage of market prices;
- The regulating reserve requirement will be updated to reflect higher reliability and resource adequacy standards consistent with the Company's operations;
- The trapped energy revenue will be updated to reflect its impact more accurately on NPC; and
- The planned maintenance outages will be based on the Company's budgeted outage plan.

These changes are described more fully below in my testimony.

Q. What inputs were updated for this filing?

A. The Company updated all inputs to the 2023 TAM, including system load, wholesale sales and purchase contracts for electricity, natural gas and wheeling, the OFPC market prices for electricity and natural gas, fuel expenses, and the characteristics and availability of the Company's generation facilities.

Q. What is the date of the OFPC the Company used in this filing?

A. PacifiCorp's filing uses the OFPC dated December 31, 2021.

Q. Will the Company continue to update the OFPC through the pendency of this proceeding?

A. Yes. In accordance with the current TAM Guidelines, PacifiCorp's reply update will incorporate the most recent OFPC that is available when the update is prepared, the

November indicative update will incorporate an OFPC from within nine days of the filing, and the November final update will incorporate an OFPC from within seven days of the filing.

Q. Please generally describe the changes in NPC compared to the 2022 TAM.

A. The increase in NPC is driven by a reduction in wholesale sales revenue, increased natural gas fuel expenses, increased purchased power expense, and increased wheeling and other expenses. This is partially offset by a reduction in coal fuel expense. Table 2 illustrates the change in total-company NPC by category from the 2022 TAM NPC to the 2023 TAM NPC.

Table 2: NPC Reconciliation

	($ millions)	$/MWh
OR TAM 2022	**$1,369**	**$22.61**
Increase/(Decrease) to NPC:		
Wholesale Sales Revenue	252	
Purchased Power Expense	78	
Coal Fuel Expense	(47)	
Natural Gas Fuel Expense	21	
Wheeling and Other Expense	10	
Total Increase/(Decrease) to NPC	**315**	
OR TAM 2023	**$1,684**	**$27.25**

Q. Please explain the reduction in wholesale sales revenue.

A. The reduction in wholesale sales revenue is driven by lower sales volumes and lower projected transaction prices. Total-company wholesale sales revenue is $252.3 million lower than the 2022 TAM with most of the reduction coming from market transactions (represented in Aurora as short-term firm and system balancing sales). Market sales transactions in the 2023 TAM are 2,359 gigawatt-hours (GWh) lower than in the 2022 TAM. The average market price of wholesale sales in the

2023 TAM is $54.54/MWh, while in the 2022 TAM the average market price was $68.78/MWh, a 26 percent decrease.

Q. What are the components of wholesale sales in NPC?

A. In NPC, wholesale sales represent the wholesale revenue the Company receives from various power sales activities. Long-term firm sales, short-term firm sales and system balancing sales comprise the total-company wholesale revenues. Long-term firm sales are wholesale sales contracts longer than a one-year period. Short-term firm sales are wholesale sales contracts shorter than a one-year period. Both long-term and short-term firm sales are executed transactions during the forecast period on specific terms. System balancing sales are Aurora model driven market transactions, which are used in the model to economically balance load and resources in the forecast period.

Q. How does each component of wholesale sales revenue in the 2023 TAM compare to the 2022 TAM?

A. In the 2023 TAM, long-term firm wholesale sales revenue increases from the 2022 TAM due to the addition of a new long-term sales contract. The system balancing sales revenue decreases by $252.28 million as compared to the system balancing sales in 2022 TAM.

The short-term firm revenue in this filing is lower than what is reflected in the final update of the 2022 TAM proceeding by $19.5 million due to absence of any short-term firm sales for 2023. This is because the short-term firm sales are the actual short-term firm transactions, or hedges, the Company has entered for the test period. The Company hedges on a rolling 36-month horizon but most of the trading activity is for the next 12 months. Therefore, it is expected that the final TAM filed in November will have larger volumes of short-term firm sales than the initial TAM filing due to timing. The volumes of short-term firm sales for the test period will typically increase with each subsequent TAM update until the final TAM filing.

Q. Why did the purchased power expense increase?

A. The $78.3 million increase in purchased power expense is primarily due to higher market purchase prices. Market purchases (represented in Aurora as short-term firm and system balancing purchases) in the current case have an average price of $59.14/MWh, while the 2022 TAM was an average price of $43.97/MWh.

The average price of the long-term contracts included in the 2023 TAM is $40.85/MWh, compared to the average price of long-term contracts in the 2022 TAM of $41.72/MWh.

Total-company expense for power purchased from Qualifying Facilities (QFs) decreased by $11.32 million with a small decrease in the generation volume compared to the 2022 TAM.

No new QFs are forecast to come online in the 2023 TAM forecast period. In subsequent updates, the Company will update the NPC study as new information becomes available per the TAM Guidelines and apply the contract delay rate to new QFs expected commercial operation dates in the updates.

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

A. Total-company coal fuel expense is $47.03 million lower than the 2022 TAM due to the lower coal generation volume at the Company's coal plants. Mr. Owen provides additional detail regarding the cost of coal during the test period in his direct testimony.

Q. What is the treatment of Jim Bridger Units 1 and 2 in the TAM?

A. Generation and coal fuel costs associated with both Jim Bridger Units 1 and 2 are included in the TAM. PacifiCorp discussed the current status of the Wyoming state implementation plan and regional haze requirement as it pertains to the Jim Bridger units at length in its motion to amend the order from the 2022 TAM.[4]

Q. Please discuss the change in natural gas fuel expense compared to the 2022 TAM.

A. Total-company natural gas fuel expense in the 2023 TAM is $20.64 million higher than natural gas fuel expense in the 2022 TAM. The higher natural gas fuel expense in this TAM is due to higher projected generation offset by declining prices. The average cost of natural gas generation decreased from $31.55/MWh in the 2022 TAM to $27.87/MWh in the current proceeding, a 10 percent decrease. Generation from natural gas plants in the 2023 TAM is 1,626 GWh more than the 2022 TAM, a 17 percent increase.

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

A. Expenses in this category are $9.8 million higher primarily due to an update based on actual 2021 wheeling expenses.

Q. Did PacifiCorp provide advance notice to the parties regarding the modeling changes proposed in this case?

A. Yes. In compliance with the TAM Guidelines, PacifiCorp provided notice of changes

[4] *In the Matter of PacifiCorp d/b/a Pacific Power 2022 Transition Adjustment Mechanism*, Docket UE-390, PacifiCorp's Motion to Amend Order No. 21-379 (Feb. 11, 2022).

to the Company's modeling of NPC in the 2023 TAM. This notice was provided on January 28, 2022 and is included as Exhibit PAC/108.

V. TRANSITION TO AURORA AND IMPLEMENTATION OF NPM

A. Transition to Aurora

Q. Why is PacifiCorp filing this TAM with the Aurora model?

A. PacifiCorp has used the GRID model since it was deployed by the Company in 2008 and discontinued its use for NPC filings in 2021. Consequently, the Company has been transitioning to Aurora, which is produced by Energy Exemplar, for the purposes of annual NPC filings. The Aurora model provides additional functionality, increases usability, as well as compatibility with the Company's information technology. To date, PacifiCorp has filed NPC forecasts using Aurora in California and Washington. Additionally, the Aurora model includes certain functionality necessary to accommodate the allocation of an NPC forecast in a post-interim period as contemplated in the 2020 PacifiCorp Inter-Jurisdictional Allocation Protocol (2020 Protocol) where actual NPC will use the NPM to perform the allocation of state-specific NPC for ratemaking purposes in the post-interim period. I will address the NPM later in my testimony.

Q. How does the Aurora model work?

A. Aurora is designed to model the competitive wholesale electricity market and produce hourly locational marginal prices (LMP) to meet load requirements at various locations (referred to as "zones"). Like other production cost models, the objective function is to meet the load at the lowest possible cost. This is accomplished by simulating the dispatch of available resources, both supply-side and demand-side, within physical and economic constraints of the resources, as well as profiles of the load requirements. These simulations determine the resources at the margin in each hour to serve the next incremental amount of load requirements of the zones and the costs of the resources at the margin, which set the market prices of the zones. PacifiCorp held a workshop with TAM parties on February 15, 2022, that covered these issues, and that presentation is provided as Confidential Exhibit PAC/105.

Q. How does Aurora compare to GRID?

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

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

A. Aurora co-optimizes dispatch and commitment decisions, allowing the model to create a reliable dispatch forecast that satisfies all ancillary service requirements and appropriately reflects the associated costs. In addition, Aurora can receive more than one incremental price for the purpose of forecasting dispatch of coal fueled 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 an optimized dispatch forecast for coal plants and units that are subject to volumetric constraints and tiered pricing across a range of consumption levels.

Validation Process for Aurora

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

A. Both GRID and Aurora are production cost optimization models that use linear programming with similar inputs that attempt to forecast and satisfy the Company's load obligation 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: a) verify if the outputs of non-dispatchable resources match the inputs, and the outputs match between Aurora and GRID; b) refine input parameters in Aurora that are either not available in GRID or have a different impact on optimization; and c) research the reasons why the same dispatchable resources with generally the same inputs produce different results from Aurora and GRID. And, finally, the total NPC from the two models is 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. First, the inputs in the two models are not the same because Aurora allows more inputs and at different levels of granularity. Additionally, Aurora uses a Mixed Integer Program solver that aids in co-optimizing commitment and dispatch decisions while GRID does not natively accomplish this. Differences in the optimization logic may lead to different unit availabilities and different dispatch based on the economics at those times.

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

A. Yes. Please refer to Confidential Exhibits PAC/103 and PAC/104, which contain the Aurora and GRID NPC Test reports that the Company used to validate the Aurora model. The test reports show that there was a 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 logic. 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 transaction forecasts. This is why the validation process compared the overall outcome of the NPC test report.

Q. Would running GRID with the inputs used for the TAM 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 logic differs between the models even though the underlying principles are similar. 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 the GRID model and found that the overall NPC results exhibited a tolerable variance between the two models.

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 quite 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 substantially the same but require slightly modified calculation methodologies to account for the treatment given to those inputs in Aurora (Unit Minimum Capacities and Thermal Outage Rates, for example).

Q. How is output from Aurora incorporated into Oregon NPC?

A. The Aurora model results are used to create a total-company NPC forecast. The total-company NPC report is very similar to the report that has been used in the past. Those results are then allocated according to the 2020 Protocol to arrive at an Oregon-allocated NPC forecast.

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

A. As mentioned above, Aurora accounts for unit minimums and equivalent outage rates (EOR) differently, and both required material updates because of differences in the modeling of unit availabilities. Aurora scales both the unit capacity and the unit minimum in response to a derate. 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 stable operating level. A relatively straightforward solution was adopted by the Company that only required the calculation and input of an hourly unit minimum timeseries to account for derates. To avoid the possibility of infeasibilities, 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 fueled 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 an optimized dispatch forecast for coal plants and units that are subject to volumetric constraints and tiered pricing across a range of consumption levels.

Q. Do you still need the DA/RT Adjustment 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 market prices. The price volatility is related to the market conditions in the period that the Company experienced at the time when making DA/RT transactions. The DA/RT costs are 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, PacifiCorp 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 prices.

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

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

Finally, buying or selling standard block products for monthly and daily average requirements will not result in a perfect balance of load and resources. This difference then must be closed out in the real-time market where the Company is a price-taker.

Q. Has PacifiCorp consulted with Energy Exemplar regarding possible options to address the need for the DA/RT adjustment within the model?

A. Yes; the Company has discussed the DA/RT adjustment with Energy Exemplar, including its purpose. Aurora does not currently have a feature or other functionality that could replace the need for the DA/RT adjustment. PacifiCorp will continue to explore the viability of possibly adding functionality to the Aurora model in the future.

Aurora and the NPM

Q. How is Aurora related to the NPM?

A. The switch to the Aurora model was necessary to allocate forecast NPC as contemplated in the 2020 Protocol where actual NPC will use the NPM to perform the allocation of state-specific NPC for ratemaking purposes in the post-interim period. The Aurora model provides a locational pricing output that is not available in GRID but is necessary for regulatory proceedings that use an NPC forecast, such as the TAM. The location pricing as an output of the forecast model is necessary because without it an NPC forecast, like the one included in the TAM, could not be allocated to specific states in the same manner in which actual NPC will be allocated to states under the NPM allocation methodology.

Q. You described the transition to Aurora as being necessary to accommodate the NPM allocation methodology; will you please briefly describe the NPM?

A. The NPM is a Framework Issue in the 2020 Protocol and is the anticipated future allocation methodology to be used for the inter-jurisdictional allocation of NPC. The 2020 Protocol defines NPM as "a method for pricing electricity proposed by the

Company that is based on the marginal cost ($/MWh) of serving the next increment of demand at a given pricing node consistent with existing transmission constraints and the performance characteristics of resources."[5] To have the information necessary (*i.e.*, day-ahead, hourly LMP) to allocate actual NPC using the NPM, the Company contracted with the CAISO to receive optimized day-ahead advisory schedules that are used to inform the Company's day-ahead schedules. In other words, the NPM consists of two components: (1) the operational, "dispatch", or day-ahead schedules from CAISO; and (2) the allocation methodology. Aurora is necessary to allocate NPC in a regulatory proceeding that relies on an NPC forecast.

Q. Has PacifiCorp implemented the allocation methodology?

A. No, but PacifiCorp is receiving day-ahead schedules from CAISO. This day-ahead schedules process was implemented in January 2021.

Q. When will the allocation methodology be fully implemented?

A. The NPM is a Framework Issue in the 2020 Protocol and is currently part of the ongoing MSP negotiations. Though there are still items that need to be resolved in the MSP, the 2020 Protocol contemplates that the NPM will be used to set rates once a new allocation methodology is adopted.

VI. NODAL PRICING MODEL FEE

Q. Please describe the NPM fee that PacifiCorp pays to CAISO.

A. PacifiCorp pays a $2.1 million fee quarterly ($8.3 million annually) for NPM services. CAISO based the fee on its estimated expenses to provide NPM services to PacifiCorp. The basis for the estimated cost is the direct and indirect time and

[5] *In the Matter of the Application of PacifiCorp for an Investigation of Inter-Jurisdictional Issues*, Docket No. UM 1050, Exhibit PAC/101, Appendix A at 5-6 (Dec. 3, 2019).

expense necessary for CAISO to perform the NPM service for PacifiCorp. The NPM services that CAISO provides are the production of separate day-ahead nodal pricing results within PacifiCorp's balancing authority areas. The NPM services include CAISO calculating the credit each generator will receive for their scheduled generation in the day-ahead schedule and the price which load would pay for its day-ahead schedule.

Q. What are the operational benefits of NPM?

A. As the Company has discussed in prior proceedings, the benefits from nodal dispatch and NPM come from having more efficient day-ahead setup.[6] Put another way, a more efficient day-ahead setup results in fewer changes between the day-ahead setup and real-time dispatch, which lowers actual NPC by avoiding those changes. Notably, as the Company has discussed before, this benefit is impossible to track because it is impossible to know what the day-ahead setup would be without NPM.[7] However, this change will serve to improve operational efficiency and allow the Company's transition between day-ahead and real-time to better reflect the sort of efficiency present in its model results.

Q. Are the operational benefits of the NPM captured in the NPC forecast using the Aurora model?

A. Yes. NPM results in a more efficient day ahead set-up which results in fewer changes between the day-ahead schedule and real-time dispatch, which lowers actual NPC by avoiding those changes.[8] The benefits of NPM are already incorporated into the

[6] *In the Matter of the Application of PacifiCorp for an Investigation of Inter-Jurisdictional Issues*, Docket No. UM 1050, Exhibit PAC/300, Wilding/11 (Dec. 3, 2019).
[7] *Id.*
[8] *Id.*

forecast for NPC, because NPC models dispatch in a single step, so there is already no change between day-ahead schedules and real-time dispatch. Therefore, the costs of the changes between day-ahead schedules and real-time dispatch do not exist in the model. Since those costs do not exist in the model, there are no costs to avoid or benefits to be imputed on top of the forecast.

However, these costs are seen in actual NPC because there is a difference between the day-ahead schedules and real-time dispatch in actual operations. NPM incrementally reduces that difference in actual operations and those benefits are embedded in actual NPC.

Q. Does that mean Aurora is using a nodal topology?

A. No. The version of Aurora used by the Company is set up to use a zonal topology. The NPM is an allocation framework that leverages CAISO's day-ahead dispatch engine and corresponding advisory settlements to allocate the Company's actual NPC to each state. However, the NPC forecast from Aurora uses a zonal topology but with the necessary locational pricing to perform the allocations. Notably, the term 'nodal' in the NPM allocation framework does not refer to the modeling topology used in Aurora.

Q. Please explain why Aurora does not use a nodal topology.

A. In implementing the Aurora model, the topology was built with the NPM in mind. However, Aurora is not using a nodal topology as it was not feasible for multiple reasons. First, a nodal topology in Aurora is a power flow model that relies on the entire Western Electricity Coordinating Council (WECC) nodal topology and allows for the flow of energy for the entire WECC footprint. Additionally, the Aurora run times to produce an annual NPC forecast using a nodal topology are excessive and would preclude practical usage of the model. Furthermore, access to the WECC-wide nodal topology is limited and there are restrictions on individuals who are granted access being able to share the data with others. That creates obvious difficulties in making work papers available in a regulatory context and would also limit the Company's ability to share NPC work papers internally.

Q. The Commission included $1.09 million reduction to NPC as a proxy for nodal pricing benefits in the 2022 TAM Order.[9] Is it appropriate to continue this reduction?

A. No; as stated above, the Aurora model already captures the NPM benefits that will be realized in actual operations. In fact, the Commission noted in their order that "we anticipate nodal pricing model benefits across PacifiCorp's two Balancing Authority Areas will be captured with the implementation of Aurora for planning in the 2023 TAM."[10]

VII. MODELING IMPROVEMENTS

Q. In addition to the transition to Aurora, is PacifiCorp incorporating additional modeling improvements into this year's TAM?

A. Yes. PacifiCorp is proposing the following modeling improvements:

- Wholesale sales market caps will be based on the four-year historical average of short-term firm, balancing and spot sales, differentiated by on- and off-peak

[9] Order No. 21-379 at 33.
[10] *Id.*

hours. This was completed consistent with the Commission's continued review of this issue as identified in Order No. 21-379.[11]

- The regulating reserve requirement will be updated to reflect higher reliability and resource adequacy standards consistent with the Company's 2021 IRP.
- The planned maintenance outages will be based on the Company's budgeted outage plan.
- The DA/RT price adder will be changed to a percentage of market prices.
- The trapped energy revenue will be updated to reflect its value more accurately.
- The maximum generating capacity of certain thermal generating units has been updated to reflect actual generating capacity during the summer months.
- Inclusion of start-up fuel costs for natural gas units.

Besides the modeling improvements there is one change to include: start-up fuel costs for natural gas units in NPC cost, which has not previously been included in the TAM.

A. Market Capacity Limits

Q. Please explain market capacity limits.

A. Market capacity limits, or market caps, refer to the physical limits in place at the different market hubs. These are transfer capabilities that the model is subject to when there is excess generation available that limit the model's ability make excess off-system sales.

[11] *In the Matter of PacifiCorp d/b/a Pacific Power 2022 Transition Adjustment Mechanism*, Docket UE-390, Order No. 21-379 at 28 (Nov. 1, 2021).

Q. Please explain the purpose of modeling market caps in Aurora.

A. By default, the Aurora model assumes unlimited market depth for system balancing sales and purchases. It does not consider load requirements, transmission constraints, market illiquidity, or static assumptions about market prices that prevent the Company from making sales or purchases at the forecast price. The Company's transmission access to a market point limits its ability to sell its generation in that market; similarly, counterparties' demand for purchases is limited by their transmission access and their own load and resource balance. Thus, without market caps the Aurora model has no constraints to reflect counterparties' inability to make economic transactions resulting in increased sales transactions that are not reflective of actual operational constraints.

Q. Please explain PacifiCorp's market cap methodology.

A. PacifiCorp has revised the methodology to base wholesale sales market caps on the historical average of short-term firm, balancing and spot sales sometimes referred to the average of averages approach. Using the four-year historical average produces a more accurate approach that avoids excess market sales in the forecast artificially driving down NPC. The lower market caps better reflect system operations and improves the overall NPC forecast by avoiding excess market sales. In the 2022 TAM, the Commission indicated that the market caps adopted in that proceeding would apply only to the 2022 TAM and that the Commission "would evaluate the reasonableness of Aurora's forecast when we see it in the 2023 TAM."[12]

[12] Order No. 21-379 at 28.

Q. Please explain how market caps were modeled in the 2022 TAM indicative and final update.

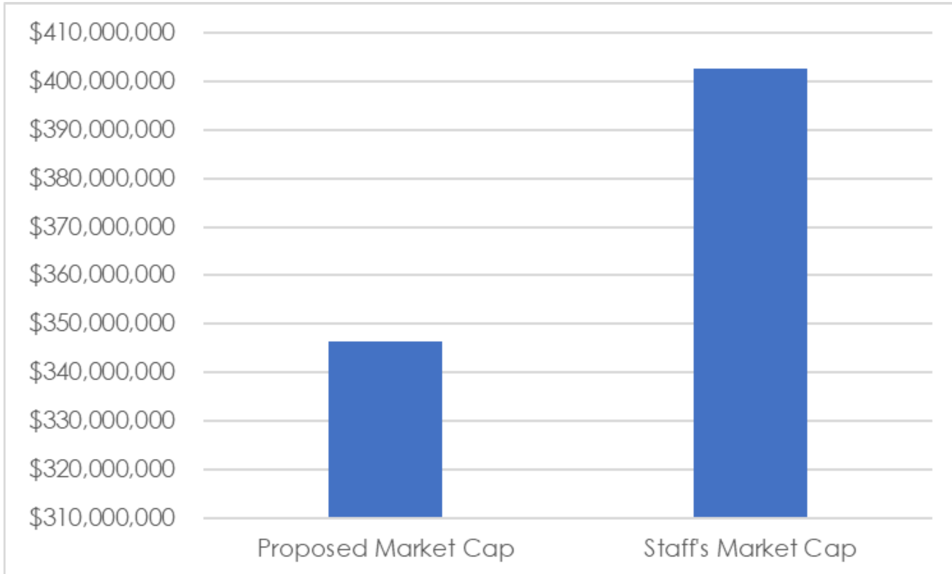
A. Market Caps modeled in the 2022 TAM indicative and final update were a result of the Commission's order in the 2022 TAM that instructed the Company to base its monthly market caps on "the third quartile of averages" that was suggested by the Public Utility Commission of Oregon Staff (Staff).[13] This means that PacifiCorp was required to average the two highest values of the four highest monthly sales at each hub to calculate the market cap. Staff's market cap methodology was less restrictive and increased the volume of wholesale sales.

Q. Please explain the impact of the third quartile of averages market caps.

A. The results from the implementation of Staff's market cap methodology indicate a tendency to overstate the wholesale sales capacity which in turn leads to a distorted impact on thermal dispatch and generation. The combined effect is a gross overestimation of market sales by the model. Staff's market cap methodology results in an increased market depth that PacifiCorp operationally has no access to; leading to increased thermal generation levels that are not reflective of PacifiCorp's actual operation of thermal plants. Figure 1 below shows the disparity in market sales estimations between the Company's and Staff's market cap methodologies.

[13] Order No. 21-379 at 26.

Figure 1: Total System Balancing Sales



Furthermore, Figure 2 below shows a comparison between actual market sales volume for historical periods (2019–2021) identified in navy blue as well as forecasted market sales volume in the 2022 Final TAM (red) and 2023 TAM (light blue) filings.

Yet, as seen below, using Staff's Market Cap methodology artificially inflates the market depth when compared to PacifiCorp's methodology. Staff's methodology leads to increased sales (as seen in the 2022 TAM values), which are greater than historical market sales levels. Therefore, the Company recommends the Commission adopt PacifiCorp's market cap methodology as it is more reflective of the Company's operational reality.

Confidential Figure 2: Market Sales Volumes[14]

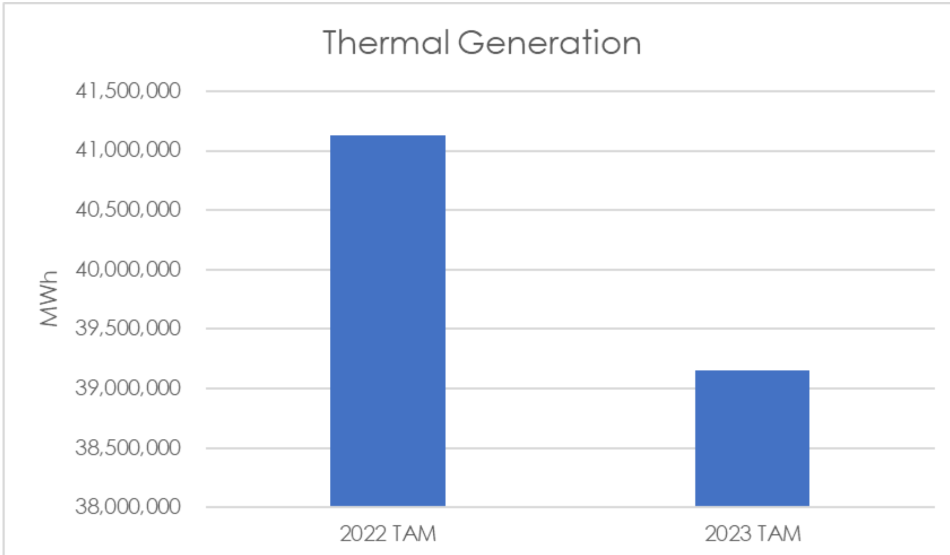
[redacted]

Q. Please explain how the modeled thermal generation in this TAM compares to 2022 TAM.

A. As seen in Figure 3 below, thermal generation level in the 2022 TAM is greater than 2023 TAM by 1.97 million MWh. This decrease in generation levels can be attributed to 2023 TAM proposed market depth which is reflective of PacifiCorp's actual operations.

[14] Actual (2019-2021) Sales data is from PacifiCorp's filed PCAM and is net of bookouts. Additionally, actual 2021 sales data is preliminary and has not yet been finalized.

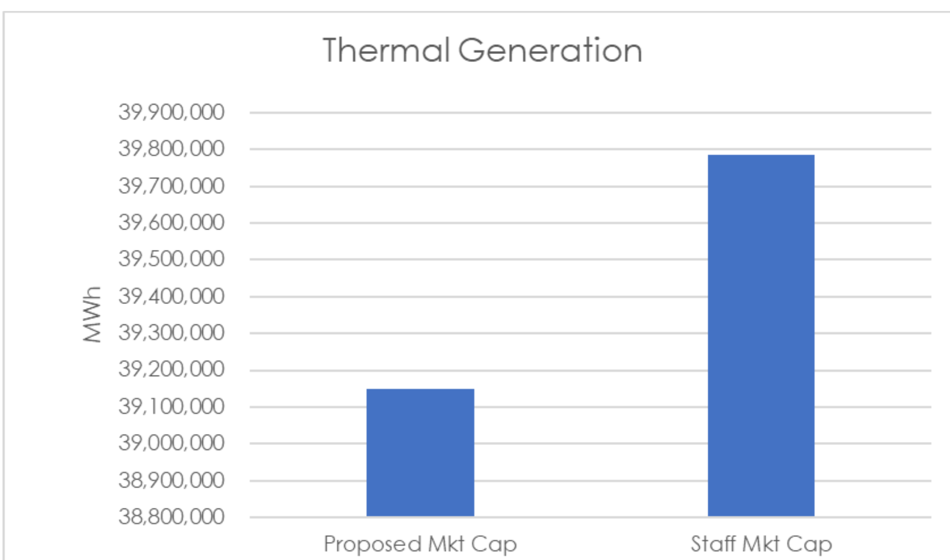
Figure 3: Thermal Generation between the 2022 and 2023 TAM



Q. How does the thermal generation under PacifiCorp's market cap methodology compare to the thermal generation using Staff's market cap methodology?

A. As seen in Figure 4 below, PacifiCorp's proposed market cap limits reduce thermal generation, thereby leading to reduced emissions. Using Staff's market caps, thermal generation is significantly higher and not reflective of Oregon mandated policies.

Figure 4: Thermal Generation Between Different Market Cap Methodologies



Q. Please quantify the impact of the market cap methodology changes proposed by the Company.

A. The change in the market cap methodology increases NPC by $5.9 million primarily driven by decreases in sales revenues. The decline in sales revenue was partially offset by reductions in coal fuel expense, natural gas fuel expense, and purchased power expense.

Regulating Reserve Requirement

Q. What is the current methodology that PacifiCorp uses to model the Regulation Reserve Margin requirement?

A. In the 2022 TAM, regulating reserve requirements were modeled based on 2019 IRP results which assumed a one percent Loss of Load Event (LOLE) expressed in hours per year.

Q. Please provide a brief overview of this adjustment.

A. The previous regulating reserve requirement assumption does not adequately reflect the higher operating, reliability and resource adequacy requirements PacifiCorp is currently subject to. Therefore, the Company is proposing a change in the treatment of the regulating reserve requirement. Specifically, the Company is proposing to increase the regulating reserve requirements to be consistent with the 2021 IRP results that reflect a LOLE of 30 minutes per year which is a higher adequacy standard and more reflective of the operating standards than the previously used LOLE standard of 1 percent.

Q. Please quantify the impact of this adjustment.

A. The impact of this adjustment is an increase to NPC of $17.58 million which is primarily driven by increased costs related to market purchases. Due to the increased resource adequacy standard, resource generation availability to meet load is reduced, thereby increasing the quantity of power purchased from the market to meet load obligations.

Q. Is PacifiCorp providing additional information on the appropriateness of this adjustment?

A. Yes, please refer to the testimony of Mr. MacNeil, who describes this adjustment in greater detail.

Planned Outages

Q. What is the current methodology used by PacifiCorp in modeling generation outages?

A. PacifiCorp currently uses normalized historical outages based on four years of historical outages and the resulting available generation capacities at each thermal plant.

Q. What changes is PacifiCorp proposing with regards to how generation outages are modeled in Aurora and why?

A. The Company is proposing to replace normalized outage assumptions with actual budgeted and/or planned outages to accurately reflect the planned outages that are expected to take place during the forecast period. Since the TAM is an annual filing, it makes sense that the planned outages would be updated annually based on the Company's budgeted outage plan for the forecast period as opposed to an historical average of planned outages. The use of budgeted planned outage schedules represents a basic improvement in data quality that will lead to increased accuracy of the NPC forecast.

Q. Please explain how this adjustment improves the accuracy of the NPC forecast.

A. Using budgeted planned outage schedules for thermal plants allows the model to be based on the planned outage schedules for the forecast period. This in turn allows the Aurora model to create a dispatch schedule that is reflective of PacifiCorp's planned operations based on best available information at the time of the TAM modeling instead of an average outage schedule based on historical data. Additionally, this helps reduce NPC forecast error.

Q. Please quantify the impact of this adjustment on the 2023 TAM base run.

A. The impact of this adjustment is a $3.62 million increase to NPC due to the reduced generation levels from thermal plants, reduced wholesale sales and increased system balancing purchases. In future TAM filings this adjustment could result in an increase or decrease to NPC depending on the budgeted planned outage schedule for the forecast period.

DA/RT Adjustment Price Component

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

A. The price adder 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, PacifiCorp 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 prices. Previously these prices were calculated by adding or subtracting a flat dollar amount to the hourly scaled prices from the OFPC.

Q. Please explain how changing the DA/RT adjustment 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. Please quantify the impact of this adjustment.

A. The impact of this adjustment is an increase of $5.21 million to NPC. The primary driver for this change is the captured intra-month market volatility.

Trapped Energy

Q. Please explain PacifiCorp's adjustment to trapped energy.

A. Primarily, trapped energy is a modeling concept only and does not exist in operations. It represents any generation that is not able to be used to serve load due to transmission constraints. Because of limited transmission, the trapped energy does not make it to market. In the past, the Company has valued trapped energy at 75 percent of the market prices, which lead to overstated sales revenue. Since this concept does not exist in actual operations, the value of trapped energy should be zero. However, PacifiCorp is simply proposing to lower the current value from 75 percent to 25 percent of market value.

Q. Please quantify the impact of this adjustment.

A. The impact of this adjustment is an increase of $47,434 due to decreased sales revenue.

Thermal Attributes

Q. What updates did PacifiCorp 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 temperature increases. As temperatures are historically hotter during the summer months of June through September, the generation output from the thermal plants decrease during those months. To account for this operational constraint, the Company updated the maximum generation capacity at certain plants during the summer months of June through September.

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

A. Because generating capabilities of 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 could 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 summer temperatures is reflective of actual weather-related constraints.

Q. Please quantify the impact of this adjustment.

A. The impact of this adjustment is an increase of $6.21 million driven by increased market purchases.

Start-up Costs for Natural Gas Units

Q. Please explain this adjustment.

A. Consistent with the TAM Guidelines, start-up fuel costs for natural gas units are included in NPC as they are accounted for in Federal Energy Regulatory Commission Account 547.[15] In the past, the Company's NPC forecasts have not included natural gas start-up fuel costs and consequently they have not been included in rates.

Q. Please explain how this adjustment results in more accurate forecast NPC and better reflects PacifiCorp's actual operations.

A. PacifiCorp incurs costs related to cycling its gas-fired units. The proposed addition captures and accounts for this previously unaccounted for cost element, therefore aligning the NPC modeling approach more closely with the operational costs incurred

[15] *In the Matter of PacifiCorp, d/b/a Pacific Power, 2009 Transition Adjustment Mechanism*, Docket No. UE 199, Order No. 09-274, Appendix A at 14 (Jul. 16, 2009).

by the Company. GRID did not have the ability to report startup costs outside of dispatch costs while Aurora through its reporting capabilities allows us to capture start-up costs.

Q. Please quantify the impact of including natural gas start-up costs in the TAM.

A. The impact of this adjustment is an increase of $1.61 million.

VIII. COMPLIANCE WITH 2021 AND 2022 TAM ORDERS

Q. The 2021 TAM order described several actions that need to be taken prior to the transition to Aurora. What were those actions?

A. In Order No. 20-392, the Commission adopted the stipulation reached between the parties.[16] PacifiCorp agreed to the following:

- Hold a workshop on the transition from GRID to Aurora prior to filing a NPC forecast with Aurora, along with providing licenses to the model and other inputs to Parties;
- Provide one model run per intervenor, as long as the request is reasonable and PacifiCorp has reasonable time to complete the model run;
- Removal of the "must run" setting as part of the transition to Aurora; and
- Performing an informational model run that removes any operational constraints related to the minimum take provisions in the coal supply agreements and uses an average coal price for purposes of dispatching coal plants (to be provided in 15-day workpapers).

Q. Did PacifiCorp hold the workshop as requested in the 2021 TAM Order?

A. Yes; the workshop was held on February 15, 2022, where PacifiCorp brought in

[16] *See In the matter of PacifiCorp dba Pacific Power's 2021 Transition Adjustment Mechanism*, Docket No. UE 375, Order No. 20-392 (Oct. 30, 2020).

Energy Exemplar to provide an overview of the Aurora model, and provided a presentation to address the NPM and the DA/RT. The overview of Aurora is attached to my testimony as Confidential Exhibit PAC/105.

Q. Were there items that needed to be followed-up on from the 2022 TAM Order?

A. Yes. The following table lists the information that was requested as part of the order in the 2022 TAM and describes where it has been provided:

Table 3: **Information Requested in Order No. 21-379**

Request	Details
PacifiCorp is directed to complete a follow-up economic cycling study as requested by Staff. This would include improved modeling to "show economic cycling in a way that meets the requirements of a reliable generation plan." "The overall question that PacifiCorp's follow-up economic cycling study should address is whether economic cycling of units, with reliability considerations factored in, creates savings for customers."	Provided as Section IX in this testimony.
PacifiCorp is required to report four years of data on the initial incremental price and the final dispatch tier price, and costing tier price for each plant from the 2020 TAM forward.	Will be provided in the 15-day workpapers in this filing.
PacifiCorp is required to update and file its Jim Bridger Long Term Fuel Plan Document in the 2023 TAM. "PacifiCorp should be informed by an average cost analysis that may present a different view than the traditional TAM modeling of how the long-term fuel plan could optimize a new Black Butte CSA, the shutdown or conversion of the units, and the level of production at the units by considering the full cost of coal."	PacifiCorp has requested an extension to file this document.
The Commission requests PacifiCorp include "a discussion of [M&S] costs in its updated Jim Bridger long term fuel plan so that parties have the opportunity to review components as well as the whole of BCC costs."	Provided in the testimony of James Owen.
Provide a sample calculation of Schedule 296 as applicable to customers currently served under Schedule 30 and Schedule 48 within 30 days of filing the TAM;	To be provided to parties on May 30 consistent with Order No. 21-379.
PacifiCorp needs to present analysis on the costs and benefits of pursuing Huntington's re-opener clause. If PacifiCorp does not thoroughly explore the costs and benefits of contract termination or renegotiation, we would be willing to entertain an argument for a disallowance.	As discussed in the testimony of James Owen, this report is anticipated to be provided on April 15, 2022.
PacifiCorp needs to update the QF table in the order with 2021 data, and to address the question of why it has continued to over forecast QFs in recent years.	Discussed in this testimony, Section X.

IX. COAL CYCLING REPORT

Q. Please explain the Commission's requirement from the 2022 TAM Order.

A. In the 2022 TAM Order, the Commission requested that PacifiCorp perform a follow-up study to the economic cycling report produced in the 2022 TAM. Specifically, it should address "whether economic cycling of units, with reliability considerations factored in, creates savings for customers."[17]

Q. Has the Company removed the "must run" setting in this year's TAM?

A. Yes; as a result of the settlement reached in the 2021 TAM, PacifiCorp agreed to remove the "must run" setting as part of the transition to Aurora.[18] Removal of the must run setting essentially enables the model to "economically cycle" the coal plants throughout the year, subject only to the operational constraints that the plants face in reality.

Q. What impacts do you observe as a result of removing the "must run" setting?

A. The results demonstrate that removal of the "must run" setting in Aurora fundamentally distorts NPC modeling, necessitates multiple adjustments to ensure that actual plant operations are accurately modeled, and results in a less operationally consistent outcome. However, as required by the terms of the 2021 TAM settlement, PacifiCorp is providing NPC based on an Aurora run that removes the "must run" setting.

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[17] Order No. 21-379 at 8-9.
[18] *In the matter of PacifiCorp dba Pacific Power's 2021 Transition Adjustment Mechanism*, Docket No. UE 375, Order No. 20-392, Appendix A at 6 (Oct. 30, 2020).

Q. Please explain how the removal of the must run setting is accommodated in Aurora?

A. Aurora has a binary setting that lets the user turn off the "must run" setting. When the setting is turned off, operational constraints such as minimum up and down times and start-up costs become binding; increasing the complexity of the optimization problem Aurora is attempting to solve as evidenced by the model run time increasing from 90 minutes (must run setting turned on) to seven hours per run with it turned off.

Q. Please explain how the "must run" setting reflects actual operations.

A. In actual operations, the Company would not entirely shut down a coal unit for a short period of time when its dispatch price might be higher than other resources for several reasons.

Aurora's "must run" settings approximate real operations in two ways: first, using the setting avoids additional start-up costs that would be incurred if the units were entirely shutdown. Second, entirely shutting down a coal unit creates reliability risks because of the start time necessary to bring a coal unit back online once it is entirely shut down. As PacifiCorp has explained in prior TAMs, determining whether a coal unit can be shut down requires consideration of more than just economics. PacifiCorp also considers transmission congestion, voltage support, and other operational issues such as maintaining adequate system inertia.

For these reasons, in its actual, prudent operations, the Company will typically cycle a coal unit to its minimum when needed but will not entirely shut it down. As discussed above, the purpose of the TAM is to model actual operations. Removing the "must run" setting departs from actual operations and makes Aurora's optimized unit dispatch unrealistic.

Q. Please explain what emergency purchases are and how they relate to reliability?

A. In Aurora, emergency purchases take place either when the model has no other method to satisfy the load obligation because of the modeling constraints, or in rare cases when the emergency purchase price is less than the cost of an alternative solution. In Aurora, emergency purchases are priced at 125 percent of market and are available to purchase at load. These are conservative assumptions that are unlikely to reflect actual emergency purchase needs from either a cost or availability (market liquidity) perspective. Emergency purchases help the model meet its reliability target to ensure there is no unserved load. As emergency purchases increase, it reflects reliability issues that are inconsistent with a feasible operational plan. Emergency purchases are simply a modeling construct that allows Aurora to solve in the absence of economically superior alternatives, or in instances where the system resources are insufficient to balance generation and load. In other words, emergency purchases are a modeling solution and do not have an equivalent in actual operations. In the event of an actual emergency, PacifiCorp does not have unlimited energy available to purchase to meet load at a reasonable price as Aurora assumes.

Q. In the 2022 TAM Order, the Commission requested a follow-up on the economic cycling study[19] to address whether the "economic cycling of units, with reliability considerations factored in, creates savings for customers." Has PacifiCorp completed different Aurora runs using different methodologies of economic cycling?

A. Yes; Aurora has many features that enable PacifiCorp to consider a wider variety of economic cycling scenarios in the NPC forecast, while still modeling many of the operational constraints that PacifiCorp faces. Given the importance of this issue, the Company elected to complete additional cycling scenarios aimed at exploring the potential range of impacts on the NPC forecasts based on different assumptions regarding unit cycling. Table 4 below provides a summary of the assumptions contained in each scenario as well as the related NPC forecast. The results of these scenarios aid in confirming the Company's belief that NPC are the lowest when coal resources are run with the "must run" setting turned on and provide the maximum economic and reliability benefit to customers.

Q. The purpose of this study was to address whether the "economic cycling of units, with reliability considerations factored in, creates savings for customers."[20] What was the result of this study?

A. In every coal-cycling that PacifiCorp studied, NPC increased, and reliability decreased.

[19] Order No. 21-379 at 9.
[20] Order No. 21-379 at 9.

Table 4: Must Run Scenario Summary

Scenario	Must Run Status	Scenario Details	Total Company NPC Value $ (in billions)	NPC Difference to Must Run scenario $ (in billions)
Must Run (S01)	Turned ON		1.679	
Coal Cycling (S02) (Base TAM Case)	Turned OFF	Min Up and Down time set to 48 hours	1.684	0.005
Coal Cycling (S03)	Turned OFF	Coal units cycled only in Spring and Fall	1.685	0.006
Coal Cycling (S04)	Turned OFF	Minimum Up and Down time set to 168 hours	2.358	0.679

Q. Please explain the settings in Aurora for Coal Cycling (S02) scenario and what the adjustment of those settings illustrates.

A. This scenario was the base case used in this filing. It was run with coal resources being allowed to economically cycle while the minimum up time for all PacifiCorp operated coal resources was set to 48 hours. This reduction of minimum up time helps Aurora optimize better as it does not need to find extended periods to ensure that the units are online to recover their start-up costs.

Q. Please compare the Coal Cycling (S02) to actual operations and actual reliability constraints. Please comment on its impact to NPC.

A. Operationally, PacifiCorp has coal resources with properties that are significantly different as a part of its resource fleet. Setting the minimum up time to 48 hours for PacifiCorp operated plants is not reflective of its actual operational minimum up times of 168 hours (this scenario is examined in S04). Imposing this constraint, however, provides Aurora the flexibility to identify additional periods where the resources can be economically shut down. The NPC is $1.684 billion and is a $5 million increase over the Must Run case (S01) which has all the coal resources set to Must Run. Table 5 shows the changes to the generation levels when coal cycling is turned on in Scenario S02. The emergency purchases increase by 23 GWh due to reduced gas generation.

Table 5: S02 Generation Changes

Description	Energy Impact (GWh)
Coal Generation	1,994
Gas Generation	(2,043)
Balancing Purchases	164
Balancing Sales	138
Emergency Purchases	23

Q. Why does coal generation increase and natural gas generation decrease?

A. When "must run" is turned on, lower cost coal-fueled resources are economically dispatched between their minimum and maximum generation capabilities. With the exception of outages, these resources are always online and able to serve load and/or provide reserves to the system. The higher-priced natural gas resources are then cycled as needed and can also serve load and/or provide reserves to the system.

When the "must run" setting for coal-fueled resources is turned off, it simultaneously introduces additional flexibility and additional complexity into the model. The complexity results from minimum up and down times and startup costs becoming binding constraints. In this scenario, higher priced coal resources are cycled offline, while lower priced coal resources increase their generation to serve load. This allows the model to reduce the reserve provisions from lower priced coal resources to higher priced coal resources. Additionally, natural gas resources (more expensive due to the price of gas) are cycled less and therefore provide less generation and reserves to the system. Finally, the overall generation to meet load is reduced so the model must fill that need at market.

Q. How does this compare to PacifiCorp's actual operations?

A. The model is showing that by operating the coal units between their minimum and maximum generation levels they are able to augment VERS and provide reserves to the system to lower NPC, consistent with the Company's operational practices. However, when "must-run" is turned off in the model, less thermal generation is available to meet both load and reserves, which results in the model having greater difficulty meeting load and reserves.

Q. Are the following scenarios compared against the TAM base case scenario (S02)?

A. Yes.

Q. Please explain the settings in Aurora for Coal Cycling (S03) scenario and what the adjustment of those settings illustrates.

A. This scenario was run with coal resources being allowed to economically cycle during the spring and fall seasons which represent non-peak load scenarios for the Company. The minimum up and down time for all PacifiCorp owned coal resources was set to 168 hours. The coal resources that PacifiCorp is a part owner of were set to Must Run. This helps Aurora optimize better as it does not need to find extended periods throughout the year to ensure that the units are online to recover their start-up costs.

Q. Please compare the Coal Cycling (S03) to actual operations and actual reliability constraints. Please comment on its impact to NPC.

A. Since spring and fall seasons are not peak load seasons, the model elects to economically cycle the coal resources. This results in the model significantly backing down PacifiCorp's natural gas generation. Operationally, PacifiCorp-owned coal resources have minimum up and down times that are reflected in this scenario. However, natural gas generation can be cycled in every hour. Therefore, Aurora loses some of its flexibility to find increased periods wherein the resources can be economically shut down. The decreased natural gas generation is offset by increased coal generation and market purchases, but generation from VERs is curtailed due to operational constraints that exist for thermal resources.

While allowing units to only cycle in the spring and fall could be hypothesized to better reflect operational conditions, because they are not peak load seasons for the Company, the result represents an unrealistic picture of resource dispatch when compared to the Company's actual operations. PacifiCorp would not curtail VERs to increase coal dispatch or market purchases. Additionally, there is a substantial increase in emergency purchases which is not reflective of reality.

Q. How does this scenario compare to the TAM base case?

A. Since spring and fall seasons are not peak load seasons, the model elects to economically cycle the coal resources. The results from the scenario model run indicates a total NPC of $1.685 billion, representing a $6 million increase over the Must Run case (S01). Table 6 shows the changes to the generation levels when coal cycling is turned on in scenario S03 when compared to base case scenario (S02). The emergency purchases increase by 197 GWh due to reduced gas generation and VER generation curtailment of 65 GWh. This results in an unrealistic dispatch of resources and is not representative of PacifiCorp's actual operations.

Table 6: S03 Generation Changes

Description	Energy Impact (GWh)
Coal Generation	31
Gas Generation	(331)
Balancing Purchases	119
Balancing Sales	(55)
Curtailed VER Generation	65
Emergency Purchases	197

Q. Please explain the settings in Aurora for Coal Cycling (S04) scenario and what the adjustment of those settings illustrates.

A. This scenario assumes that coal resources are allowed to economically cycle during the year. The minimum up and down time for all coal resources was set to 168 hours. These settings are reflective of PacifiCorp's operational standards. Among the scenarios noted here, S04 is not only the most closely aligned with the Company's operational realities but is also the most complex optimization problem that Aurora solves to produce the least cost solution. Due to the minimum up and down times being set to 168 hours, the model finds it significantly difficult to find periods in a year wherein it could economically cycle coal resources while meeting operational reliability standards.

Q. Please compare the Coal Cycling (S04) to actual operations and actual reliability constraints. Please comment on its impact to NPC.

A. The modeled operational constraints of minimum up and down times are reflective of PacifiCorp's actual operational constraints. This results in the model significantly backing down PacifiCorp's natural gas and coal generation. However, backing down of coal generation is not reflective of PacifiCorp's operation of these resources. For many years, PacifiCorp has been lowering the minimum operating levels for many of these coal resources to increase their flexibility and responsiveness to economic cycling.

Loss of modeling flexibility coupled with significant backing down of thermal generation leads Aurora to increase its emergency purchases to prevent the scenario of unserved load. Similar to the previous scenario, the decreased thermal generation is offset by increased market purchases, but generation from VERs is curtailed due to operational constraints that exist for thermal resources.

In the Must Run scenario, the operational constraints such as minimum up and down times, Minimum Operational Capacity, etc. are not binding due to the model never turning these units off (except for planned outages). However, in this scenario, due to the aforementioned complexity, these constraints are binding. This is similar to operational difficulties that would be faced by the Company if it were to actually operate in this manner.

While economic cycling could be hypothesized to better reflect operational conditions, the actual result is an unrealistic dispatch of resources. PacifiCorp would not curtail VERs to increase market purchases, especially since purchases tend to be priced higher due to the scarcity pricing component. Additionally, the significant increase in emergency purchases indicates that this would be a scenario that would face extreme reliability issues.

Q. How does this scenario compare to the TAM base case?

The NPC is $2.358 billion and is a $679 million increase over the Must Run case (S01). Table 7 shows the changes to the generation levels when coal cycling is turned on in scenario S04 when compared to base case scenario (S02). The emergency purchases increase by 5,430 GWh due to reduced natural gas generation and VER generation curtailment of 904 GWh. As seen below, the model increases its purchases, mainly emergency purchases, to cover for its displaced thermal and VERs generation.

Table 7: S04 Generation Changes

Description	Energy Impact (GWh)
Coal Generation	(2,501)
Gas Generation	(1,114)
Balancing Purchases	2,092
Balancing Sales	(585)
Curtailed VER Generation	909
Emergency Purchases	5,430

Q. Does removal of the "must run" provide forecasts that are in line with operational realities?

A. No. The removal of the "must run" setting reflects an artificial reality where nearly all of PacifiCorp's units could be economically cycled at any time. PacifiCorp does not and could not operate its coal units in this fashion. Allowing Aurora to increase economic cycling exacerbates the inherent differences between system optimization modeled in Aurora and system optimization that can be realized in actual operations.

PacifiCorp has made significant operational gains in reducing the minimum operating levels for coal plants. This means that instead of entirely shutting down a unit, the Company instead dispatches the unit to its minimum operating levels.

X. REQUESTED INFORMATION ON QUALIFYING FACILITIES

Q. In the 2022 TAM Order, the Commission requested additional information on PacifiCorp's QF forecast including providing updated data and addressing why it has continued to over-forecast QFs in recent years.[21] Is the requested information available?

A. Not yet. Finalized information to update the table identified in the Commission's order will not be available until PacifiCorp files the PCAM in Oregon on May 15, 2022. PacifiCorp will provide the updated information in its rebuttal filing.

Q. Has PacifiCorp been investigating what is causing the over forecast of QFs?

A. Yes; PacifiCorp has been investigating the cause of the over forecast and preliminary analysis indicates that the variance may be associated with the forecasts for small Oregon QFs. PacifiCorp is continuing to examine the issue and will present a more thorough analysis along with the final data in its rebuttal filing.

XI. PTCS AND NPC BENEFITS OF WIND PROJECTS

Q. Have all the NPC and PTC benefits of the Energy Vision 2020 Wind Projects been included in the 2023 TAM?

A. Yes. The NPC and PTC benefits of all new wind projects are included in the 2023 TAM. These include the Energy Vision 2020 Wind Projects, which are 1,150 MW of new wind assets at TB Flats, Cedar Springs II, Ekola Flats, and a power purchase agreement (PPA), Cedar Springs I. Associated with the Energy Vision 2020 Wind Projects is a new 140-mile 500 kilovolt transmission line between the Aeolus substation and the Jim Bridger power plant to allow the interconnection of these

[21] Order No. 21-379 at 38.

facilities into PacifiCorp's transmission system. In addition to the Energy Vision 2020 Projects, the TAM includes two other wind projects: the 240 MW Pryor Mountain wind project and the 133.3 MW Cedar Springs III PPA.

Q. Please describe the treatment of renewable energy PTCs in the 2023 TAM.

A. The 2023 TAM includes changes in projected levels of PTCs. Confidential Exhibit PAC/106 shows the forecast level of PTCs for 2023 compared to the level of PTCs established in the 2022 TAM. The forecast value of Oregon-allocated PTCs for the 2023 test period is approximately $70.2 million, which is higher than the $68.4 million included in the 2022 TAM, resulting in a decrease to the 2023 TAM of $1.8 million.

Q. How are PTCs calculated for the 2023 TAM?

A. The PTC provides a federal income tax credit for the first 10 years of a renewable energy facility's operation. The PTC is calculated by multiplying the qualifying generation by the current PTC rate of 2.7 cents per kilowatt-hour and then grossing-up for taxes.

Q. Please describe the capacity, capacity factors, generation and PTCs for the wind projects in the 2023 TAM.

A. As seen in Confidential Table 8 below, on a total-company basis, the total Company-owned wind capacity is 2,155 MW. Total forecast generation on a total-company basis is 7,573,819 MWh. The total tax-adjusted PTCs on an Oregon-allocated basis are $70.2 million.

Confidential Table 8: Company-Owned Wind Projects Generation and PTC Data

	Total Company				Oregon Allocated		
Plant Name	PTC Value	LGIA Capacity (MW)	LGIA Capacity Factor	Generation (MWH)	Factors CY 2023	CY 2022 Final Filing	Revenue Requirement
Glenrock	[redacted]	99.0	[redacted]	[redacted]	26.070%	[redacted]	[redacted]
Glenrock III	[redacted]	39.0	[redacted]	[redacted]	26.070%	[redacted]	[redacted]
Goodnoe Hills	[redacted]	94.0	[redacted]	[redacted]	26.070%	[redacted]	[redacted]
High Plains Wind	[redacted]	99.0	[redacted]	[redacted]	26.070%	[redacted]	[redacted]
Leaning Juniper 1	[redacted]	100.5	[redacted]	[redacted]	26.070%	[redacted]	[redacted]
Marengo	[redacted]	156.0	[redacted]	[redacted]	26.070%	[redacted]	[redacted]
Marengo II	[redacted]	78.0	[redacted]	[redacted]	26.070%	[redacted]	[redacted]
McFadden Ridge	[redacted]	28.5	[redacted]	[redacted]	26.070%	[redacted]	[redacted]
Seven Mile	[redacted]	99.0	[redacted]	[redacted]	26.070%	[redacted]	[redacted]
Seven Mile II	[redacted]	19.5	[redacted]	[redacted]	26.070%	[redacted]	[redacted]
Dunlap I Wind	[redacted]	111.0	[redacted]	[redacted]	26.070%	[redacted]	[redacted]
Foote Creek I Wind	[redacted]	41.4	[redacted]	[redacted]	26.070%	[redacted]	[redacted]
Pryor Mountain Wind	[redacted]	239.8	[redacted]	[redacted]	26.070%	[redacted]	[redacted]
Cedar Springs Wind II	[redacted]	200.0	[redacted]	[redacted]	26.070%	[redacted]	[redacted]
Ekola Flats Wind	[redacted]	250.0	[redacted]	[redacted]	26.070%	[redacted]	[redacted]
TB Flats Wind	[redacted]	247.3	[redacted]	[redacted]	26.070%	[redacted]	[redacted]
TB Flats Wind II	[redacted]	252.7	[redacted]	[redacted]	26.070%	[redacted]	[redacted]
Total Production Tax Credit	$ 203,036,306	2,154.7		7,573,819		$ 51,581,197	$ 70,189,462

Note 1 - Revenue Requirement represents the PTC amount grossed up for the tax rate.

Q. In addition to the PTCs, please describe and quantify any other NPC benefits from the new wind projects.

A. The addition of the new wind projects described above (TB Flats, Cedar Springs I, II and III, Ekola Flats, and Pryor Mountain) bring substantial amounts of low-cost generation onto PacifiCorp's system, allowing for the displacement of other higher-cost forms of generation. The forecast total-company NPC benefit impact of the new wind resources in 2023 is approximately $222 million. This result is consistent with the Company's past studies that consistently show NPC reductions as a result of the projects, primarily owing to the lower production costs.

Q. Please explain, for the 2023 TAM, "whether the wind displaces PacifiCorp's higher cost generation, or excess wind output is forecast to be sold to the market with revenues that benefit customers[.]"[22]

A. When PacifiCorp removed the new wind from the NPC forecast in Aurora, the largest impact was an increase in coal generation. PacifiCorp's forecast also resulted in significantly increased system balancing purchases. This demonstrates that the wind generation is mostly displacing higher cost resources (coal generation and market purchases) with zero-fuel cost resources. The total-company magnitude of these changes, on both a cost and energy basis, is displayed in Table 9 below.

Table 9: Impact of the Removal of New Wind Resources

Description	Cost Impact ($millions)	Energy Impact (GWh)
Removal of Resources	$ (20.6)	(5,345)
Coal Generation	$ 20.8	1,118
Gas Generation	$ 51.4	1,832
Balancing Purchases	$ 136.7	1,941
Balancing Sales	$ 33.4	454
Total	$ 221.6	-

The actual resources that replace the removed wind projects depend on the prevailing spot market economics and the state of other constraints in the model during the hour being optimized. Without the new wind projects, PacifiCorp had approximately 1,118 GWh of increased coal generation resulting in $20.8 million in increased total-company NPC. Additionally, the new wind projects avoided 1,941 GWh of system balancing purchases at a cost of $136.7 million. The contribution of the new wind projects reduces NPC by nearly $222 million total company, avoids significant

[22] *In the Matter of PacifiCorp, d/b/a Pacific Power, 2021 Transition Adjustment Mechanism*, Docket No. UE 375, Order No. 20-392 at 9 (Oct. 30, 2020).

market purchases, and reduces coal generation for 2023. This only reflects one year of NPC benefits for customers and is incremental to the significant PTC benefits associated with these new resources.

XII. CONSUMER OPT-OUT CHARGE

Q. What is the Consumer Opt-Out Charge?

A. The Consumer Opt-Out Charge is a transition adjustment applicable to the Company's five-year direct access program and is intended to recover transition costs incurred during years six through 10 following the departure of the direct access load. The Commission approved the Consumer Opt-Out Charge in docket UE 267, after finding that PacifiCorp will experience transition costs for 10 years and approved the Consumer Opt-Out Charge to recover the Company's fixed generation costs in years six through 10.[23] As part of a provision in the stipulation for the 2020 TAM, PacifiCorp agreed to not apply inflation to the fixed generation costs in years six through 10.[24]

Q. How does the Consumer Opt-Out Charge operate together with Schedule 200, the rate schedule that collects fixed generation costs?

A. In the first five years after the direct access customer elects to leave, the customer pays the actual Schedule 200 costs as those costs change during that five-year period. If PacifiCorp adds incremental generation during those five years and those costs flow into Schedule 200, the direct access customer pays those costs.

[23] *Re PacifiCorp's Transition Adjustment, Five-Year Cost of Service Opt-Out*, Docket No. UE 267, Order No. 15-060 at 6-7 (Feb. 24, 2016).
[24] *In the Matter of PacifiCorp d/b/a Pacific Power, 2020 Transition Adjustment Mechanism*, Docket No. UE 356, Order No. 19-351, Appendix A at 10 (Oct. 30, 2019).

The Consumer Opt-Out Charge accounts for forecast Schedule 200 costs for years six through 10. To calculate the Consumer Opt-Out Charge, PacifiCorp first takes the Schedule 200 costs in effect at the time the customer departs and escalates those costs for five years, using an inflation escalator. The departing customer does not pay these escalated Schedule 200 costs for years one through five because the customer is paying the actual Schedule 200 costs for the first five years.

PacifiCorp takes the escalated Schedule 200 cost for year five and holds that cost flat through year 10 to develop a forecast of Schedule 200 costs for years six through 10. The Consumer Opt-Out Charge is then calculated by taking the forecast Schedule 200 costs and reducing them back to calculate a levelized payment made in years one through five. Together, through the payment of Schedule 200 and the Consumer Opt-Out Charge, departing customers pay PacifiCorp's fixed generation costs for 10 years (offset by the value of freed-up energy).

Q. Is the calculation of the Consumer Opt-Out Charge in the 2023 TAM consistent with the requirements from the commission's order in the 2022 TAM?[25]

A. Yes.

XIII. COMPANY SUPPLY SERVICE ACCESS CHARGE

Q. What is the Company Supply Service Access Charge?

A. If a new customer elects new load direct access and then subsequently switches to standard offer or cost-based service, resulting in an increase to rates for existing cost-of-service customers of more than 0.5 percent, the consumer electing to switch to standard offer service or cost-based service will be subject to a four-year forward

[25] Order No. 21-379 at 42.

looking rate adder, the Company Supply Service Access Charge. The 0.5 percent assessment is a reasonable threshold for the Company Supply Service Access Charge that represents a material and significant impact to customers and was acknowledged by the Commission at a public meeting on February 26, 2019.[26]

Q. How is the Company Supply Service Access Charge calculated?

A. The Company Supply Service Access Charge is calculated as the incremental difference between the four-year levelized cost of capacity that is calculated for avoided cost and the fixed generation costs, Schedule 200. This calculation fairly assigns the new load direct access consumer that is switching to cost-of-service the additional fixed cost associated with the Company's obligation to serve that consumer less the additional recovery that will be received from that consumer for existing fixed generation in rates. The levelized cost of capacity for the upcoming four years is currently less than the fixed generation costs contained in Schedule 200 and therefore the Company Supply Service Access Charge is $0/MWh.

XIV. COMPLIANCE WITH TAM GUIDELINES

Q. Did the Company prepare this filing in accordance with the TAM Guidelines adopted by Order No. 09-274, as clarified and amended in later orders?

A. Yes. The Company has complied with the TAM Guidelines applicable to the initial filing in a TAM.

Q. Does this filing include updates to all NPC components identified in Attachment A to the TAM Guidelines?

A. Yes.

[26] *PacifiCorp Schedule 193 New Large Load Direct Access Program*, Docket No. ADV-900, Advice No. 18-010, acknowledged Feb. 26, 2019.

Q. What workpapers did the Company provide with this filing?

A. In compliance with Attachment B to the TAM Guidelines, the Company provided access to the Aurora model and workpapers concurrently with this initial filing. Specifically, the Company provided the NPC report workbook and the Aurora project report.

Q. Did PacifiCorp provide a step-log of model and input changes describing changes to the Company's modeling or inputs that are not considered a standard annual update?

A. Yes. The Company has provided the step-log as Exhibit PAC/107.

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. UE 400
Exhibit PAC/101
Witness: Michael G. Wilding

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Michael G. Wilding

Oregon-Allocated Net Power Costs

March 2022

PacifiCorp
CY 2023 TAM
Initial Filing

Line no		ACCT.	Total Company: UE-390 CY 2022 - Final Update	Total Company: TAM CY 2023 - Initial Filing	Factor	Factors CY 2022	Factors CY 2023	Oregon Allocated: UE-390 CY 2022 - Final Update	Oregon Allocated: TAM CY 2023 - Initial Filing
1	**Sales for Resale**								
2	Existing Firm PPL	447	8,349,236	6,189,133	SG	26.482%	26.070%	2,211,009	1,613,528
3	Existing Firm UPL	447	-	-	SG	26.482%	26.070%	-	-
4	Post-Merger Firm	447	599,533,731	349,419,847	SG	26.482%	26.070%	158,765,990	91,094,949
5	Non-Firm	447	-	-	SE	25.369%	25.068%	-	-
6	**Total Sales for Resale**		607,882,968	355,608,980				160,976,999	92,708,477
7									
8	**Purchased Power**								
9	Existing Firm Demand PPL	555	34,174,104	8,295,068	SG	26.482%	26.070%	9,049,842	2,162,553
10	Existing Firm Demand UPL	555	12,291,919	11,456,377	SG	26.482%	26.070%	3,255,094	2,986,717
11	Existing Firm Energy	555	107,897,352	44,724,911	SE	25.369%	25.068%	27,372,866	11,211,701
12	Post-merger Firm	555	717,644,565	885,848,099	SG	26.482%	26.070%	190,043,601	230,943,629
13	Secondary Purchases	555	-	-	SE	25.369%	25.068%	-	-
14	Other Generation Expense	555	-	-	SG	26.482%	26.070%	-	-
15	**Total Purchased Power**		872,007,940	950,324,455				229,721,403	247,304,600
16									
17	**Wheeling Expense**								
18	Existing Firm PPL	565	23,937,361	23,886,724	SG	26.482%	26.070%	6,338,991	6,227,351
19	Existing Firm UPL	565	-	-	SG	26.482%	26.070%	-	-
20	Post-merger Firm	565	115,028,330	124,541,723	SG	26.482%	26.070%	30,461,316	32,468,453
21	Non-Firm	565	12,043,742	12,388,361	SE	25.369%	25.068%	3,055,420	3,105,531
22	**Total Wheeling Expense**		151,009,433	160,816,807				39,855,727	41,801,335
23									
24	**Fuel Expense**								
25	Fuel Consumed - Coal	501	647,001,159	599,969,137	SE	25.369%	25.068%	164,140,043	150,401,074
26	Fuel Consumed - Coal (Cholla)	501	-	-	SE	25.369%	25.068%	-	-
27	Fuel Consumed - Gas	501	7,098,310	13,117,319	SE	25.369%	25.068%	1,800,796	3,288,267
28	Natural Gas Consumed	547	292,158,097	301,360,345	SE	25.369%	25.068%	74,118,635	75,545,418
29	Simple Cycle Comb. Turbines	547	4,046,151	9,466,735	SE	25.369%	25.068%	1,026,483	2,373,134
30	Steam from Other Sources	503	3,966,594	4,484,106	SE	25.369%	25.068%	1,006,299	1,124,082
31	**Total Fuel Expense**		954,270,311	928,397,642				242,092,255	232,731,975
32									
33	TAM Settlement Adjustment		-	-		As Settled		-	-
34									
35	**Net Power Cost (Per Aurora)**		1,369,404,716	1,683,929,924				350,692,386	429,129,432
36									
37	Oregon Situs NPC Adustments		(167,224)	(430,221)	OR	100.000%	100.000%	(167,224)	(430,221)
38	**Total NPC Net of Adjustments**		1,369,237,492	1,683,499,703				350,525,162	428,699,211
39									
40	Production Tax Credit (PTC)		(258,284,914)	(269,231,073)	SG	26.482%	26.070%	(68,397,920)	(70,189,462)
41	**Total TAM Net of Adjustments**		1,110,952,578	1,414,268,630				282,127,243	358,509,750
42									
43								Increase Absent Load Change	76,382,507
44									
45			Oregon-allocated NPC (incl. PTC) Baseline in Rates from UE-390					$282,127,243	
46			$ Change due to load variance from UE-390 forecast					6,408,529	
47			2023 Recovery of NPC (incl. PTC) in Rates					$288,535,772	
48									
49								**Increase Including Load Change**	**$ 69,973,978**
50									
51								Add Other Revenue Change	-
52									
53								**Total TAM Increase/(Decrease)**	**$ 69,973,978**

Docket No. UE 400
Exhibit PAC/102
Witness: Michael G. Wilding

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Michael G. Wilding

Net Power Costs Report

March 2022

Exhibit PAC 102 - ORTAM23 Net Power Costs

$

	Total	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23
Special Sales For Resale													
Long Term Firm Sales													
Black Hills	$ 6,189,133	$ 546,792	$ 482,693	$ 568,895	$ 524,605	$ 366,665	$ 427,988	$ 567,428	$ 571,880	$ 532,928	$ 512,895	$ 518,460	$ 567,906
BPA Wind	-	-	-	-	-	-	-	-	-	-	-	-	-
East Area Sales (WCA S	-	-	-	-	-	-	-	-	-	-	-	-	-
Hurricane Sale	6,561	547	547	547	547	547	547	547	547	547	547	547	547
LADWP (IPP Layoff)	-	-	-	-	-	-	-	-	-	-	-	-	-
Leaning Juniper Revenu	187,946	12,405	11,734	15,990	8,008	9,357	9,903	31,365	32,259	22,061	12,519	10,156	12,190
PSCo Sale	13,112,861	894,040	824,640	910,380	653,600	677,440	881,920	1,839,220	2,216,455	2,092,288	719,881	700,412	702,586
SMUD	-	-	-	-	-	-	-	-	-	-	-	-	-
UMPA II s45631	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Long Term Firm Sales	19,496,501	1,453,784	1,319,614	1,495,812	1,186,760	1,054,009	1,320,357	2,438,559	2,821,140	2,647,823	1,245,841	1,229,574	1,283,228
Short Term Firm Sales													
COB	-	-	-	-	-	-	-	-	-	-	-	-	-
Colorado	-	-	-	-	-	-	-	-	-	-	-	-	-
Four Corners	-	-	-	-	-	-	-	-	-	-	-	-	-
Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-
Mead	-	-	-	-	-	-	-	-	-	-	-	-	-
Mid Columbia	-	-	-	-	-	-	-	-	-	-	-	-	-
Mona	-	-	-	-	-	-	-	-	-	-	-	-	-
NOB	-	-	-	-	-	-	-	-	-	-	-	-	-
Palo Verde	-	-	-	-	-	-	-	-	-	-	-	-	-
SP15	-	-	-	-	-	-	-	-	-	-	-	-	-
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	-	-	-	-	-	-	-	-	-	-	-	-
West Main	-	-	-	-	-	-	-	-	-	-	-	-	-
Wyoming	-	-	-	-	-	-	-	-	-	-	-	-	-
Electric Swaps Sales	-	-	-	-	-	-	-	-	-	-	-	-	-
STF Trading Margin	-	-	-	-	-	-	-	-	-	-	-	-	-
STF Index Trades	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Short Term Firm Sales	-	-	-	-	-	-	-	-	-	-	-	-	-
System Balancing Sales													
COB	69,088,736	6,708,380	6,001,624	4,273,258	2,798,151	3,721,591	3,293,685	7,612,917	5,511,989	6,237,408	7,313,014	8,110,549	7,506,170
Four Corners	74,680,419	12,726,528	6,942,333	7,134,654	4,688,412	4,159,264	4,951,990	6,834,865	3,443,753	6,317,325	9,979,790	5,159,563	2,341,941
Mead	45,041,971	3,884,173	2,017,522	3,272,247	1,985,559	2,287,851	3,802,519	7,058,335	6,722,132	6,193,224	3,831,141	2,282,469	1,704,800
Mid Columbia	104,316,781	5,995,320	2,724,661	597,927	2,918,035	2,612,383	4,428,787	15,429,817	20,518,422	14,361,668	9,553,708	10,612,718	14,563,334
Mona	30,560,380	5,442,274	2,937,880	2,207,194	1,022,674	819,963	1,708,716	2,405,263	1,851,067	4,383,247	4,037,108	2,171,375	1,573,618
NOB	10,184,629	2,379	896,469	157,868	73,072	-	28,922	1,759,936	2,088,608	2,031,985	977,073	605,194	1,563,122
Palo Verde	1,657,391	247,896	136,209	157,760	147,024	172,869	98,447	620,567	77,268	592,659	128,141	(290,601)	(430,850)
Palo Verde - PSCO Exch	-	-	-	-	-	-	-	-	-	-	-	-	-
Trapped Energy	582,174	441	-	-	1,048	5,317	-	252,540	75,678	57,361	56,561	50,118	83,111
Total System Balancing Sales	336,112,479	35,007,391	21,656,698	17,800,908	13,633,975	13,779,239	18,313,066	41,974,239	40,288,917	40,174,876	35,876,536	28,701,386	28,905,246
Total Special Sales For Resale	355,608,980	36,461,175	22,976,313	19,296,720	14,820,735	14,833,248	19,633,423	44,412,799	43,110,057	42,822,699	37,122,378	29,930,960	30,188,474

Purchased Power & Net Interchange

Long Term Firm Purchases

APS Supplemental	-	-	-	-	-	-	-	-	-	-	-	-	-
Avoided Cost Resource	-	-	-	-	-	-	-	-	-	-	-	-	-
Appaloosa 1A Solar	1,565,395	-	-	-	-	-	-	-	-	-	663,577	493,121	408,698
Appaloosa 1B Solar	1,043,597	-	-	-	-	-	-	-	-	-	442,384	328,747	272,465
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	631,272	565,348	564,366	445,199	628,829	828,668	811,823	1,018,881
Combine Hills Wind	5,518,680	391,582	474,473	577,295	573,395	489,246	422,189	470,712	401,146	374,581	392,359	478,127	473,577
Cove Mountain Solar	3,833,283	183,848	193,154	336,688	366,527	421,871	453,707	440,109	416,435	357,107	287,471	206,551	169,814
Cove Mountain Solar II	9,492,755	455,531	478,588	834,231	908,164	1,045,294	1,124,175	1,090,482	1,031,823	884,823	712,282	508,940	418,421
Deseret Purchase	35,399,601	2,949,508	2,894,441	2,982,548	2,654,901	2,814,594	2,616,354	3,142,241	3,142,241	3,109,201	3,135,358	2,931,611	3,026,601
Douglas PUD Settlement	-	-	-	-	-	-	-	-	-	-	-	-	-
Eagle Mountain - UAMPS	-	-	-	-	-	-	-	-	-	-	-	-	-
Elektron Solar 20 yr	797,568	33,497	43,407	67,263	75,303	88,503	94,444	98,031	89,830	77,236	62,736	38,625	28,693
Elektron Solar 25yr	5,433,412	228,197	295,697	458,224	513,009	602,940	643,391	667,840	611,965	526,177	427,379	263,127	195,467
Gemstate	1,145,216	143,152	143,152	143,152	143,152	143,152	143,152	143,152	143,152	-	-	-	-
Georgia-Pacific Camas	-	-	-	-	-	-	-	-	-	-	-	-	-
Graphite Solar	6,272,497	313,766	355,437	561,331	616,028	690,923	708,977	691,500	646,870	579,734	483,379	357,284	267,268
Hermiston Purchase	-	-	-	-	-	-	-	-	-	-	-	-	-
Horseshoe Solar	5,348,701	234,892	291,605	439,979	498,295	594,079	657,771	646,513	612,605	509,566	409,414	253,049	200,935
Hunter Solar	7,051,153	371,168	420,781	641,039	669,033	762,896	789,454	750,512	705,507	657,834	561,379	398,161	323,388
Hurricane Purchase	185,380	15,448	15,448	15,448	15,448	15,448	15,448	15,448	15,448	15,448	15,448	15,448	15,448
IPP Purchase	-	-	-	-	-	-	-	-	-	-	-	-	-
MagCorp	-	-	-	-	-	-	-	-	-	-	-	-	-
MagCorp Reserves	3,837,570	320,800	312,780	316,790	324,810	316,790	324,810	328,820	312,780	308,770	296,740	344,860	328,820
Milican Solar	2,814,730	92,708	141,477	216,779	272,858	323,854	352,508	396,975	350,779	282,304	184,848	118,394	81,245
Milford Solar	6,975,304	353,274	406,820	600,085	667,481	784,725	827,371	736,808	709,314	661,660	533,619	388,227	305,919
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	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	1,875,216	63,645	97,125	144,022	181,280	215,160	234,197	263,740	233,048	187,556	122,808	78,658	53,977
Rock River Wind	-	-	-	-	-	-	-	-	-	-	-	-	-
Rocket Solar	5,701,664	259,213	312,609	471,485	534,316	624,413	701,716	719,326	650,885	547,234	416,143	254,235	210,089
Sigurd Solar	5,917,296	309,554	345,619	509,742	556,548	639,667	703,042	653,634	599,181	559,401	453,931	319,006	267,971
Skysol Solar	9,192,400	-	-	698,731	756,489	964,767	1,278,104	1,603,572	1,541,676	1,061,102	626,170	344,706	317,083
Small Purchases east	14,288	1,173	1,213	1,172	1,172	1,233	1,203	1,226	1,202	1,153	1,157	1,209	1,176
Small Purchases west	-	-	-	-	-	-	-	-	-	-	-	-	-
Soda Lake Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-
Three Buttes Wind	20,712,516	2,790,662	1,806,920	2,141,628	1,609,251	1,428,678	1,205,304	804,843	950,802	1,185,464	1,741,196	2,346,698	2,701,069
Top of the World Wind	40,663,534	5,436,528	3,612,747	4,245,733	3,266,227	2,910,525	2,398,843	1,719,857	1,873,298	2,296,246	3,519,349	4,486,125	4,898,057
Tri-State Purchase	-	-	-	-	-	-	-	-	-	-	-	-	-
West Valley Toll	-	-	-	-	-	-	-	-	-	-	-	-	-
Wolverine Creek Wind	10,515,791	779,175	910,409	1,160,071	1,067,046	809,392	861,546	685,959	655,309	770,017	851,206	983,388	982,273
UT Solar Adjustment	(15,944,747)	(541,029)	(605,122)	(1,169,630)	(1,299,093)	(1,513,549)	(1,550,024)	(2,149,849)	(2,011,881)	(1,693,248)	(1,394,180)	(1,147,788)	(869,353)
Long Term Firm Purchases Total	223,878,751	19,884,151	17,199,765	20,534,000	19,083,501	18,960,414	18,640,627	17,552,316	17,038,320	17,039,407	19,189,071	18,994,390	19,762,789
Seasonal Purchased Power													
Constellation 2013-2016	-	-	-	-	-	-	-	-	-	-	-	-	-

Seasonal Purchased Power Total	-	-	-	-	-	-	-	-	-	-	-	-	-
Qualifying Facilities													
QF California	1,946,289	167,233	177,402	211,319	215,259	201,314	163,668	138,774	134,129	127,044	131,560	129,839	148,750
QF Idaho	6,850,173	494,510	479,853	509,733	517,179	544,059	596,469	691,075	629,048	563,892	595,407	562,306	666,645
QF Oregon	45,280,776	2,280,028	2,701,451	3,701,484	4,766,735	5,087,268	5,391,921	5,217,910	4,967,318	4,138,961	3,032,462	2,030,870	1,964,367
QF Utah	12,465,631	852,212	891,894	1,078,846	1,105,629	1,216,055	1,236,570	1,149,183	1,147,019	1,075,785	1,012,884	890,675	808,880
QF Washington	214,683	-	-	-	5,120	18,598	51,806	58,266	53,533	25,617	1,742	-	-
QF Wyoming	83,693	10,082	8,462	10,115	6,274	5,040	3,055	8,330	7,518	3,297	5,239	6,353	9,929
Biomass One QF	17,682,382	1,579,705	1,323,820	1,494,894	1,660,178	1,717,172	1,669,902	1,492,952	1,480,105	1,422,906	1,521,916	1,485,941	832,891
Boswell Wind I QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Boswell Wind II QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Boswell Wind III QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Boswell Wind IV QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Chevron Wind QF	-	-	-	-	-	-	-	-	-	-	-	-	-
DCFP QF	179,077	4,050	3,641	2,360	2,435	2,517	6,212	32,407	52,419	40,810	16,860	7,559	7,807
Enterprise Solar I QF	12,352,091	610,749	742,267	965,709	1,095,701	1,238,554	1,358,555	1,512,798	1,490,493	1,160,459	944,327	695,736	536,743
Escalante Solar I QF	11,404,022	560,006	669,967	869,548	997,539	1,175,746	1,287,172	1,398,773	1,375,284	1,074,225	860,392	634,462	500,909
Escalante Solar II QF	10,735,377	526,167	628,933	819,242	937,921	1,111,824	1,216,605	1,322,724	1,291,428	1,012,439	806,961	593,628	467,505
Escalante Solar III QF	10,341,613	512,290	614,790	795,035	912,809	1,083,235	1,187,283	1,286,093	1,255,349	984,296	738,642	544,017	427,775
Evergreen BioPower QF	-	-	-	-	-	-	-	-	-	-	-	-	-
ExxonMobil QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Five Pine Wind QF	9,021,830	550,461	910,272	806,702	853,690	522,219	575,763	675,805	643,960	805,777	800,069	937,020	940,093
Foote Creek III Wind QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Glen Canyon A Solar QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Glen Canyon B Solar QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Granite Mountain East S	10,735,682	542,663	606,878	882,292	972,645	1,141,845	1,237,607	1,309,167	1,249,670	961,810	797,580	573,430	460,094
Granite Mountain West S	7,105,147	359,045	401,777	584,928	644,362	756,525	818,559	867,093	825,673	635,902	527,168	379,923	304,193
Iron Springs Solar QF	11,020,270	627,251	653,455	884,002	997,903	1,114,563	1,262,671	1,319,674	1,305,928	988,606	803,984	570,609	491,624
Kennecott Refinery QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Kennecott Smelter QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Latigo Wind Park QF	9,653,969	1,002,787	916,507	1,120,639	895,224	864,180	755,742	667,602	567,897	623,219	795,200	708,251	736,720
Monticello Wind QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Mountain Wind 1 QF	8,925,025	1,393,376	1,045,925	866,003	681,385	484,114	500,590	411,924	441,353	469,289	677,879	902,060	1,051,128
Mountain Wind 2 QF	13,915,538	2,031,769	1,567,589	1,351,623	1,063,844	758,044	898,954	763,377	735,213	776,297	1,016,122	1,400,570	1,552,135
North Point Wind QF	20,178,389	1,156,036	1,961,106	1,799,285	1,917,085	1,165,782	1,305,519	1,568,381	1,594,337	1,915,585	1,859,066	1,991,105	1,945,101
Oregon Wind Farm QF	12,447,066	716,938	969,731	1,111,800	1,303,200	1,247,048	1,234,482	1,241,162	1,128,038	927,737	733,410	797,174	1,036,346
Pavant II Solar QF	4,765,170	186,479	235,238	366,263	438,365	499,083	545,808	634,302	631,532	450,777	345,921	239,878	191,526
Pioneer Wind Park I QF	11,487,632	1,307,202	927,042	1,298,761	1,017,770	682,100	734,389	850,534	826,139	541,252	870,246	1,349,003	1,083,195
Power County North Win	5,877,495	447,311	592,810	566,287	552,722	383,638	375,783	396,238	395,677	407,429	548,734	563,861	647,004
Power County South Wir	5,236,544	395,001	522,148	510,902	513,013	331,320	334,501	350,551	368,787	360,745	480,238	508,596	560,743
Roseburg Dillard QF	1,278,446	59,044	130,556	65,605	103,400	129,189	78,072	246,922	173,632	74,303	76,449	77,115	64,159
Sage I Solar QF	2,243,423	79,705	78,928	187,861	203,039	233,053	259,536	331,713	331,792	206,029	153,821	103,600	74,348
Sage II Solar QF	2,245,841	79,789	79,021	188,061	203,258	233,267	259,829	332,067	332,160	206,263	153,978	103,728	74,419
Sage III Solar QF	1,848,201	67,187	65,762	155,157	165,491	191,023	212,279	270,704	270,549	170,042	129,039	87,807	63,160
Spanish Fork Wind 2 QF	2,832,096	225,746	182,541	209,510	164,768	158,208	220,711	296,651	324,158	279,769	247,575	257,202	265,257
Sunnyside QF	21,639,974	2,446,459	2,320,817	2,660,539	2,324,750	2,846,154	2,889,978	3,068,755	3,082,522	-	-	-	-
Sweetwater Solar QF	7,672,369	255,091	368,749	557,947	676,497	804,030	969,793	1,098,050	1,027,809	802,870	618,001	295,309	198,224
Tesoro QF	381,028	65,838	48,815	39,139	22,408	34,632	6,534	16,632	29,042	14,608	12,245	16,213	74,921
Threemile Canyon Wind	-	-	-	-	-	-	-	-	-	-	-	-	-
Three Peaks Solar QF	8,357,581	410,917	470,189	619,669	821,295	852,465	901,100	1,026,396	996,590	784,948	664,925	440,537	368,551
Utah Pavant Solar QF	7,238,041	269,622	314,200	538,516	631,865	757,014	843,216	959,499	913,508	764,023	588,085	363,749	294,746
Utah Red Hills Solar QF	11,335,615	481,754	612,345	778,205	1,015,644	1,181,457	1,213,699	1,480,794	1,438,074	1,292,130	799,312	583,575	458,627
Qualifying Facilities Total	326,978,180	22,754,501	24,224,881	28,607,980	30,406,400	30,772,333	32,604,332	34,493,277	33,517,681	26,089,141	23,367,438	20,831,703	19,308,512
Mid-Columbia Contracts													
Douglas - Wells	-	-	-	-	-	-	-	-	-	-	-	-	-
Grant Reasonable	-	-	-	-	-	-	-	-	-	-	-	-	-
Grant Meaningful Priority	-	-	-	-	-	-	-	-	-	-	-	-	-
Grant Surplus	2,265,569	188,797	188,797	188,797	188,797	188,797	188,797	188,797	188,797	188,797	188,797	188,797	188,797
Grant - Priest Rapids	-												

PAC/102
Wilding/3

Mid-Columbia Contracts Total	2,265,569	188,797	188,797	188,797	188,797	188,797	188,797	188,797	188,797	188,797	188,797	188,797	188,797
Total Long Term Firm Purchases	553,122,501	42,827,450	41,613,444	49,330,778	49,678,699	49,921,545	51,433,756	52,234,391	50,744,798	43,317,346	42,745,307	40,014,890	39,260,099
Storage & Exchange													
APS Exchange	-	-	-	-	-	-	-	-	-	-	-	-	-
Black Hills CTs	-	-	-	-	-	-	-	-	-	-	-	-	-
BPA Exchange	-	-	-	-	-	-	-	-	-	-	-	-	-
BPA FC II Wind	-	-	-	-	-	-	-	-	-	-	-	-	-
BPA FC IV Wind	-	-	-	-	-	-	-	-	-	-	-	-	-
BPA So. Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-
Cowlitz Swift	-	-	-	-	-	-	-	-	-	-	-	-	-
EWEB FC I	-	-	-	-	-	-	-	-	-	-	-	-	-
PSCo Exchange	-	-	-	-	-	-	-	-	-	-	-	-	-
PSCO FC III	-	-	-	-	-	-	-	-	-	-	-	-	-
Redding Exchange	-	-	-	-	-	-	-	-	-	-	-	-	-
SCL State Line	-	-	-	-	-	-	-	-	-	-	-	-	-
Tri-State Exchange	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Storage & Exchange	-	-	-	-	-	-	-	-	-	-	-	-	-
Short Term Firm Purchases													
COB	-	-	-	-	-	-	-	-	-	-	-	-	-
Colorado	-	-	-	-	-	-	-	-	-	-	-	-	-
Four Corners	-	-	-	-	-	-	-	-	-	-	-	-	-
Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-
Mead	-	-	-	-	-	-	-	-	-	-	-	-	-
Mid Columbia	8,601,600	560,000	537,600	604,800	-	-	-	2,240,000	2,419,200	2,240,000	-	-	-
Mona	-	-	-	-	-	-	-	-	-	-	-	-	-
NOB	-	-	-	-	-	-	-	-	-	-	-	-	-
Palo Verde	-	-	-	-	-	-	-	-	-	-	-	-	-
SP15	-	-	-	-	-	-	-	-	-	-	-	-	-
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	-	-	-	-	-	-	-	-	-	-	-	-
West Main	-	-	-	-	-	-	-	-	-	-	-	-	-
Wyoming	-	-	-	-	-	-	-	-	-	-	-	-	-
STF Electric Swaps	-	-	-	-	-	-	-	-	-	-	-	-	-
STF Index Trades	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Short Term Firm Purchases	8,601,600	560,000	537,600	604,800	-	-	-	2,240,000	2,419,200	2,240,000	-	-	-

System Balancing Purchases													
COB	34,142,451	71,554	245,539	362,549	(23,370)	(194,216)	(258,331)	16,571,734	10,570,665	3,573,624	254,515	215,947	2,752,242
Four Corners	19,856,962	1,302,612	1,791,521	1,585,243	900,683	843,369	430,448	2,024,961	2,414,407	3,625,500	1,715,088	1,993,183	1,229,948
Mead	14,806,791	970,584	865,686	533,061	648,686	532,954	382,894	2,818,772	2,838,865	2,930,032	1,007,579	677,272	600,406
Mid Columbia	300,835,218	3,813,348	1,374,274	589,586	493,229	1,825,621	8,227,704	62,232,614	81,170,398	51,161,796	24,725,103	22,962,026	42,259,519
Mona	10,502,577	1,700,968	979,440	772,214	650,532	425,229	230,862	433,480	633,018	1,595,725	1,405,469	1,045,224	630,416
NOB	50,022,104	2,379	1,145,680	564,425	220,686	-	70,883	11,719,958	13,065,780	10,866,801	2,485,289	1,545,142	8,335,081
Palo Verde	3,370,938	-	-	387,901	-	-	-	-	-	-	-	1,330,132	1,652,906
EIM Imports/Exports	(92,071,930)	(7,468,400)	(6,275,503)	(6,608,392)	(4,863,579)	(5,008,631)	(5,519,657)	(13,404,003)	(14,367,689)	(11,316,133)	(5,696,084)	(5,444,388)	(6,099,471)
Emergency Purchases	47,135,243	80	696	-	-	-	-	17,976,674	14,550,541	5,544,822	2,383,065	622,061	6,057,304
Total System Balancing Purchases	388,600,354	393,124	127,334	(1,813,414)	(1,973,133)	(1,575,674)	3,564,802	100,374,189	110,875,986	67,982,167	28,280,025	24,946,597	57,418,350
Total Purchased Power & Net Interchang	950,324,455	43,780,574	42,278,378	48,122,164	47,705,566	48,345,871	54,998,558	154,848,579	164,039,985	113,539,513	71,025,331	64,961,487	96,678,449
Wheeling & U. of F. Expense													
Firm Wheeling	158,532,006	13,335,624	13,060,146	13,020,267	13,409,336	12,630,114	14,484,457	13,451,337	13,535,513	12,557,992	12,961,020	12,713,063	13,373,137
C&T EIM Admin fee	2,284,802	184,546	167,911	199,738	189,282	216,532	228,355	197,624	189,924	182,991	165,631	184,972	177,294
ST Firm & Non-Firm	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Wheeling & U. of F. Expense	160,816,808	13,520,170	13,228,057	13,220,005	13,598,619	12,846,646	14,712,812	13,648,961	13,725,436	12,740,983	13,126,652	12,898,036	13,550,431
Coal Fuel Burn Expense													
Carbon	-	-	-	-	-	-	-	-	-	-	-	-	-
Cholla	-	-	-	-	-	-	-	-	-	-	-	-	-
Colstrip	18,388,036	2,072,043	1,841,989	1,854,419	1,282,882	1,964,853	1,671,112	1,465,527	1,664,278	1,443,736	543,783	1,302,245	1,281,169
Craig	14,393,703	1,152,691	994,195	1,121,390	956,833	1,035,837	1,177,623	1,142,183	1,436,133	1,359,374	1,428,306	1,215,461	1,373,676
Dave Johnston	63,751,340	6,936,185	6,215,251	6,182,611	5,877,567	6,850,344	6,598,362	4,066,917	4,748,428	4,022,887	5,020,877	3,426,897	3,805,015
Hayden	10,169,525	978,837	820,387	880,038	791,011	933,233	972,181	892,782	718,385	809,127	647,605	971,304	754,636
Hunter	126,226,934	13,180,130	12,552,683	7,264,069	9,812,297	11,757,419	11,711,725	9,728,305	10,553,489	9,369,145	10,450,356	10,796,272	9,051,044
Huntington	110,658,947	12,088,538	10,335,478	11,661,337	9,038,691	9,333,434	10,292,276	9,049,238	9,926,285	6,277,495	5,555,502	8,286,204	8,814,469
Jim Bridger	196,125,182	17,843,467	14,738,941	15,504,414	7,041,371	4,849,610	6,000,403	22,975,607	23,392,196	21,144,329	20,346,518	20,597,883	21,690,442
Naughton	27,974,534	2,455,600	2,534,981	2,079,348	1,639,001	1,285,309	1,794,323	3,078,659	3,159,683	2,695,679	2,904,664	2,140,640	2,206,645
Wyodak	**32,280,937**	3,194,043	3,293,965	3,378,831	3,201,192	3,225,155	2,977,525	2,726,460	2,585,444	2,248,299	2,563,933	1,755,811	1,130,280
Total Coal Fuel Burn Expense	599,969,137	59,901,534	53,327,868	49,926,456	39,640,846	41,235,196	43,195,530	55,125,678	58,184,322	49,370,071	49,461,544	50,492,717	50,107,376
Gas Fuel Burn Expense													
Chehalis	60,877,049	7,890,844	6,455,337	5,797,497	4,782,048	5,653,574	4,605,260	3,801,632	3,385,761	3,721,291	5,256,998	5,175,646	4,351,162
Currant Creek	55,731,824	7,020,383	2,262,198	4,085,588	4,992,017	3,880,248	5,154,745	7,168,428	5,564,763	4,691,190	2,878,209	4,321,539	3,712,517
Gadsby	13,117,319	1,133,979	780,571	643,240	427,852	484,734	547,369	1,403,750	1,706,097	1,573,408	1,043,090	1,381,925	1,991,304
Gadsby CT	9,466,735	952,440	745,351	569,272	343,417	220,598	244,706	978,781	1,117,130	985,836	864,547	1,136,885	1,307,772
Hermiston	28,824,508	4,317,488	3,251,022	2,855,795	3,018,420	2,828,301	1,487,534	1,868,294	1,787,560	1,901,671	857,493	1,909,797	2,741,132
Lake Side 1	68,555,547	6,861,850	5,347,979	5,306,542	5,639,335	5,401,823	5,476,326	6,276,574	6,419,215	5,770,809	3,903,115	6,279,862	5,872,117
Lake Side 2	50,258,935	4,449,839	2,575,902	2,730,308	1,624,287	43,725	2,733,948	6,229,999	6,266,133	5,631,397	5,453,914	5,729,741	6,789,742
Little Mountain	-	-	-	-	-	-	-	-	-	-	-	-	-
Naughton - Gas	20,696,079	1,874,178	1,237,096	1,417,086	408,029	722,658	1,110,138	2,347,467	2,302,602	1,335,614	1,905,216	1,849,849	4,186,146
Not Used	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Gas Fuel Burn	307,527,995	34,500,999	22,655,456	23,405,327	21,235,404	19,235,661	21,360,026	30,074,925	28,549,261	25,611,216	22,162,582	27,785,245	30,951,893
Gas Physical	(6,259,946)	(887,004)	(767,355)	(738,348)	(524,373)	(518,352)	(507,119)	(575,761)	(581,362)	(567,148)	(593,124)	-	-
Gas Swaps	(17,010,410)	(3,880,502)	(3,040,800)	(1,735,070)	606,000	736,250	642,750	(729,198)	(813,285)	(1,698,525)	(382,618)	(2,721,450)	(3,993,962)
Clay Basin Gas Storage	(452,163)	(251,165)	(212,897)	(82,892)	52,242	52,242	52,242	52,242	52,242	52,242	52,242	(98,940)	(171,968)
Pipeline Reservation Fee	40,138,923	3,405,523	3,220,404	3,328,453	3,277,661	3,310,301	3,282,142	3,398,754	3,396,195	3,357,300	3,401,511	3,362,762	3,397,917

Total Gas Fuel Burn Expense	323,944,398	32,887,851	21,854,809	24,177,470	24,646,934	22,816,102	24,830,041	32,220,963	30,603,051	26,755,086	24,640,595	28,327,617	30,183,880
Other Generation													
Blundell	4,484,106	461,755	417,069	461,755	362,477	432,185	418,243	381,550	390,298	406,476	346,843	229,062	176,392
Blundell Bottoming Cycle	-	-	-	-	-	-	-	-	-	-	-	-	-
Cedar Springs Wind II	-	-	-	-	-	-	-	-	-	-	-	-	-
Dunlap I Wind	-	-	-	-	-	-	-	-	-	-	-	-	-
Ekola Flats Wind	-	-	-	-	-	-	-	-	-	-	-	-	-
Foote Creek I Wind	-	-	-	-	-	-	-	-	-	-	-	-	-
Glenrock Wind	-	-	-	-	-	-	-	-	-	-	-	-	-
Glenrock III Wind	-	-	-	-	-	-	-	-	-	-	-	-	-
Goodnoe Wind	-	-	-	-	-	-	-	-	-	-	-	-	-
High Plains Wind	-	-	-	-	-	-	-	-	-	-	-	-	-
Leaning Juniper 1	-	-	-	-	-	-	-	-	-	-	-	-	-
Marengo I Wind	-	-	-	-	-	-	-	-	-	-	-	-	-
Marengo II Wind	-	-	-	-	-	-	-	-	-	-	-	-	-
McFadden Ridge Wind	-	-	-	-	-	-	-	-	-	-	-	-	-
Pryor Mountain Wind	-	-	-	-	-	-	-	-	-	-	-	-	-
Rolling Hills Wind	-	-	-	-	-	-	-	-	-	-	-	-	-
Seven Mile Wind	-	-	-	-	-	-	-	-	-	-	-	-	-
Seven Mile II Wind	-	-	-	-	-	-	-	-	-	-	-	-	-
Black Cap Solar	-	-	-	-	-	-	-	-	-	-	-	-	-
TB Flats Wind	-	-	-	-	-	-	-	-	-	-	-	-	-
TB Flats Wind II	-	-	-	-	-	-	-	-	-	-	-	-	-
Integration Charge	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Other Generation	4,484,106	461,755	417,069	461,755	362,477	432,185	418,243	381,550	390,298	406,476	346,843	229,062	176,392
Net Power Cost	**1,683,929,925**	**114,090,709**	**108,129,869**	**116,611,131**	**111,133,706**	**110,842,752**	**118,521,762**	**211,812,933**	**223,833,034**	**159,989,429**	**121,478,587**	**126,977,959**	**160,508,054**

REDACTED
Docket No. UE 400
Exhibit PAC/103
Witness: Michael G. Wilding

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED

Exhibit Accompanying Direct Testimony of Michael G. Wilding

Aurora Test NPC Report

March 2022

THIS EXHIBIT IS CONFIDENTIAL IN ITS ENTIRETY AND IS PROVIDED UNDER SEPARATE COVER

REDACTED
Docket No. UE 400
Exhibit PAC/104
Witness: Michael G. Wilding

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED

Exhibit Accompanying Direct Testimony of Michael G. Wilding

GRID Test NPC Report

March 2022

THIS EXHIBIT IS CONFIDENTIAL IN ITS ENTIRETY AND IS PROVIDED UNDER SEPARATE COVER

REDACTED
Docket No. UE 400
Exhibit PAC/105
Witness: Michael G. Wilding

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED

Exhibit Accompanying Direct Testimony of Michael G. Wilding

Aurora Overview Presentation

March 2022

THIS EXHIBIT IS CONFIDENTIAL IN ITS ENTIRETY AND IS PROVIDED UNDER SEPARATE COVER

REDACTED
Docket No. UE 400
Exhibit PAC/106
Witness: Michael G. Wilding

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED

Exhibit Accompanying Direct Testimony of Michael G. Wilding

Update to Renewable Energy Production Tax Credits

March 2022

THIS EXHIBIT IS CONFIDENTIAL IN ITS ENTIRETY AND IS PROVIDED UNDER SEPARATE COVER

Docket No. UE 400
Exhibit PAC/107
Witness: Michael G. Wilding

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Michael G. Wilding

Step Log Change

March 2022

2023 TAM Step Log

ORTAM22			$ 1,369,404,716
	Description	**Detail**	**Impact**
	Routine Updates		$ 155,400,245.53
Step 1	Regulating Reserve Requirement	Regulating reserve requirements are changed to accurately reflect reliability and resource adequacy operational standards	$ 67,464,621.92
Step 2	Planned Outages	Changed outage pattern from Normalized to Budgeted	$ 13,893,198.25
Step 3	DA-RT Price Adder	Changed Price Adder from a flat value to a % of market price	$ 20,009,225.76
Step 4	Market Capacity Update	Use four-year average as opposed to average of two highest years.	$ 22,651,343.05
Step 5	Thermal Attributes Update	Updated the attributes of certain thermal units to reflect seasonal operating capacities	$ 23,829,805.94
Step 6	Startup Costs	Startup costs for Gas units that use gas as a startup fuel	$ 6,154,049.75
Step 7	Trapped Energy	Lowered the revenue from trapped energy from 75% of market to 25% of market	$ 181,945.49
Step 8	Coal Plant Economic Cycling	Coal units are allowed to cycle economically	$ 4,940,773.12
ORTAM23			$ 1,683,929,925

Docket No. UE 400
Exhibit PAC/108
Witness: Michael G. Wilding

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Michael G. Wilding

January 28, 2022 Notice Letter

March 2022

PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
Portland, Oregon 97232

January 28, 2022

VIA ELECTRONIC MAIL

RE: Docket UE 390
2023 Transition Adjustment Mechanism – PacifiCorp's Notice of Methodology Changes

Under the Transition Adjustment Mechanism (TAM) Guidelines, PacifiCorp d/b/a Pacific Power provides this Notice of Methodology Changes for the 2023 TAM. This notice complies with an amendment to the TAM Guidelines adopted by the Public Utility Commission of Oregon (Commission) in Order No. 09-432. This amendment provides that "[t]he Company will provide notice of substantial changes to the methodologies used to calculate the cost elements and other inputs to the Aurora model or to the logic of the Aurora model by March 1st of the year of a stand-alone TAM filing."[1] Consistent with Order No. 21-379, PacifiCorp will be filing the TAM on March 1, 2022. As a result, the company is providing this notice to comply with the pre-filing review requirement and the methodology change notice requirement on January 28, 2022.

PacifiCorp provides notice of the following planned changes to the 2023 TAM:

- The Aurora optimization model will replace the GRID[2] model for evaluating Net Power Costs
- Wholesale sales market caps will be based on the four-year historical average of short-term firm, balancing and spot, differentiated by on- and off-peak hours. This was completed consistent with the Commission's continued review of this issued as identified in Order No. 21-379.[3]
- The day-ahead real-time price adder will be changed to a percentage of market prices
- The regulating reserve requirement will be updated to reflect higher reliability and resource adequacy standards consistent with the company's 2021 integrated resource plan.
- The trapped energy revenue will be updated to more accurately reflect its value.
- The planned maintenance outages will be based on the Company's budgeted outage plan.

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[1] *In the Matter of PacifiCorp d/b/a Pacific Power 2010 Transition Adjustment Mechanism*, Docket UE-207, Order No. 09-432, Appendix A at 4-5 (Oct. 30, 2009).
[2] Generation and Regulation Initiative Decision Tools model.
[3] *In the Matter of PacifiCorp d/b/a Pacific Power 2022 Transition Adjustment Mechanism*, Docket UE 390, Order No. 21-379 at 28 (Nov. 1, 2021).

Please direct any questions regarding this notice to Cathie Allen, regulatory affairs manager at 503-813-5934.

Sincerely,

Shelley McCoy

Shelley McCoy
Director, Regulation

cc: UE 390 Service List

REDACTED
Docket No. UE 400
Exhibit PAC/200
Witness: James Owen

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED

Direct Testimony of James Owen

March 2022

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Highly Confidential Exhibit PAC/201—Naughton Coal Supply Agreement Analysis

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I. INTRODUCTION AND QUALIFICATIONS

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

A. My name is James Owen. My business address is 1407 West North Temple, Suite 210, Salt Lake City, Utah 84116. My title is Vice President of Environmental, Fuels, and Mining.

Q. Briefly describe your education and professional experience.

A. I have a Bachelor of Science Degree in Mining Engineering, a Master of Business Administration Degree, and a Juris Doctorate of Law Degree, all from the University of Utah. I joined the Utah Department of Natural Resources – Division of Oil Gas and Mining in November 2008, and held positions of increasing responsibility within the agency, including responsibilities for environmental permitting, enforcement of environmental compliance, engineering design, oversight of mine reclamation bonding, environmental program management, and legislative and policy management. I joined PacifiCorp as Director of Environmental in February 2018. I have assumed positions of increasing responsibility since that time and currently serve as Vice President of Environmental, Fuels, and Mining. My current responsibilities encompass strategic planning, stakeholder engagement, regulatory support, support of major generation resource additions, direct oversight of fueling strategy, management of mining operations, and direct oversight of major environmental compliance projects.

Q. Have you testified in previous regulatory proceedings?

A. Yes. I have provided testimony on behalf of the Company in proceedings before the

Public Utility Commission of Oregon (Commission) and the public utility commissions in Utah, Idaho, and Wyoming.

II. PURPOSE AND SUMMARY

Q. What is the purpose of your testimony?

A. I explain PacifiCorp's overall approach to providing the coal supply for its coal-fired generating plants, and I support the level of coal costs included in fuel expense in PacifiCorp's 2023 Transition Adjustment Mechanism (TAM). To demonstrate the reasonableness of these costs, my testimony:

- Provides a brief update of recent changes in the coal market and how those changes impacted the 2023 TAM fuel costs.
- Details any new coal supply agreements (CSA) that PacifiCorp entered into since the 2022 TAM, and provides highly confidential exhibits detailing the new CSAs and the analysis that was undertaken in accordance with the Commission's Order No. 20-392 in the 2021 TAM;
- Provides an update on the Company's evaluation of the termination provisions for the Huntington CSA, provides updates regarding long-term fuel plan analysis for the Jim Bridger plant, and explains the primary reasons behind the reduction to the total-company coal costs—close to $50 million—reflected in the 2023 TAM;[1] and
- Provides updated coal pricing and background on third-party coal contracts and affiliate-owned mines.

[1] Unless otherwise stated, all figures in my testimony are stated on a total-company basis.

III. CHANGES IN COAL MARKET CONDITIONS

Q. What significant changes have occurred in the coal market in the past year?

A. Beginning in September 2021, high domestic natural gas prices, low inventories at coal plants, increased demand abroad for coal exports, and general market inflation resulted in rapidly escalating coal prices. By November of 2021, market coal prices throughout the United States had increased significantly. For example, spot prices for 8,800 British thermal units per pound (Btu/lb) of coal produced in the Powder River Basin more than doubled between September and November of 2021. Although coal prices appear to be slowly declining from the recent spikes in price, the current coal price forecast for 2023 remains significantly higher than was expected in the 2022 TAM. The following detail shows that 2023 coal pricing is forecast to be on average 22 percent higher than was expected in the 2022 TAM in the primary coal basins that supply PacifiCorp's plants.

	2023 Estimated Pricing			
Coal Basin	2023 Forecast Price/Ton (2022 TAM)	2023 Forecast Price/Ton (2023 TAM)	Increase Price/Ton	% Increase
Powder River Basin 8,400	[redacted]			
Powder River Basin 8,800				
Utah				
Colorado/Yampa				
Average Price Increase				22%

Source: Energy Ventures Analysis: 2022 TAM assumptions published February 2021 and 2023 TAM assumptions published Q4 2021.

Q. How has this increase in market coal prices impacted the 2023 TAM's estimated fuel costs?

A. The Company's prudent coal contracting practices have largely shielded the

Company and its customers from these coal price increases. The Company purchases coal from captive mines and third-party suppliers, typically under short- to medium-term contracts. Currently, due to the increased coal demand, coal suppliers have increased coal sales opportunities. Most of the Company's coal contracts include fixed pricing provisions that do not escalate with general inflation. As a result, the impact of the increased coal pricing is largely contained to PacifiCorp plants with CSAs that terminated in 2021 or that are terminating in 2022. Specifically, this applies to the Kemmerer mine which supplies the Naughton plant, the Black Butte mine which serves the Jim Bridger plant, the Wyodak mine which serves the Wyodak plant, and coal purchases from the Power River Basin, which are required to supply a portion of Dave Johnston plant's requirements. These impacts are discussed in more detail later in my testimony.

IV. NAUGHTON COAL SUPPLY AGREEMENT

Q. Has PacifiCorp entered into any new CSAs since it filed reply testimony in the 2022 TAM?

A. Yes. PacifiCorp has entered into a new CSA for the Naughton plant (Naughton CSA). Consistent with the requirements of the order from the 2022 TAM,[2] my testimony and the corresponding exhibit provide additional information demonstrating the prudence of the Naughton CSA.

Q. Can you provide some background on the Naughton plant and the Naughton CSA?

A. The Naughton Plant (Naughton) is located in Kemmerer, Wyoming and is wholly

[2] *In the Matter of PacifiCorp, d/b/a Pacific Power, 2022 Transition Adjustment Mechanism*, Docket No. UE 390, Order No. 21-379 at 6-7 (Nov. 1, 2021).

owned by PacifiCorp. PacifiCorp's prior agreement for Naughton's coal supply terminated December 31, 2021. Naughton Units 1 and 2, rated at 156 and 201 megawatts (MW), respectively, operate on coal and Naughton Unit 3 operates on natural gas. PacifiCorp's latest 2021 Integrated Resource Plan (IRP) identified December 31, 2025, as the end of useful life for Units 1 and 2. Naughton Units 1 and 2 are also subject to environmental compliance obligations under the federal coal combustion residuals rule, which, if finalized, will not allow Units 1 and 2 to operate on coal beyond their current remaining useful life. PacifiCorp has executed the Naughton CSA with the Kemmerer Mine, operated by Kemmerer Operations, LLC, for the purchase of Naughton's coal supply through [redacted].

Q. What is the term of the Naughton CSA?

A. The term of the Naughton CSA is [redacted]. This term is consistent with PacifiCorp's recent practice of limiting its CSAs to five years or less to maintain flexibility in fuel supply and generation planning.

Q. What are the terms for annual volume and pricing in the Naughton CSA?

A. Annual volume and pricing is as follows:

Year	Minimum Tons	Maximum Tons	Price/Ton
[redacted]			

Q. Does the Naughton CSA include a minimum take requirement?

A. Yes. Like the previous CSA, the Naughton CSA is a minimum take requirements agreement. PacifiCorp would not have been able to secure the necessary coal supply at a favorable contract price without agreeing to a minimum take obligation during those years. PacifiCorp was able to establish significantly lower contract minimums for the Naughton CSA, as illustrated above.

Q. Why are "minimum take" provisions generally required in CSAs?

A. Without some form of commitment by customers to purchase a minimum amount of coal, a coal supplier, especially those which are captive in whole or in part to coal-fired power plants, cannot develop adequate mine permits and plans, project for capital and operating costs, or have an assured revenue stream for the coal they produce. In short, coal mines cannot operate without the ability to sell coal. Without a minimum take provision, the CSA would merely be an option for the customer to purchase coal if desired while paying no cost for this option. Coal and coal mining assets remain marketable commodities. No coal producer could be reasonably expected to agree to an option-only contract as it would require a large investment of capital for coal reserves, mine development, and mining equipment, along with ongoing operating costs, with no assurance that any coal would be purchased to offset those costs. Further, coal suppliers (and similarly coal transporters) require a commitment to purchase at a regular rate ("ratable take") to employ and maintain a workforce able to meet the customer's requirements. Coal mining operations cannot simply be 'turned on or off' quickly when it is convenient for the customer. As a result, while some CSAs may provide flexibility for the customer to vary its purchase volumes, nearly all CSAs have a minimum volume commitment for customers to purchase coal.

Q. In the order from the 2022 TAM, the Commission identified several elements that should be addressed when presenting a new CSA. What are those elements?

A. The 2022 order stated the following items should be addressed when PacifiCorp presents a new CSA:

- PacifiCorp will need to explain in detail how economic cycling was considered when deciding on minimum take levels in the contract, a comparison of the MMBtu level from generation analysis to the contracted-for level, and to provide the workpapers used in analysis of the generation forecasts for CSA negotiations.[3]
- PacifiCorp will need to explain how it incorporates its IRP planning into its TAM-reviewed fuel contracts, or its management of those contracts.[4]
- PacifiCorp will need to show it considered future costs in multiyear contracts, especially given that its plans for operating a plant generally would be expected to show declining production before retirement.[5]
- PacifiCorp will need to explain how it is allowing for an orderly sequence towards retirement and ensuring flexibility for reduced capacity factors and consumption of the coal pile, and how it will manage the contract in the event that circumstances change from those expected when it was signed.[6]

[3] Order No. 21-379 at 5.
[4] *Id.* at 7.
[5] *Id.*
[6] *Id.*

Q. Has PacifiCorp conducted an analysis for the Naughton CSA that involves these elements?

A. Yes; please refer to Highly Confidential Exhibit PAC/201 which contains an overview and background of the Naughton CSA and the economic analysis supporting the Naughton CSA respectively. These documents describe in detail the Naughton CSA and the economic analysis that PacifiCorp conducted which showed the prudence of PacifiCorp's execution of the Naughton CSA. Highly Confidential Exhibit PAC/201 demonstrates how PacifiCorp incorporated IRP-type planning and modeling into the decision process relating to the Naughton CSA.

V. HUNTINGTON COAL SUPPLY AGREEMENT

Q. In the Commission's 2022 TAM Order, the Commission raised a concern about the minimum take levels in the current CSA for Huntington (Huntington CSA).[7] Please provide a brief history of the Huntington CSA.

A. As part of the closure of PacifiCorp's Deer Creek Mine in 2014, the Company executed a long-term CSA with Wolverine Fuels, LLC (Wolverine) formerly known Bowie Resource Partners, LLC (Bowie), whereby they agreed to supply the Company's coal requirements for the Huntington Plant (Huntington) from the time the Deer Creek Mine closed through December 31, 2029.

[7] Order No. 21-379 at 23.

Q. The Commission has requested that PacifiCorp present an analysis and thoroughly explore the costs and benefits of contract termination or renegotiation of the Huntington CSA.[8] When will PacifiCorp be providing this analysis?

A. PacifiCorp is working with Energy Ventures Analysis to produce a thorough analysis on this topic and anticipates providing this analysis to parties by April 15.

VI. JIM BRIDGER MATERIAL AND SUPPLY COSTS

Q. In the 2022 TAM Order, the Commission requested that PacifiCorp include "a discussion of [Material & Supply] costs in its updated Jim Bridger long-term fuel plan so that parties have the opportunity to review components as well as the whole of BCC costs."[9] How is PacifiCorp addressing this issue?

A. While the Commission order required PacifiCorp to include a discussion of coal and reclamation costs in the updated Jim Bridger long-term fuel plan, PacifiCorp filed a motion to delay the filing of the long-term fuel plan because of the uncertainty surrounding Jim Bridger plant operating levels. Therefore, PacifiCorp is providing the requested information based on production and cost information assumed in the 2023 TAM. Please refer to Confidential Exhibit PAC/202. The referenced exhibit contains the following information:

- Tons Delivered
- Cubic Yards moved (production and final reclamation)
- Coal Costs (by component)
- Final Reclamation Costs (by component)

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[8] *Id.*
[9] *Id.* at 15.

- Total Costs (by component)
- Operating Costs (by component)

The "Adjusted Dollars" total in the "Coal Cost" column is the amount included in the 2023 TAM and represents estimated costs incurred to produce and deliver coal to the Jim Bridger plant from Bridger Coal Company (BCC). Final reclamation costs represent costs to complete planned final reclamation activities. The column labeled "Total Costs" is the sum of projected costs incurred to complete coal production and final reclamation activities. The column labeled "Operating Cost" combines coal and reclamation costs by component and aligns with BCC's reporting structure.

Q. Does this exhibit show that the material and supply costs included in the TAM are appropriate?

A. Yes. Confidential Exhibit PAC/202 identifies costs incurred to produce and deliver coal, as well as costs to complete final reclamation activities. This is consistent with previous testimony[10] filed in the 2022 TAM and demonstrates that when evaluating the prudence of operating costs incurred at BCC, both coal production and final reclamation activities should be considered.

VII. OVERVIEW OF PACIFICORP'S COAL SUPPLIES

Q. How does PacifiCorp plan to meet fuel supply requirements for its coal plants in 2023?

A. PacifiCorp employs a diversified coal supply strategy, as reflected below in Confidential Table 1. PacifiCorp will supply 86.1 percent of its 2023 coal requirements with third-party coal supplies and 13.9 percent with coal from its

[10] *In the Matter of PacifiCorp, d/b/a Pacific Power, 2022 Transition Adjustment Mechanism*, Docket No. UE 390, Exhibit PAC/600, Ralston/30:15-20 (Jul. 9, 2021).

captive affiliate mines. Within the third party contracts: (1) 58.6 percent of the total coal requirement will be supplied from fixed-price contracts; (2) 3.1 percent will be supplied under variable-priced contracts that increase or decrease based on changes to producer and consumer price indices; and (3) 24.4 percent of the total coal requirement will be supplied from contracts for the Jim Bridger, Wyodak, and Dave Johnston plants to be negotiated in 2022 and will be discussed later in my testimony.

2023		**Price**	**New**	**MMBtus**		
Company/Mine	**Plant**	**Reopener**	**Contract**	**(000s)**	**(000s)**	**Percent**
Affiliate Mines				[redacted]	[redacted]	
Bridger Coal/Bridger	Jim Bridger			[redacted]	[redacted]	
Trapper Mining/Trapper	Craig			[redacted]	[redacted]	
Subtotal Affiliate Mines				[redacted]	[redacted]	13.9%
Fixed Price Contracts				[redacted]	[redacted]	
Wolverine/Sufco, Skyline	Huntington			[redacted]	[redacted]	
Wolverine/Sufco, Skyline	Hunter			[redacted]	[redacted]	
Bronco/Emery	Hunter			[redacted]	[redacted]	
Peabody/Twentymile	Hayden	√		[redacted]	[redacted]	
Peabody/NARM	Dave Johnston			[redacted]	[redacted]	
Peabody/Caballo	Dave Johnston			[redacted]	[redacted]	
Kemmerer Operations	Naughton		√	[redacted]	[redacted]	
Subtotal Fixed Price Contracts				[redacted]	[redacted]	58.6%
Variable Price Contracts				[redacted]	[redacted]	
Westmoreland/Rosebud	Colstrip			[redacted]	[redacted]	
Subtotal Variable Price Contracts				[redacted]	[redacted]	3.1%
Future Contracts				[redacted]	[redacted]	
Lighthouse Resources/Black Butte	Jim Bridger			[redacted]	[redacted]	
Black Hills/Wyodak	Wyodak			[redacted]	[redacted]	
Unspecified PRB Mines	Dave Johnston			[redacted]	[redacted]	
Total Other				[redacted]	[redacted]	24.4%
Total Coal Supplies				[redacted]	[redacted]	100%

Note: Delivered MMBtus are calculated from consumption estimates provided by the generation requirements in Aurora to accommodate targeted inventory stockpiles

Q. Has total coal-fuel expense in the 2023 TAM decreased from the level reflected in PacifiCorp's 2022 TAM?

A. Yes. As stated in the testimony of Mr. Michael G. Wilding, total coal-fuel expense has decreased by [redacted] in the 2023 TAM. This decrease is the result of an [redacted] volume reduction in coal-fired generation, partially offset by approximately [redacted] in higher coal prices. These variances are shown in Confidential Table 2 below.

Confidential Table 2: Coal Fuel Variance - 2023 TAM vs. 2022 TAM

Plant	Contract	Millions ($)
Price Variance		
Affiliate Mines		[redacted]
Jim Bridger	Bridger Coal Company	
Craig	Trapper Mining	
Subtotal Affiliate Mines		
Third-Party Contracts		
Naughton	Kemmerer Operations	
Wyodak	Wyodak Resources	
Dave Johnston	Powder River Basin	
Dave Johnston	BNSF	
Jim Bridger	Black Butte Coal	
Jim Bridger	UPRR	
Hunter	Wolverine Fuels	
Hunter	Bronco	
Huntington	Wolverine Fuels	
Colstrip	Westmoreland	
Hayden	Peabody	
Subtotal Third-party Contracts		
Total Price Variance		$ 34.7
Volume Variance		[redacted]
Jim Bridger		
Huntington		
Naughton		
Craig		
Wyodak		
Other Plants		
Total Volume Variance		$ (82.5)
Total Coal Fuel Variance - Increase/(Decrease)		$ (47.8)

VIII. JIM BRIDGER FUEL SUPPLY

A. Bridger Coal Company (BCC)

Q. Please briefly summarize the benefits for PacifiCorp customers which are associated with PacifiCorp's partial ownership of BCC.

A. Ownership in BCC allows PacifiCorp to flex coal deliveries up or down, within certain constraints, to better align Jim Bridger plant delivered and consumed coal quantities. Mine ownership also reduces coal supply delivery risk, mitigates unfavorable impacts of unexpected coal delivery changes, and has historically improved contract price terms with the third-party coal supplier.

Q. Please describe the change in BCC costs in the 2023 TAM.

A. BCC costs in the 2023 TAM are forecast to be [redacted] higher than the 2022 TAM. The cost for the base mine plan increased by [redacted] or [redacted], from [redacted] in the 2022 TAM to [redacted] in the 2023 TAM as shown in Confidential Table 3. The 2023 TAM assumes [redacted] base tons are delivered, which is [redacted] less tons delivered than in the 2022 TAM. In the 2023 TAM, the cost for supplemental coal increases by [redacted], from [redacted] in the 2022 TAM to [redacted] in the 2023 TAM. The change in the supplemental price, combined with delivering [redacted] fewer tons results in an unfavorable supplemental price variance of [redacted].

Confidential Table 3: Jim Bridger Plant Coal Deliveries

	2023 TAM			Update			Variance			Price
	Tons	Dollars	$ / Ton	Tons	Dollars	$ / Ton	Tons	Dollars	$ / Ton	Variance
Bridger Coal Deliveries	[redacted]									
Bridger Base Mine Plan										
Supplemental Coal										
Total Bridger Coal										
Black Butte Deliveries										
Total Jim Bridger Plant										

Q. Please summarize why BCC base mine costs increase by [redacted] in the 2023 TAM.

A. The change is due to delivering [redacted] base tons at an increased cost of [redacted], an increase of [redacted] for materials and supplies, a [redacted] increase for reduced gains on asset sales, a [redacted] increase for a reduced final reclamation credit, and an increase of [redacted] due to a lower heat content of the coal delivered. These increases are partially offset by reductions of [redacted] for labor and benefits, [redacted] for coal inventory, [redacted] for depreciation and [redacted] for other miscellaneous items.

Q. Please explain operating mine plan differences at BCC between the 2023 TAM and the 2022 TAM.

A. In the 2023 TAM, the equipment fleet moves [redacted] cubic yards of material and uncovers [redacted] tons. In the 2022 TAM, the equipment fleet moved [redacted] cubic yards and uncovered [redacted] tons. The increase in cubic yards moved is mainly due to operating more dragline shifts in the 2023 TAM. The mobile equipment fleet was scheduled to operate two shifts per day, four days per week and

10 hours per day in both TAM filings.

Q. Please summarize why BCC supplemental mine costs increased in the 2023 TAM.

A. The supplemental cost in the 2023 TAM is a combination of incremental surface mined coal and underground stockpiled coal available for delivery. The surface mined incremental coal price was derived by evaluating production and cost differentials between two operating plans. Pricing for the underground stockpiled coal was derived by combining the coal inventory value and costs for royalties, production taxes/fees, loading, haulage and conveying costs. The supplemental cost in the 2022 TAM was based on the incremental cost of surface mine coal using the same surface mine price derivation process discussed above.

Q. Please explain why materials and supplies increased by [redacted] in the 2023 TAM.

A. As discussed above, the equipment fleet moves more cubic yards of material, uncovers more coal and consequently operates more hours in the 2023 TAM than assumed in the 2022 TAM. Specifically, costs increased by [redacted] for explosives, [redacted] for diesel fuel/gasoline, [redacted] for electricity, [redacted] for repair parts and [redacted] for other operating supplies. Approximately [redacted] of the diesel fuel/gasoline increase total of [redacted] is due to increased pricing.

Q. Please explain why reduced gains on asset sales impacted BCC coal costs in the 2023 TAM.

A. Fuel costs from BCC to the Jim Bridger plant were reduced in the 2022 TAM by proceeds from the disposal of underground mine assets. In the 2023 TAM, no asset disposals are scheduled to occur.

Q. Why did the credit for final reclamation decrease by [redacted]?

A. The 2022 TAM assumed the mine would complete [redacted] cubic yards of final reclamation at the surface mine and spend [redacted] to reclaim underground mine facilities and structures. The 2023 TAM assumes the mine will complete [redacted] cubic yards of final reclamation and spend [redacted] to reclaim underground mine facilities and structures. Decreased spending in the 2023 TAM for underground mine reclamation and the movement of [redacted] fewer cubic yards of waste material reduces the final reclamation credit by [redacted] in the 2023 TAM.

Q. Please explain how a change in the base heat content increased costs by [redacted].

A. The average Btu/lb content assumed delivered in the 2022 TAM was [redacted]. The average Btu/lb content of coal projected to be delivered in the 2023 TAM is [redacted]. The projected decrease in the heat content of [redacted] Btu/lb results in an unfavorable cost increase of [redacted].

Q. Why did base labor costs decrease by [redacted]?

A. The 2022 TAM included underground mine labor and benefit costs in the first quarter of 2022. The underground mine ceased coal production in the fourth quarter of 2021 and no direct underground mine labor charges will be incurred in the 2023 TAM.

Q. Please explain why base coal inventory costs decreased by [redacted] in the 2023 TAM?

A. The 2022 TAM assumed BCC would deliver [redacted] tons of coal from inventory at a cost of [redacted]. The 2023 TAM forecasts that BCC will deliver [redacted] tons of coal from inventory at a cost of [redacted]. In summary, the 2023 TAM assumes [redacted] less tons will be delivered from inventory which will reduce BCC operating costs by [redacted].

Q. Why did depreciation costs decrease by [redacted] in the 2023 TAM?

A. The 2022 TAM included [redacted] for underground mine depreciation and [redacted] for surface mine depreciation. The 2023 TAM includes [redacted] for underground mine depreciation and [redacted] for surface depreciation. The underground mine closure reduced depreciation costs by [redacted] and less capital spending is forecast at the surface mine, which reduces depreciation by [redacted].

Q. Please identify cost components included in the miscellaneous cost decrease of [redacted].

A. Cost components included in the miscellaneous category with slight cost decreases include deferred longwall amortization, insurance, black lung excise tax, and the management fee.

Q. In Order No. 13-387, the Commission ordered the Company to remove certain operations and maintenance costs embedded in the costs of coal from its affiliate captive mines.[11] In this filing, does PacifiCorp adjust the price of coal from BCC consistent with this order?

A. Yes. In the 2023 TAM the Company reduces BCC costs by approximately [redacted] to reflect removal of management overtime and 50 percent of annual incentive plan awards.

B. Jim Bridger Third-Party Coal Supply

Q. What is the expected change in third-party coal prices for the Jim Bridger plant in the 2023 TAM?

A. Delivered costs for the [redacted] of Black Butte coal increased from [redacted] in the 2022 TAM to [redacted] in the 2023 TAM, or [redacted] overall. The existing agreement allowed for [redacted] originally planned to be purchased in 2021 to be deferred to 2022. The price of the deferred tons is [redacted]. The remaining [redacted] are still to be negotiated as part of a new CSA and included an estimated price of [redacted] in the 2022 TAM. The Black Butte price for 2023 is estimated at [redacted] due to recent increases in market coal prices. This estimate will be updated if a new contract is executed through the upcoming TAM update. The Union Pacific agreement required for delivery of coal from Black Butte is forecasted to increase by [redacted] in delivered costs.

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[11] *In the Matter of PacifiCorp d/b/a Pacific Power 2014 Transition Adjustment Mechanism*, Docket No. UE 264, Order No. 13-387 (Oct. 28, 2013).

IX. THIRD-PARTY COAL CONTRACTS

Q. Please discuss the change in overall third-party coal-supply costs in the 2023 TAM.

A. PacifiCorp expects a price variance net increase of the third-party coal-supply costs of [redacted], as shown in Confidential Table 2 above. The details by plant are described below.

A. Coal Supply Agreements for the Wyoming Plants

1. Naughton

Q. Please describe the coal supply arrangement for the Naughton plant in 2023.

A. As discussed above, the Naughton plant is supplied by the adjacent Kemmerer Mine under the Naughton CSA [redacted].

Q. Please describe the Naughton plant's coal cost change in the 2023 TAM.

A. Total delivered coal cost at Naughton increased from [redacted] in the 2022 TAM to [redacted] in the 2023 TAM, or [redacted] overall. The new contract provides for greater supply flexibility and includes a lower minimum contractual obligation of [redacted] in 2023, a decrease of [redacted], when compared to the prior contract minimum obligation of [redacted] per year. Rising general inflation, the reduced contractual commitment and added coal supply flexibility are the primary drivers increasing the contract price.

2. Wyodak

Q. Please describe the estimated price increase related to the Wyodak plant CSA.

A. Delivered coal costs increased from [redacted] in the 2022 TAM to an estimated [redacted] in the 2023 TAM, or [redacted] overall. The current CSA will end

December 31, 2022. A new CSA will be negotiated during 2022 and will reflect current coal prices. If possible, the new contract price will be included in this year's TAM update.

3. Dave Johnston

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

A. Dave Johnston plant delivered coal costs increased by [redacted], or [redacted], in the 2023 TAM compared to the 2022 TAM. The increase is due to an increase in coal costs of [redacted] and an increase of rail cost of approximately [redacted] due to increases to rail indices and diesel fuel costs.

Q. Please describe the unidentified coal for the Dave Johnston plant included in Confidential Table 1.

A. For 2023 the Company has contracted for approximately [redacted] of Dave Johnston's coal supply and will rely on a request for proposal to fill this open position. The coal price applied to this open position reflects the average 2023 forward price for Powder River Basin 8400 Btu coal of [redacted]. The 2023 price is [redacted] higher than the 2022 Powder River Basin 8400 Btu price of [redacted] that was used for the open position in the 2022 TAM and reflects the impact of increased coal market pricing.

B. Coal Supply Agreements for the Utah Plants

1. Hunter

Q. Please describe the change in coal costs at the Hunter plant in the 2023 TAM.

A. Coal prices have increased [redacted], from [redacted] in the 2022 TAM to [redacted] in the 2023 TAM ([redacted] overall). The coal prices for the agreement with the Bronco Utah Operations, LLC, have increased [redacted], from [redacted] in the 2022 TAM to [redacted] in the 2023 TAM ([redacted] overall). The coal prices for the agreement with Wolverine have increased [redacted], from [redacted] in the 2022 TAM to [redacted] in the 2023 TAM ([redacted] overall). The increased coal prices result from the annual price increases in the respective CSAs and increasing transportation indices.

2. Huntington

Q. Please describe the coal supply arrangement for the Huntington plant in 2023.

A. The coal supply to the Huntington plant is provided under a minimum take requirements contract with Wolverine, which terminates in 2029. This is a "delivered to the plant" agreement that requires Wolverine to pay the transportation costs, although PacifiCorp is responsible for limited trucking cost escalation.

Q. What coal supply costs for the Huntington plant are included in the 2023 TAM?

A. For the Huntington plant, delivered coal prices increased from [redacted] in the 2022 TAM to [redacted] in the 2023 TAM, an overall increase of [redacted] or [redacted] for the weighted average price under the Huntington CSA. The Huntington CSA price is higher in the 2023 TAM primarily because of an increase in the transportation cost escalator, partially offset by an increase in tier 2 coal deliveries under the Huntington CSA.

Q. Does the 2023 TAM reflect Energy West pension costs?

A. No. As stated under Order No. 20-392 in docket UE 375, PacifiCorp agreed to remove these costs from the TAM as they are now included in base rates through the last general rate case, docket UE 374.

C. Coal Supply Agreements for the Jointly-Owned Plants

1. Craig

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

A. In 2023 the Craig plant will be supplied under an agreement with the Trapper mine, which is an affiliate captive mine owned by three of the five Craig plant owners, including PacifiCorp. Trapper mine costs have decreased [redacted], from [redacted] in the 2022 TAM to [redacted] in the 2023 TAM, a [redacted] overall price decrease. The price decrease is primarily due to lower mining costs at the Trapper mine due to a change in mining method. Deliveries from Trapper mine have decreased [redacted] from [redacted] in the 2022 TAM to [redacted] in the 2023 TAM.

2. Hayden

Q. Please describe the change in Hayden plant's coal cost in the 2023 TAM.

A. Delivered coal prices decreased [redacted], from [redacted] in the 2022 TAM to [redacted] in the 2023 TAM, a decrease of [redacted]. [redacted]

REDACTED

3. Colstrip

Q. Please describe the change in coal cost at the Colstrip plant in the 2023 TAM.

A. Delivered coal prices increased [redacted], from [redacted] in the 2022 TAM to [redacted] in the 2023 TAM, an increase of [redacted]. PacifiCorp developed the 2023 TAM costs for the Colstrip plant based on the CSA that was signed December 5, 2019. The increase in costs is primarily due to an increase in the contract indices, partially offset by a higher volume of tier 2 coal being purchased.

X. SUMMARY

Q. Please summarize the benefits of PacifiCorp's coal fuel strategy.

A. Customers have significantly benefited from PacifiCorp's prudent and diversified fueling strategy, which relies upon fixed-price contracts, index-priced contracts, and affiliate-owned mines to meet the fuel needs of its coal-fired generating plants. The overall decrease in coal-fuel expense in this filing has been primarily driven down by reduced coal volumes, as shown in Confidential Table 2 above. PacifiCorp's fixed price coal contracts have continued to benefit customers as natural gas and power prices rise. However, the demand and cost for coal has increased both nationally and globally, and PacifiCorp continues to work with its coal suppliers and mines to ensure the best pricing for the benefit of our customers.

Q. Does this conclude your direct testimony?

A. Yes.

REDACTED
Docket No. UE 400
Exhibit PAC/201
Witness: James Owen

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED

Exhibit Accompanying Direct Testimony of James Owen

Naughton Coal Supply Agreement Analysis

March 2022

THIS ATTACHMENT IS HIGHLY CONFIDENTIAL IN ITS ENTIRETY AND IS PROVIDED UNDER SEPARATE COVER

REDACTED
Docket No. UE 400
Exhibit PAC/202
Witness: James Owen

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED

Exhibit Accompanying Direct Testimony of James Owen

Bridger Coal Company Costs

March 2022

THIS ATTACHMENT IS CONFIDENTIAL IN ITS ENTIRETY AND IS PROVIDED UNDER SEPARATE COVER

Docket No. UE 400
Exhibit PAC/300
Witness: Daniel J. MacNeil

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Direct Testimony of Daniel J. MacNeil

March 2022

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I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name, business address, and present position with PacifiCorp d/b/a Pacific Power (PacifiCorp or Company).

A. My name is Daniel J. MacNeil. My business address is 825 NE Multnomah Street, Suite 600, Portland, Oregon 97232. My title is Commercial Analytics Adviser.

Q. Briefly describe your education and professional experience.

A. I received a Master of Arts degree in International Science and Technology Policy from George Washington University and a Bachelor of Science degree in Materials Science and Engineering from Johns Hopkins University. Before joining the Company, I completed internships with the United States Department of Energy's Office of Policy and International Affairs and the World Resources Institute's Green Power Market Development Group. I have been employed by the Company since 2008, first as a member of the net power costs group, then as manager of that group from June 2015 until September 2016. In my current role, I provide analytical expertise on a broad range of topics related to the Company's resource portfolio and obligations, including oversight of the calculation of avoided cost pricing in the Company's jurisdictions.

Q. Have you testified in previous regulatory proceedings?

A. Yes. I have provided testimony in California, Idaho, Oregon, Utah, Wyoming, and Federal Energy Regulatory Commission (FERC) dockets.

II. PURPOSE AND SUMMARY OF TESTIMONY

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

A. I provide details on the development of the regulation reserve requirements included in the production cost modeling for the 2023 Transition Adjustment Mechanism (TAM).

Q. Please summarize your testimony.

A. The regulation reserve requirements used in the 2023 TAM reflect the methodology developed in PacifiCorp's 2021 Integrated Resource Plan (IRP).[1] Regulation reserves are intended to cover deviations between forecasted load and resources and actual load and resources, and represent intra-hour flexible resources necessary to comply with applicable reliability standards that wouldn't otherwise be captured within an hourly production cost model. The methodology produces hourly reserve requirement values for the PacifiCorp East (PACE) and PacifiCorp West (PACW) balancing authority areas (BAAs) that are specific to the portfolio of resources in the 2023 TAM study period.

The regulation reserve methodology is based on compliance with the North American Electric Reliability Corporation (NERC) Control Performance Criteria in BAL-001-2, as discussed in the section entitled "Reliability Standards."[2] Historical results provide the best available source of deviation information for load and various resource types, and PacifiCorp's analysis is based on two years of history, 2018-2019.

[1] 2021 Integrated Resource Plan. Volume II, Appendix F: Flexible Reserve Study, *available at* https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2021-irp/Volume%20I%20-%209.15.2021%20Final.pdf.
[2] NERC Standard BAL-001-2 – Real Power Balancing Control Performance: www.nerc.com/files/BAL-001-2.pdf.

The data used in the analysis is discussed in the section entitled "Collection of Data and Historical Deviations." Compliance with BAL-001-2 involves a rolling view of the deviations between hourly forecasts and actual output. These calculations are described in the section entitled "Reliability Compliance Requirements."

While BAL-001-2 requires 100 percent compliance in all intervals, PacifiCorp does not need to compensate for the entire deviation in every interval. For example, PacifiCorp does not need to reduce its deviations when they are helping to maintain the frequency of the Western Interconnection as a whole. This reduces PacifiCorp's regulation reserve need, as discussed in the section entitled "Acceptable Deviations".

PacifiCorp's long-term resource planning includes the assumption that a small risk of resource shortfalls is reasonable, as the costs of guaranteeing operation under all possible conditions would be cost-prohibitive. A similar assumption is made in PacifiCorp's regulation reserve analysis, that firm load could be curtailed very rarely to maintain the required 100 percent compliance with the BAL-001-2 standard. This reduces the regulation reserve requirement, as discussed in the section entitled "Planning Reliability Target."

The regulation reserve requirement is intended to comply with standard BAL-001-2, minimize the regulation reserve held, and use data available when forecasts and resource schedules are submitted prior to the operating hour. PacifiCorp used a quantile regression analysis to align regulation reserve requirements with the risk specific to the forecasted load and resource output. By tailoring the forecast to the risk in the upcoming hour, the regulation reserve requirements are reduced, as discussed in the section entitled "Regulation Reserve Requirement Forecast."

By using a single pool of regulation reserve resources to balance the aggregate deviations of load and a variety of resources, PacifiCorp is able to maintain reliability with lower quantity of regulation reserves than would be required if load and each resource type were balanced independently. In a similar way, pooling flexible resources with other Energy Imbalance Market (EIM) participants allows PacifiCorp to further reduce its regulation reserve requirements. The sections entitled "Portfolio Diversity Benefit" and "EIM Diversity Benefit" discuss how the regulation reserve forecast has been reduced to account for these aspects of PacifiCorp's operations.

Finally, PacifiCorp recognizes that its regulation reserve requirements are dependent on its resource portfolio, and that new wind and solar resources have been added to its portfolio since the 2018-2019 historical period. To account for this, and other potential resource changes over the 2021 IRP study horizon, PacifiCorp calculated the portfolio diversity benefits specific to a wide range of wind and solar capacity combinations. These results are used to identify reserve requirements specific to assumptions used in the 2023 TAM study period, as discussed in the section entitled "Portfolio Regulation Reserve Requirements."

III. REGULATION RESERVE REQUIREMENTS

A. Reliability Standards

Q. What is regulation reserve?

A. In order to ensure reliable operation of the bulk electric system, PacifiCorp must continuously balance the load demand and generation output within the PACE and PACW BAAs. Regulation reserve is a component of operating reserve, which NERC defines as "the capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages and local area protection."[3] Regulation reserve is capacity that PacifiCorp holds available to ensure compliance with the NERC Control Performance Criteria in BAL-001-2.[4]

Q. Please describe NERC Standard BAL-001-2.

A. NERC standard BAL-001-2, which became effective July 1, 2016, does not specify a regulation reserve requirement based on a simple formula, but instead requires utilities to hold sufficient reserve to meet specified control performance standards. The primary requirement relates to area control error (ACE), which is the difference between a BAA's scheduled and actual interchange, and reflects the difference between electrical generation and load within that BAA. Requirement 2 of BAL-001-2 defines the compliance standard as follows:

> *Each Balancing Authority shall operate such that its clock-minute average of Reporting ACE does not exceed its clock-minute Balancing Authority ACE Limit (BAAL) for more than 30 consecutive clock-minutes…*

In addition, Requirement 1 of BAL-001-2 specifies that PacifiCorp's Control Performance Standard 1 (CPS1) score must be greater than or equal to 100 percent for each preceding 12 consecutive calendar month period, evaluated monthly. The CPS1 score compares PacifiCorp's ACE with interconnection frequency during each clock minute. A higher score indicates PacifiCorp's ACE is helping interconnection frequency, while a lower score indicates it is hurting interconnection frequency. Because CPS1 is averaged and evaluated on a monthly basis, it does not require a response to each and every ACE event, but rather requires that PacifiCorp meet a

[3] NERC Glossary of Terms: www.nerc.com/files/glossary_of_terms.pdf, updated May 13, 2019.
[4] NERC Standard BAL-001-2 – Real Power Balancing Control Performance: www.nerc.com/files/BAL-001-2.pdf.

minimum aggregate level of performance in each month. Regulation reserve is thus the capacity that PacifiCorp holds available to respond to changes in generation and load to manage ACE within the limits specified in BAL-001-2.

Q. What are the key elements of the BAL-001-2 standard that impact PacifiCorp's need for regulation reserves?

A. There are three key elements in BAL-001-2 that drive the regulation reserve need. These elements are: (1) the length of time (or "interval") used to measure compliance; (2) the percentage of intervals that a BAA must be within the limits set in the standard; and (3) the bandwidth of acceptable deviation used to determine whether an interval is considered out of compliance. I discuss each of these elements in more detail below.

Q. What is the first key element under standard BAL-001-2?

A. The first key element is the length of time used to measure compliance. Compliance under BAL-001-2 is measured over rolling 30-minute intervals, with 60 overlapping periods per hour, some of which include parts of two clock-hours. In effect, this means that every minute of every hour is the beginning of a new, 30-minute compliance interval. If the ACE is within the allowed limits at least once in a 30-minute interval, that interval was in compliance, and only the minimum deviation in each 30-minute interval is considered in determining compliance. As a result, PacifiCorp does not need to hold regulation reserves for deviations with duration less than 30 minutes.

Q. What is the second key element under standard BAL-001-2?

A. The second key element is the compliance percentage, or the number of intervals where deviations are allowed outside the limits set in the standard. BAL-001-2 requires 100 percent compliance, so deviations must be maintained within the requirement set by the standard for all rolling 30-minute intervals. Because shortfalls are not permitted when the compliance requirement is 100 percent, this results in relatively high regulation reserve requirements based on uncommon events, rather than typical conditions, as further discussed herein.

Q. What is the third key element under standard BAL-001-2?

A. The third key element is related to the bandwidth of acceptable deviation before an interval is considered out of compliance. Under BAL-001-2, the acceptable deviation for each BAA is dynamic, varying as a function of the frequency deviation for the entire interconnect. As a result, a given deviation will be out of compliance in some periods and in compliance in other periods. As a result, the acceptable deviation for a future period cannot be known in advance.

Q. How has PacifiCorp calculated the regulation reserve required for compliance with BAL-001-2?

A. The calculations used to determine the regulation reserve required to ensure PacifiCorp's compliance with BAL-001-2 are described in more detail below. The five primary elements of the calculation are as follows:

- Collection of Data and Historical Deviations;
- Compliance Requirements;
- Acceptable Deviations: Historical Balancing Authority ACE Limit Data;

- Planning Reliability Target: Loss of Load Probability (LOLP); and
- Regulation Reserve Forecast

The regulation reserve forecast section is further broken down into specific forecasts for each type of regulation reserve contributor: load, wind, solar, and non-variable energy resources (Non-VERs). Finally, the calculation used to determine the regulation reserve forecast for the combined portfolio of all regulation reserve contributors is discussed.

B. Collection of Data and Historical Deviations

Q. Please describe the historical generation data used in PacifiCorp's analysis.

A. PacifiCorp's participation in the Western Energy Imbalance Market (EIM) results in five-minute deviation data for each generating resource in PacifiCorp's BAAs, including wind, solar, and Non-VERs. Deviations reflect the difference between actual resource output based on meter data and an hourly "base schedule" submitted to the California Independent System Operator (CAISO) during the prior hour. These deviations are used to determine energy imbalance charges (or payments) for each resource. PacifiCorp's analysis uses EIM deviation results from January 2018 through December 2019.

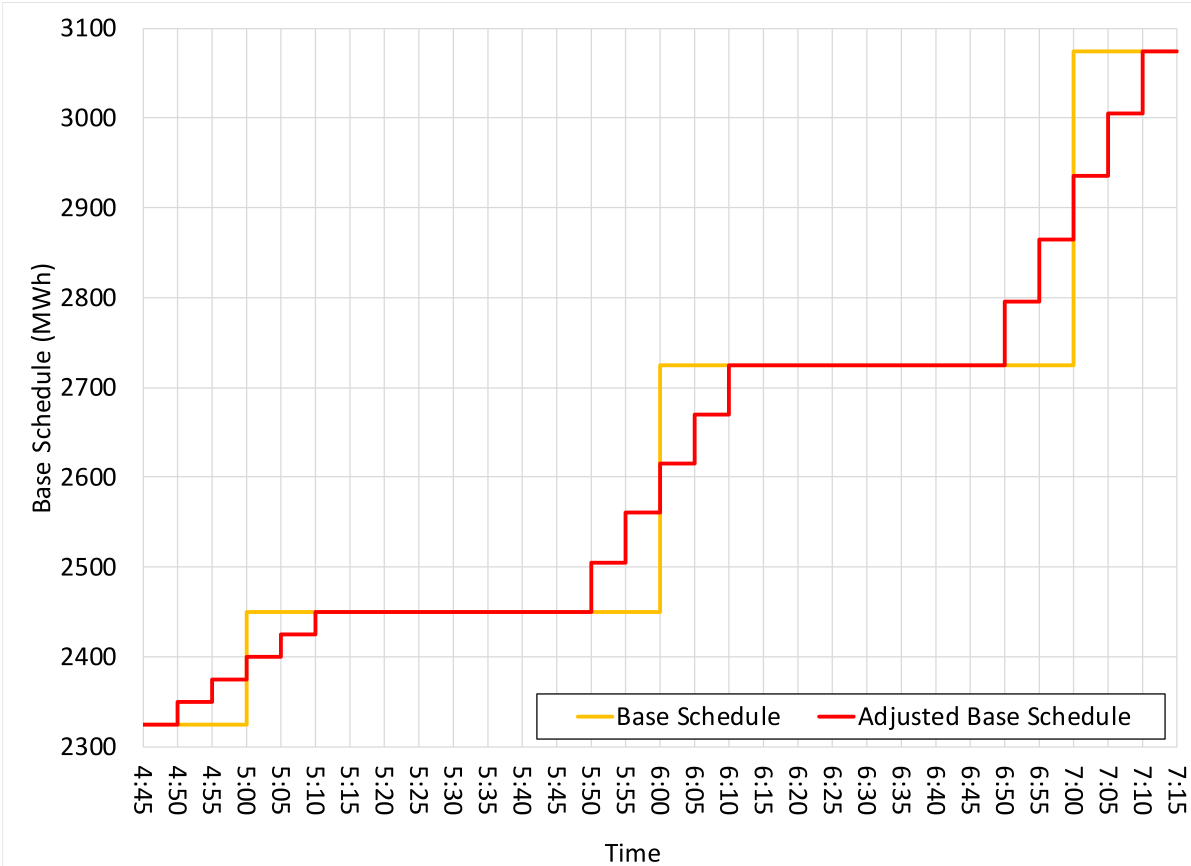
Q. Please describe the historical load data used in PacifiCorp's analysis.

A. As part of PacifiCorp's participation in EIM, the CAISO produces a forecast of the load for each PacifiCorp BAA for the upcoming hour. This forecast excludes non-conforming loads for certain industrial customers with unique patterns of demand which are forecasted and scheduled directly by PacifiCorp. Deviations for load can be calculated from the difference between this hourly forecast and PacifiCorp's actual load data for conforming loads in the PacifiCorp BAAs for each five-minute interval from its Energy Management System (EMS).

Q. Did PacifiCorp make any adjustments to the historical load data to better reflect operational practices?

A. Yes. PacifiCorp incorporated a "base schedule ramp adjustment." In actual operations, PacifiCorp's ACE calculation includes a linear ramp from the base schedule in one hour to the base schedule in the next hour, starting 10 minutes before the hour and continuing until 10 minutes past the hour. The hourly base schedules used in the analysis are adjusted to reflect this transition from one hour to the next. This adjustment step is important because, to the extent actual load or generation is transitioning to the levels expected in the next hour, the adjusted base schedules will result in reduced deviations during these intervals, potentially reducing the regulation reserve requirement. Figure 1 below illustrates the base schedule ramping adjustment.

Figure 1: Illustration of Base Schedule Ramping Adjustment



Q. Was the source data adjusted to remove the impacts of abnormal weather conditions?

A. No. The full range of weather conditions experienced during the study period remain in the source data, as these conditions are indicative of the range of weather conditions PacifiCorp expects to experience going forward. Including the full range of weather conditions also complies with the guidance from FERC's Order No. 764 that weather "diversity events" should be included in the data set so that the quantity and costs of such reserves are more reflective of actual system operations.[5]

[5] FERC Order No. 764 at P 321.

Q. Did PacifiCorp exclude periods with data irregularities unrelated to actual regulation reserve requirements?

A. Yes. The raw data extracted from PacifiCorp's systems was reviewed to identify potentially spurious data points prior to performing the regulation reserve requirement calculations discussed below. The following types of data irregularities were observed and the associated periods were excluded from the analysis.

Load:

- Telemetry spike/poor connection to meter (< 1 hour)
- Missing meter data (< 1 hour)
- Missing base schedules (82 hours)

Q. Did PacifiCorp make any other adjustments to the historical data?

A. Yes. The available wind data includes wind curtailment events which affect metered output. When these curtailments occur, the CAISO sends data, by generator, indicating the magnitude of the curtailment. This data is layered on top of the actual meter data to develop a proxy for what the metered output would have been were the generator not curtailed. Regulation reserve requirements are calculated based on the shortfall in actual output relative to base schedules. By adding back curtailed volumes to the actual metered output, the shortfall relative to base schedules is reduced, as is the regulation reserve requirement. This is reasonable since the curtailment is directed by the CAISO or the transmission system operator to help maintain reliable operation, so it should not exacerbate the calculated need for regulation reserves.

C. Reliability Compliance Requirements

Q. How are the adjusted historical deviations used to develop the BAL-001-2 compliance requirements in each interval?

A. First, the minimum five-minute imbalance was calculated for each 30-minute rolling period in the study period. Second, for each hour, the maximum five-minute imbalance was selected from the values identified in the first step. These two calculations are explained in more detail below.

Q. Why is the minimum imbalance calculated for each 30-minute interval?

A. NERC standard BAL-001-2 requires that a balancing authority's ACE not exceed the specified limit for more than 30 consecutive minutes. In other words, compliance can be maintained by operating within the specified limit once in each rolling 30-minute interval, and the requirement is lowest if this occurs in the interval with the smallest deviation. Using the minimum imbalance thus ensures that compliance can be achieved in at least the one interval in which that minimum occurred.

Q. Why is the maximum imbalance from all rolling 30-minute intervals calculated for each hour?

A. All PacifiCorp transmission customers submit hour-ahead base schedules for the resources needed to serve their load by 57 minutes before the operating hour (T-57). The maximum capacity that may be used as operating reserve at any time during the upcoming hour needs to be identified and set aside so that it is not utilized in the base schedules for resources serving PacifiCorp's loads, which are also submitted at T-57. While there is an opportunity to adjust resource base schedules up to T-40, this is limited to identifying resources necessary to meet any changes to expected requirements. Therefore, the regulation reserve forecast identifying the quantity of operating reserves to be set aside for use at any time during the upcoming hour needs to be finalized by T-57. As a result, the 30-minute rolling interval with the largest minimum imbalance establishes the reserves that must be set aside for the entire hour.

Q. How does the thirty-minute compliance timeframe under BAL-001-2 interact with base schedule submission at T-57?

A. The 30-minute compliance timeframe for BAL-001-2 can reduce the regulation reserve requirement associated with deviations in the last few intervals of each hour. This period has the longest forecast horizon (i.e., the furthest out from T-57), so the potential deviations are expected to be larger. However, if the change resulting in the deviation is reflected in the base schedule for the next hour, PacifiCorp's ACE will return to zero on its own a few minutes later. Thus, so long as the duration of the deviation is less than 30 minutes, any deviation in the last few intervals will not require additional regulation reserve to ensure compliance with BAL-001-2. Because compliance will occur on its own within 30 minutes, regulation reserve requirements are reduced.

D. Acceptable Deviations: Historical Balancing Authority ACE Limit

Q. Does a violation of BAL-001-2 necessarily occur if a 30-minute sustained deviation exceeds the regulation reserve capability available?

A. No. A violation does not occur unless the deviation also exceeds the Balancing Authority ACE Limit.

Q. Please describe the Balancing Authority ACE Limit.

A. The Balancing Authority ACE Limit is specific to each BAA and is dynamic, varying as a function of interconnection frequency. When WECC frequency is close to 60 hertz (Hz), the Balancing Authority ACE Limit is large and large deviations in ACE are allowed. As WECC frequency drops further and further below 60 Hz, ACE deviations are increasingly restricted for BAAs that are contributing to the shortfall, i.e., those BAAs with Net Actual Interchange less than Net Scheduled Interchange. A BAA commits a BAL-001-2 reliability violation if in any 30-minute interval it does not have at least one minute when its ACE is within its Balancing Authority ACE Limit.

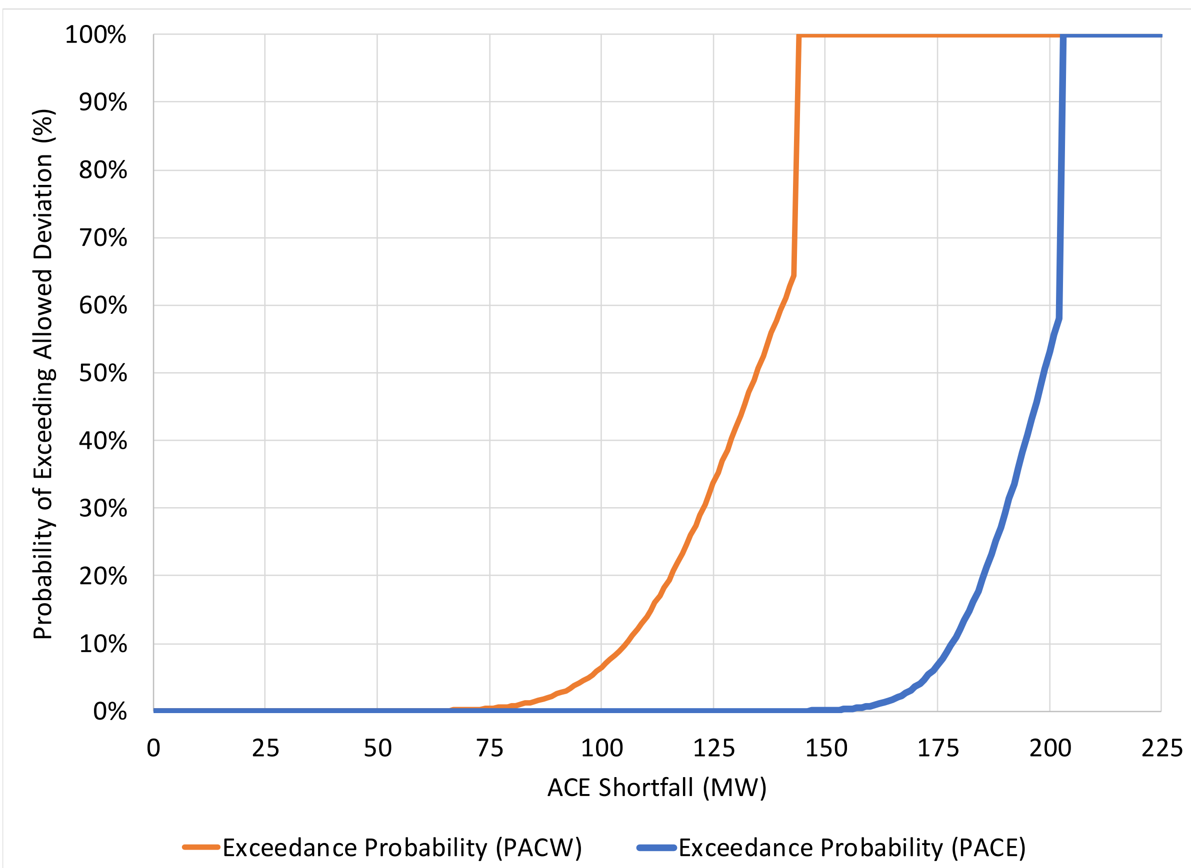
WECC-wide frequency can change rapidly and without notice, and this causes large changes in the Balancing Authority ACE Limit over short time frames. Maintaining ACE within the Balancing Authority ACE Limit under those circumstances can require rapid deployments of large amounts of operating reserve. To limit the size and speed of resource deployment necessitated by variation in the Balancing Authority ACE Limit, PacifiCorp's operating practice caps permissible ACE at the lesser of the Balancing Authority ACE Limit or four times L_{10}.[6] L_{10} represents a bandwidth of acceptable deviation under the former BAL-001 standard (BAL-001-1) prescribed by WECC between the net scheduled interchange and the net actual electrical interchange of PacifiCorp's BAAs.

[6] L_{10} is a BAA-specific bound on ACE that varies as a function of the targeted frequency bound for the interconnection and the frequency bias setting specific to that BAA. The L_{10} for PacifiCorp's BAAs in 2019 were approximately 31.9 megawatts (MW) for the PACW BAA and 48.8 MW for the PACE BAA. For more information, please refer to: https://www.nerc.com/comm/OC/BAL0031_Supporting_Documents_2017_DL/BAL-003_Frequency_Bias_Settings_02Jul19.pdf.

Q. If the Balancing Authority ACE Limit is dynamic and not known in advance, how can it be used to develop a regulation reserve forecast?

A. While the specific Balancing Authority ACE Limit for a given interval cannot be known in advance, the historical probability distribution of Balancing Authority ACE Limit values is known. The following figure shows the probability of exceeding the allowed deviation during a five-minute interval for a given level of ACE shortfall, up to the cap of four times L_{10}. For instance, an 82 MW ACE shortfall in PACW had a one percent chance of exceeding the Balancing Authority ACE Limit in 2018-2019.

Figure 2: Probability of Exceeding Allowed Deviation



Q. Is there a link between PacifiCorp's deviations and the Balancing Authority ACE Limit?

A. Yes. Resource shortfalls in the PacifiCorp BAAs contribute to reductions in WECC-wide frequency, which in turn reduces the Balancing Authority ACE Limit. However, in the study period, PacifiCorp's deviations and Balancing Authority ACE Limits were uncorrelated, which indicates that PacifiCorp's contribution to WECC-wide frequency is small. PacifiCorp's deviations and Balancing Authority ACE Limits were also uncorrelated when periods with large deviations were examined in isolation. If PacifiCorp's large deviations made distinguishable contributions to the Balancing Authority ACE Limit, ACE shortfalls would be more likely to exceed the Balancing Authority ACE Limit during large deviations. Since this is not the case, the probability of exceeding the Balancing Authority ACE Limit is lower, and fewer regulation reserves are necessary to comply with the BAL-001-2 standard, which benefits customers.

E. Planning Reliability Target: Loss of Load Probability

Q. Does a violation of BAL-001-2 necessarily occur if a 30-minute sustained deviation exceeds the regulation reserve capability available by more than the Balancing Authority ACE Limit?

A. Not necessarily. As a last resort, PacifiCorp may curtail firm load to reduce the resource shortfall to a level below the Balancing Authority ACE Limit.

Q. Is curtailment of firm load a typical component of resource planning?

A. Yes. When conducting resource planning, it is common to use a reliability target that assumes a specified Loss of Load Probability (LOLP). The LOLP that many planners use is a "1-day-in-10-years" metric. An electric system using a 1-day-in-10 years LOLP will plan its system to maintain sufficient capacity (i.e., through a planning reserve margin) such that system peak load is not likely to exceed available supply (i.e., load is lost) more than once in a 10-year period. If the system is planned correctly under this metric, the electric system is considered to be a "reliable" system and the probability of load exceeding supply becomes highly improbable. However, the 1-day-in-10-years planning standard accepts that in a reliably planned electric system, firm load might be curtailed in rare circumstances, rather than acquiring resources for extremely unlikely events. Under the most-restrictive interpretation, 1-day-in-10-years would require reliable operation for nine years and 364 days out of a 10-year period, and would allow capacity shortfalls to occur on a single day. Under a less-restrictive interpretation, one day can be expressed as 24 hours, which would allow capacity shortfalls to occur in up to 24 hours spread across 10 years. PacifiCorp's analysis uses this less-restrictive "loss of load hours" interpretation.

Q. What does the term "loss of load hours" (LOLH) mean?

A. LOLH is a count of the expected (mean) number of hours in which load exceeds available resources over the course of a given year. Hypothetically, a system using the 1-day-in-10-years LOLP can meet that standard by planning its system to ensure that load does not exceed generation during more than 2.4 hours per year. The 2.4 LOLH is calculated by dividing a single day (24 hours) by the 10 years of the LOLP.

Q. What reliability target has PacifiCorp used in its analysis?

A. PacifiCorp's 2019 IRP included an analysis of regulation reserve requirements that was similar to that conducted here.[7] In that analysis, which produced inputs used to support resource selection for long-term portfolio analysis, regulation reserve shortfalls were allowed up to 0.50 LOLH per year.[8] PacifiCorp's 2019 IRP also includes a planning reserve margin study which assesses the risk of loss of load due to variations in load, thermal unit availability, and hydro conditions.[9] That study identified a planning reserve margin of 13 percent of coincident peak load, concluding that 1.06 LOLH per year from those causes was acceptable for planning purposes and reasonably balanced capacity costs with the risk of loss of load occurring. The 1.06 LOLH value related to PacifiCorp's ability to serve its retail load is in addition to the risk associated with regulation reserve shortfalls and outages customers might experience as a result of transmission and distribution system events. As a result, the regulation reserve shortfall represents a portion of the risk faced by PacifiCorp's retail customers. Accordingly, PacifiCorp's reserve study assumes that the same 0.50 LOLH per year due to regulation reserve shortages used in its 2019 IRP is also appropriate for determining regulation reserve requirements used in the 2023 TAM. By assuming firm load can be curtailed in up to 0.50 hours per year, the quantity of regulation reserve needed to maintain the required 100 percent compliance with the BAL-001-2 standard and the Balancing Authority ACE Limit is

[7] PacifiCorp 2019 Integrated Resource Plan Report, Vol. I at 16, 20; available at: https://www.pacificorp.com/energy/integrated-resource-plan.html.
[8] Id., Vol. II, Appendix F – Flexible Reserve Study at 77.
[9] Id., Vol. II, Appendix I – Planning Reserve Margin Study at 137.

reduced from the level that would be required if reserves held were required to meet or exceed the regulation reserve need in all intervals.

Q. Is curtailment of firm load a typical component of system operations?

A. No. I have been discussing certain planning standards and presumptions. In real-time operations, curtailment of firm load would only occur as a last resort when all available alternatives had been utilized and a reliability violation was imminent. PacifiCorp has not curtailed firm load because of ACE or operating reserve shortfalls in the past 10 years. PacifiCorp must maintain compliance with the BAL standards at all times and BAL-001-2 does not allow for exceptions based on planning assumptions. As a result, the study is likely understating the quantity of regulation reserve held by PacifiCorp and used to provide reliable service since it allows for loss of load events in excess of what has actually occurred in the past several years. Nonetheless, primarily for ratemaking purposes, PacifiCorp has incorporated the 0.5 LOLH into its regulation reserve study, and, from the perspective of customers, it has a beneficial effect of lowering the regulation reserve requirement and associated rates.

Q. How is the reliability target applied in PacifiCorp's analysis?

A. If the regulation reserve available is greater than the regulation reserve requirement for an hour, the LOLP is zero percent for that hour. If the regulation reserve held is less than the amount needed, the LOLP is derived from the Balancing Authority ACE Limit probability distribution. As the magnitude of the shortfall increases, the probability of exceeding the Balancing Authority ACE Limit increases. For instance, as indicated above, an 82 MW ACE shortfall in PACW has a one percent chance of exceeding the Balancing Authority ACE Limit. A one percent probability of failing to meet the Balancing Authority ACE Limit in one hour is 0.01 LOLH. A one percent probability of failing to meet the Balancing Authority ACE Limit in 50 hours over the course of a year would be 0.5 LOLH per year and corresponds to the targeted level of reliability.

F. Regulation Reserve Requirement Forecast

Q. What are the goals of the regulation reserve requirement forecast?

A. The regulation reserve requirement forecast methodology is intended to achieve the following goals:

- Compliance with standard BAL-001-2;
- Minimize regulation reserve held; and
- Use data available at the time of base schedule submission at T-57.

Q. How do the components discussed in the previous sections relate to the regulation reserve requirement?

A. The regulation reserve requirement is first compared to the hourly compliance requirement to determine the magnitude of the shortfall in each hour, if any. Next, the LOLP associated with each hour that has a shortfall is calculated from the Balancing Authority ACE Limit probability distribution. Finally, if the cumulative LOLP over all hours with shortfalls in the year is less than the reliability target, the regulation reserve requirement is deemed sufficient to comply with BAL-001-2.

Q. How do the other two goals (i.e., minimize regulation reserve held and use data available at time of base schedule submission at T-57) impact the regulation reserve requirement?

A. Ideally, PacifiCorp would never hold more than the minimum regulation reserve required in any hour. However, requirements vary widely, and it is not possible to predict the exact requirement for an upcoming hour. Despite this, if information available at T-57 can be used to reliably distinguish between periods when requirements are likely to be low and periods when requirements are likely to be high, then fewer regulation reserves will be necessary to achieve a given reliability target.

Q. What data is available to inform the calculation of the regulation reserve requirements?

A. The base schedule reflects the best, most up-to-date information about conditions in the upcoming hour as of T-57.

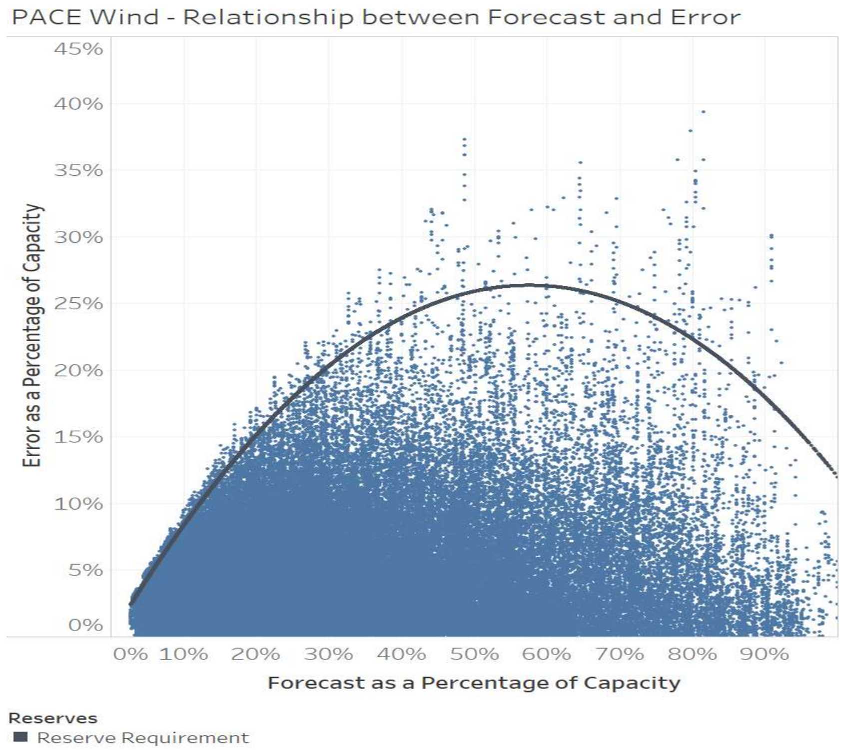
Q. How were the regulation reserve requirements developed?

A. Regulation reserve requirements were developed using quantile regression, which is a type of regression analysis. Stated simply, a regression analysis attempts to predict the value of one variable (the response variable) on the basis of one or more variables (predictor variable). A typical regression results in estimates of the conditional mean (i.e., the 50th percentile) of the response variable given certain values of the predictor variables. A quantile regression estimates other specified percentiles (e.g., 25th percentile, 95th percentile, etc.) of the response variable. For PacifiCorp's regulation reserve study, the response variable is the reserve requirement, calculated from the deviation between the hour-ahead forecast and the actual metered output. The predictor variable is the hour-ahead forecast. The study's quantile regressions employ polynomial functions that cover a targeted percentile of all historical deviations.

Q. Were quantile regressions prepared for separately for load and different resource types?

A. Yes. The forecast and deviations specific to each type are used to calculate a reserve requirement for each hour. The targeted percentile in the quantile regression for each type is calculated such that the hourly reserve requirement achieves the annual reliability target of 0.5 hours per year, after accounting for the dynamic Balancing Authority ACE Limit. These are stand-alone reserve requirements for load and each resource type, in the absence of any diversity benefits from using a shared regulation reserve supply to meet system requirements. Figures 3 to 10 below illustrate the relationship between the regulation reserve requirement, the historical forecast error and the forecasted level of output stated as a capacity factor (i.e., a percentage of the nameplate VERs capacity) for load and each resource type in PACE and PACW during the study period.

1 **Figure 3: PACE Wind**



2 **Figure 4: PACW Wind**

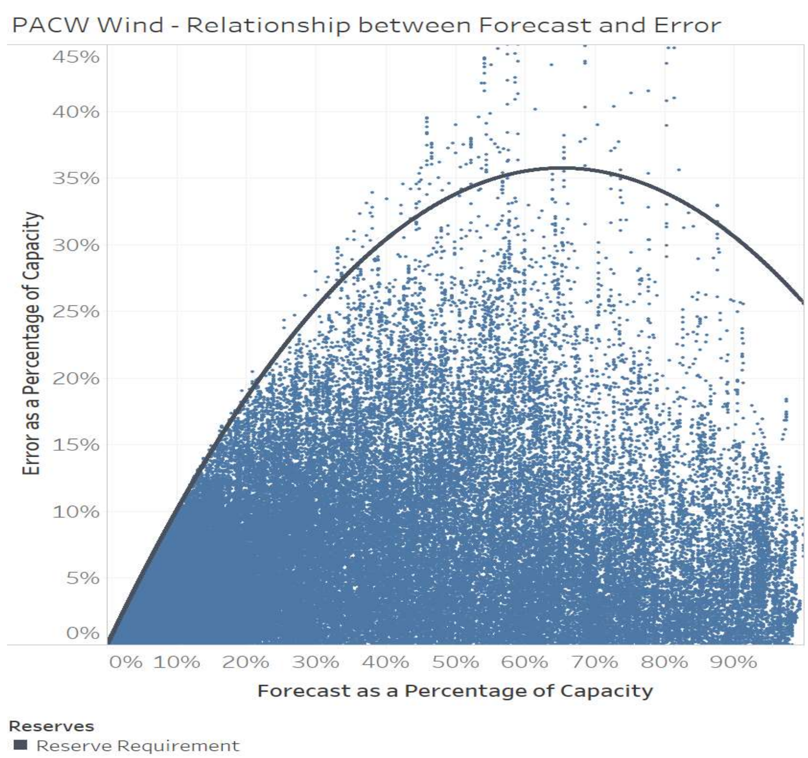


Figure 5: PACE Solar

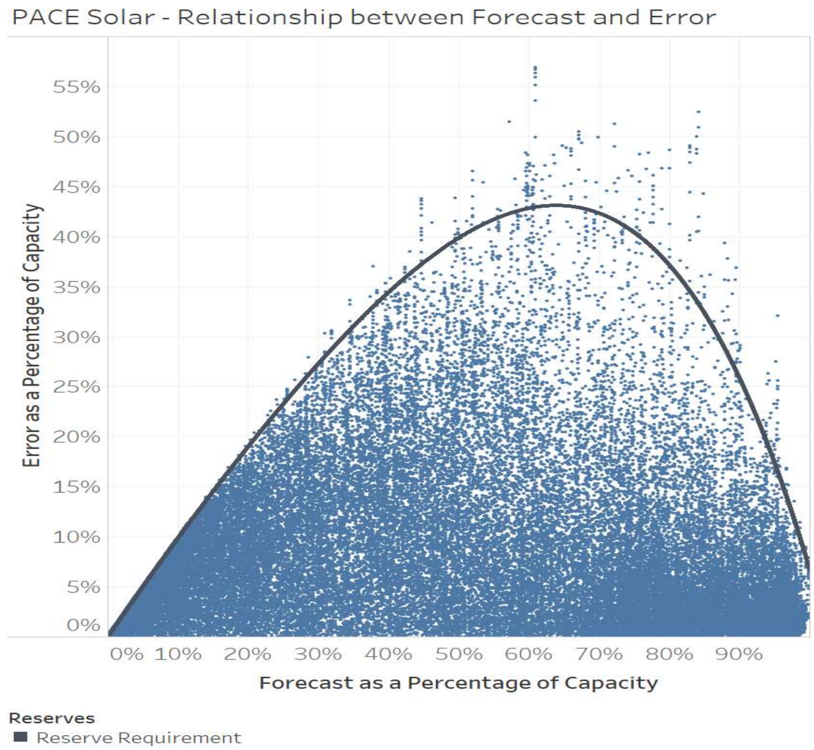
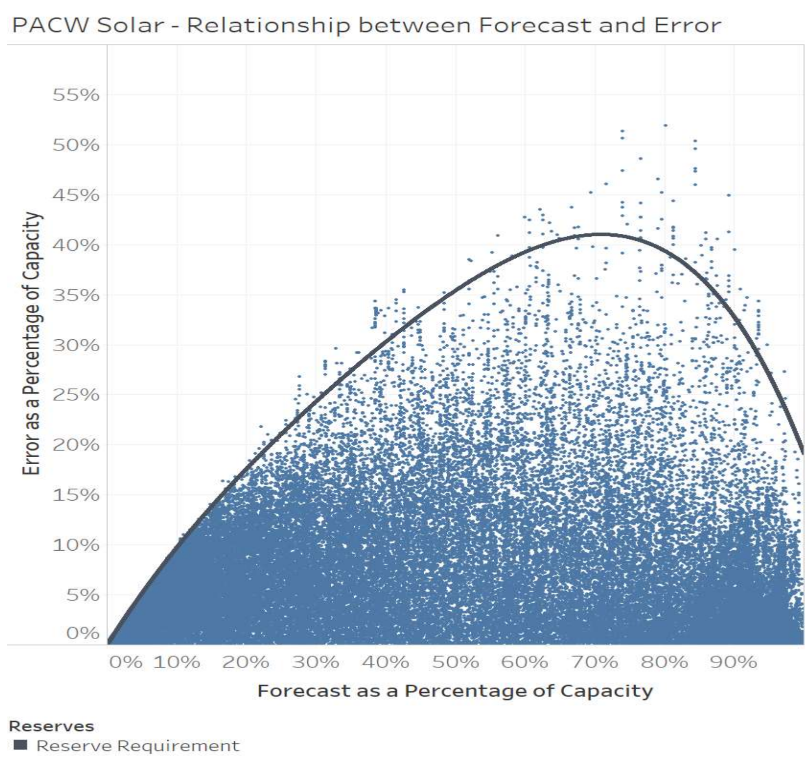
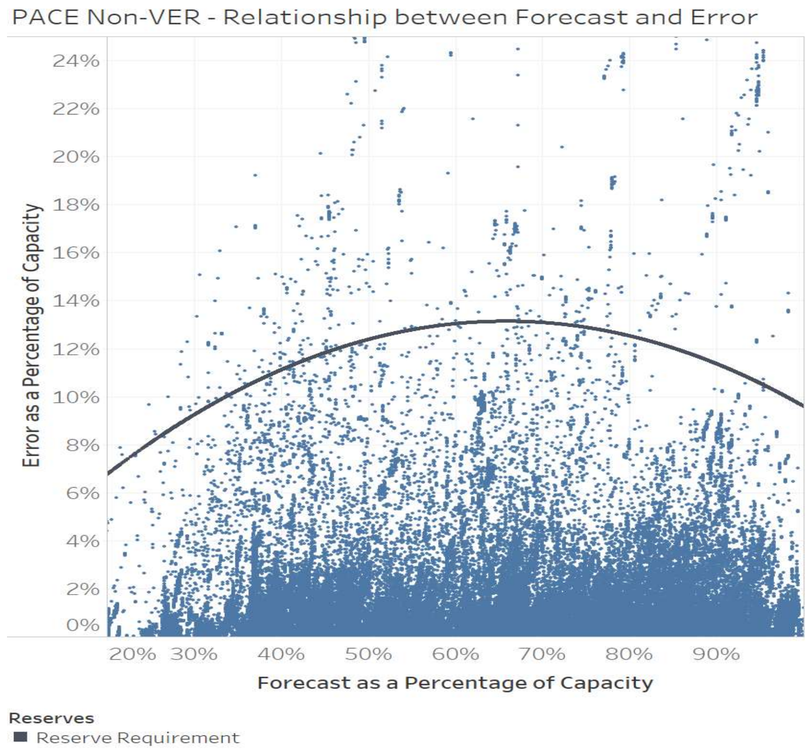


Figure 6: PACW Solar



1 **Figure 7: PACE Non-VER**



2 **Figure 8: PACE Non-VER**

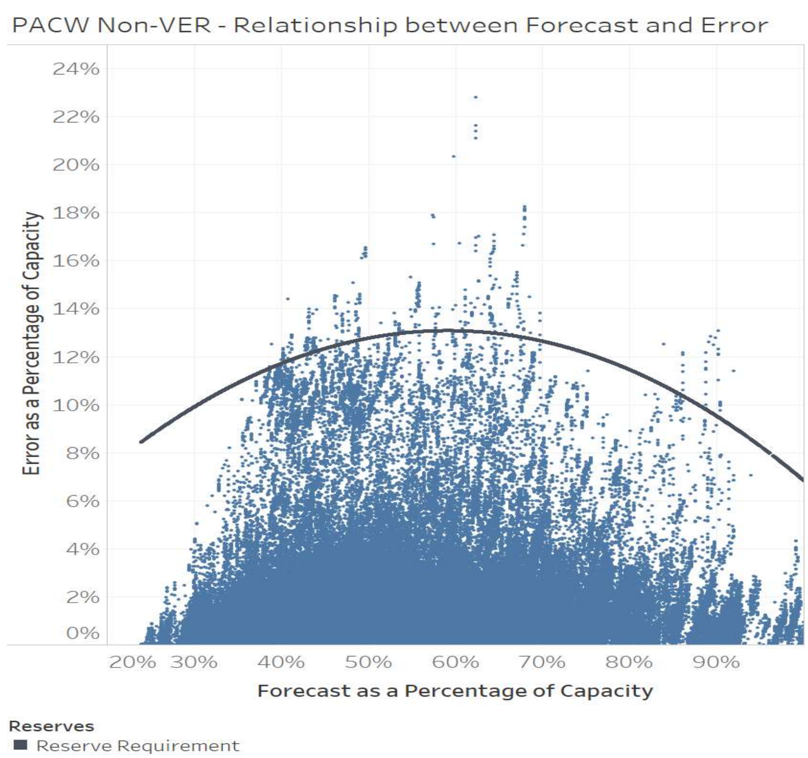


Figure 9: PACE Load

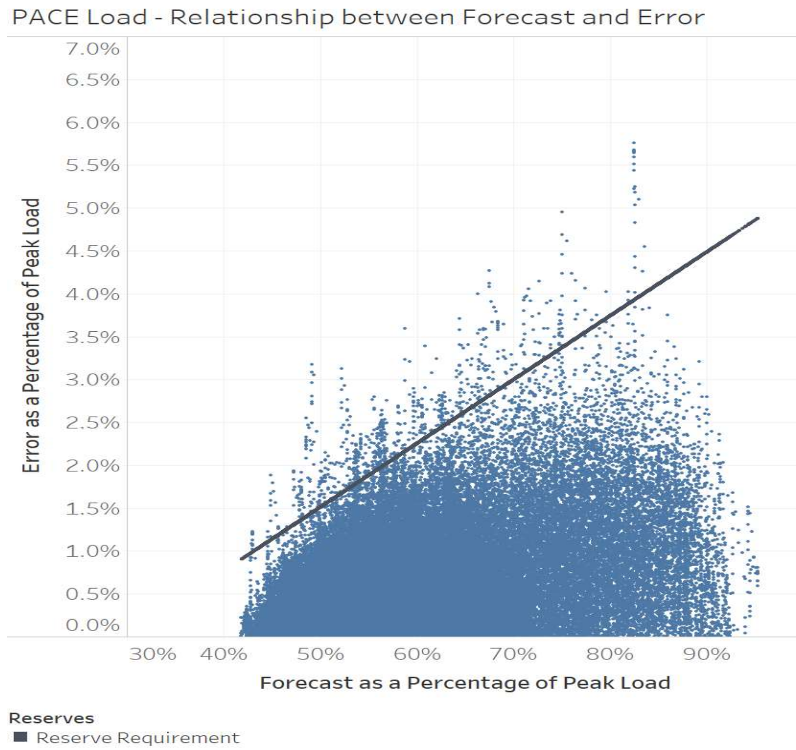
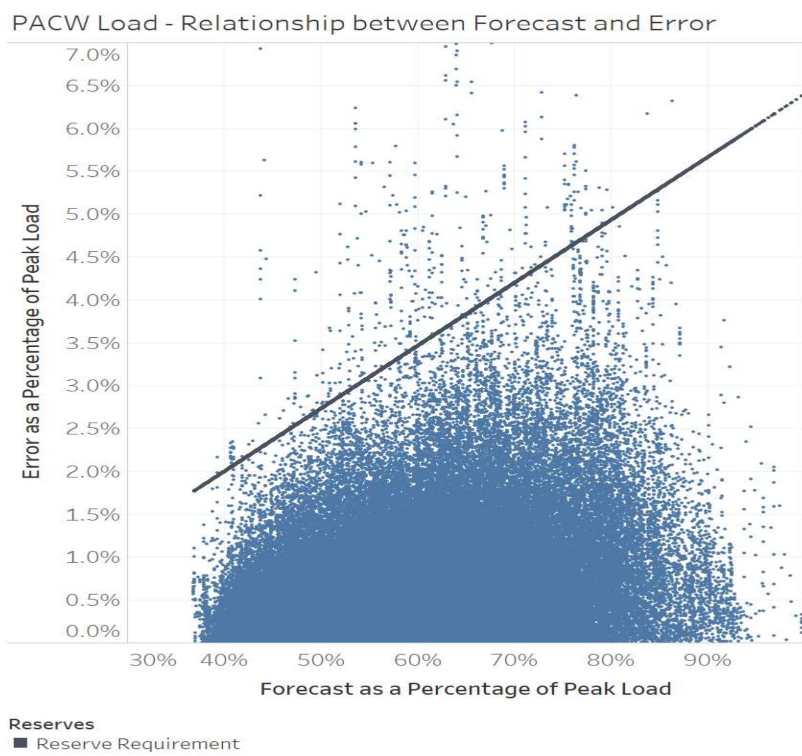


Figure 10: PACW Load



Q. What are the results of the regulation reserve requirements?

A. The quantile regression analysis results are shown in Table 1 below. These requirements do not account for any portfolio diversity benefits from combining the deviations across load and various resource types.

Table 1: Summary of Stand-alone Regulation Reserve Requirements

Scenario	Stand-alone Regulation Forecast (aMW)	Capacity (MW)	Stand-alone Regulation Forecast (%)
Non-VER	106	1,304	8.2%
Load	334	10,094	3.3%
Wind	457	2,745	16.7%
Solar	159	1,080	14.8%
Total	**1,057**		

G. Portfolio Diversity Benefit

Q. How did PacifiCorp account for portfolio diversity benefits?

A. The regulation reserve study accounts for diversity benefits attributable to the diverse users of PacifiCorp's system through an iterative process that starts with a calculation of the aggregate system-wide deviations. Because the largest deviations from each type of resources and load are not likely to occur at the same time, the regulation reserves held can cover the expected deviations for multiple types at once and a reduced total quantity of reserves is sufficient to maintain the desired level of reliability. This reduction in the reserve requirement is the diversity benefit from holding a single pool of reserves on PacifiCorp's system to cover deviations by a variety of resources and load.

Q. Is there an interaction between the regulation reserve requirements for load and various resource types?

A. Yes. The stand-alone regulation reserve forecasts described above (459 MW for wind, 160 MW for solar, 107 MW for Non-VERs, and 336 MW for load) independently ensure that the probability of a reliability violation for load and each resource type remains within the reliability target. However, the largest deviations tend not to occur simultaneously, and in some cases load and different resources will have offsetting deviations. As a result, while the sum of the stand-alone reserve requirements yields a total reserve requirement of 1057 MW, the total portfolio requirement when all deviations are combined is only 679 MW. This 36 percent reduction in the reserve requirement still achieves the reliability target of 0.50 LOLH per year. Because the regulation reserves held cover the expected deviations for multiple sources at once, a reduced total quantity of reserves is sufficient to maintain the desired level of reliability.

H. EIM Diversity Benefit

Q. How does participation in the EIM assist PacifiCorp in fulfilling its reliability obligations?

A. In addition to the increased system visibility provided by EIM participation, EIM imports from other participating BAAs can help balance PacifiCorp's loads and resources within an hour, reducing the size of reserve shortfalls and the likelihood of a Balancing Authority ACE Limit violation.

While substantial EIM imports do occur in some hours, it is only appropriate to rely on PacifiCorp's share of the reserve benefits associated with EIM, as these are derived from the structure of the EIM rather than resources contributed by other participants. These benefits are analogous to the portfolio diversity benefits from sharing reserve resources among the resources and load in PacifiCorp's BAAs, but instead reflect the sharing of reserve resources with other BAAs across the EIM footprint. The sharing of reserves through EIM is referred to as the EIM diversity benefit.

Q. How does PacifiCorp account for the EIM diversity benefit?

A. Using historical EIM diversity benefits, a matrix of average EIM diversity benefits was calculated by hour and season. These diversity benefits are applied as a credit to the final BAA regulation reserve requirement in each hour of the study.

Q. Could the EIM result in a higher reserve obligation?

A. It is possible under certain circumstances. In order to participate fully in EIM, each participating BAA must pass a flexible ramp sufficiency test demonstrating that it has a minimum level of resources necessary to compensate for ramping or uncertainty in the requirements across the next hour. The uncertainty component is somewhat analogous to the estimate of regulation reserve requirements in PacifiCorp's study, while the ramping component is mostly incremental. The flexible ramp sufficiency test is used by the CAISO to facilitate market operation and fairness and is not intended to ensure reliable system operation, for which all EIM participating BAAs remain individually responsible.

In the current study, PacifiCorp's forecasted reserve requirements were never lower than CAISO's flexible ramp sufficiency test's requirement, but this test could be an issue if LOLH were set to allow a lower level of reliability.

Q. What is the impact of including the EIM diversity benefit in the regulation reserve analysis?

A. Including the EIM diversity benefit results in an average regulation reserve requirement of 540 MW. Reducing the PacifiCorp portfolio reserve requirement without the EIM diversity benefits by 139 MW, or an additional 20 percent reduction (after taking into account the portfolio diversity benefit).

I. Portfolio Regulation Reserve Requirements

Q. Did the Company develop a process to modify regulation reserve requirements to account for changes in wind and solar capacity over time?

A. Yes. The locations that have been identified as likely sites for future wind and solar additions are in relatively close proximity to existing wind and solar resources: wind mostly in eastern Wyoming and solar mostly in southern Utah and southern Oregon. Future resources added in close proximity to existing resources are likely to have lower than average diversity for that type of resource. Given the sizeable sample of existing wind and solar resources in PACE and PACW, maintaining the existing level of diversity as particular type of resource doubles or quadruples is a reasonable assumption. With that in mind, the PacifiCorp analysis assumes that wind, solar, and load deviations scale linearly with capacity increases from the actual data in the 2018-2019 historical period.

Q. Does the composition of the Company's portfolio impact still have an opportunity to influence portfolio diversity?

A. Yes. While the relative diversity of each resource type is not expected to change significantly, there is the opportunity for greater diversity among the wind, solar, and load requirements. These portfolio-related benefits are inherently tied to the portfolio as a whole, so it is appropriate that they vary with the portfolio. To that end, PacifiCorp has calculated the portfolio diversity benefits specific to a wide variety of wind and solar capacity combinations, rather than relying upon the portfolio diversity value associated with the historical resource mix.

Q. Does the portfolio diversity calculation incorporate changes related to EIM?

A. Yes. As part of the portfolio diversity calculation, the analysis assumes that minimum EIM flexible reserve requirements and EIM diversity benefits scale with changes in portfolio capacity. EIM minimum flexible reserve requirements are tied to the uncertainty in PacifiCorp's requirements, which grow with changes in portfolio capacity, so it would be impacted directly. EIM diversity benefits reflect PacifiCorp's share of stand-alone requirements relative to those of the rest of the BAA's participating in EIM. All else being equal, increases in PacifiCorp's portfolio capacity would result in a greater proportion of the EIM diversity benefits being allocated to PacifiCorp.

Q. Does portfolio diversity impact all hours equally?

A. No. Portfolio diversity is driven by interplay among the deviations by wind, solar, and load, so it is not a single number, but rather is dependent on the specific conditions. PacifiCorp's study incorporates two mechanisms to better account for these interactions. First, a portfolio diversity value is calculated specific to each hour of the day in each season. Second, rather than applying an equal percentage reduction to all hours, diversity benefits are assumed to be highest when stand-alone requirements are highest. For example, there is more opportunity for offsetting requirements when load, wind, and solar all have significant stand-alone requirements. With that in mind, diversity is applied as an exponent to the incremental requirement in excess of the EIM minimum requirement. The result of this calculation is a diversity benefit which is highest for large reserve requirements, and which approaches zero as the requirement approaches the EIM minimum, as illustrated in Table 2.

Table 2: Portfolio Diversity Exponent Example

			Incremental Requirement w/ Diversity (MW) By Diversity Exponent			Portfolio Diversity (%) By Diversity Exponent		
Stand-alone Reserve Req. (MW)	EIM Floor (MW)	Stand-alone Incremental Req. (MW)	d = c ^ 75%	e = c ^ 85%	f = c ^ 95%	g = 1 - (b + d)/a	h = 1 - (b + e)/a	i = 1 - (b + f)/a
a	b	c = a - b	75%	85%	95%	75%	85%	95%
200	200	0	0	0	0	0%	0%	0%
250	200	50	19	28	41	12%	9%	4%
300	200	100	32	50	79	23%	17%	7%
350	200	150	43	71	117	31%	23%	9%
400	200	200	53	90	153	37%	27%	12%
450	200	250	63	109	190	42%	31%	13%
500	200	300	72	128	226	46%	34%	15%

Q. How did the Company use this portfolio diversity technique to develop portfolio-specific regulation reserve requirements?

A. For a range of potential wind and solar capacity combinations, the hourly portfolio diversity exponents for each season were increased in a stepwise fashion until the risk of regulation reserve shortfalls during an interval is sufficiently low and the overall risk of regulation reserve shortfalls achieves the target of 0.5 hours per year. The resulting portfolio diversity is maximized for a combination of wind and solar as summarized in Table 3 and Table 4 for PacifiCorp East and PacifiCorp West, respectively.

Table 3: PacifiCorp East Diversity by Portfolio Composition

(% Reduction vs. Stand-alone Requirements)

East Wind Capacity

MW	%								
8,224	**548%**	17.2%	18.8%	20.6%					*Not enough interconnection*
7,184	**472%**	19.2%	21.5%	23.0%	25.5%	26.5%			*capacity in 2021 IRP*
6,144	**395%**	22.9%	24.1%	25.6%	27.9%	28.5%	29.0%		*to reach*
5,104	**319%**	26.0%	27.3%	29.2%	30.7%	30.7%	30.5%	29.5%	*these*
4,064	**242%**	30.4%	31.6%	32.9%	33.8%	32.7%	32.8%	32.8%	*levels*
3,024	**166%**	35.0%	36.2%	38.5%	37.1%	37.6%	36.2%	33.9%	31.9%
1,575	**100%**		48.0%	45.8%	43.1%	39.5%	35.8%	32.2%	29.4%
788	**50%**			46.4%	40.3%	36.4%	33.0%	30.0%	27.3%
	%	**50%**	**100%**	**166%**	**329%**	**493%**	**656%**	**820%**	**983%**
	MW	**428**	**855**	**1,462**	**2,502**	**3,542**	**4,582**	**5,622**	**6,662**

East Solar Capacity

$\boxed{}$ 2018-2019 Actual Wind and Solar Capacity

Table 4: PacifiCorp West Diversity by Portfolio Composition

(% Reduction vs. Stand-alone Requirements)

West Wind Capacity

MW	%								
4,389	**548%**	21.1%	22.4%	22.9%	*Not enough interconnection*				
3,669	**472%**	23.4%	24.8%	25.4%	29.0%	33.0%	*capacity in 2021 IRP*		
2,949	**395%**	26.2%	26.7%	27.6%	32.1%	34.8%	38.1%	*to reach*	
2,229	**319%**	29.6%	30.6%	31.4%	36.2%	39.5%	42.7%	42.7%	*these*
1,509	**242%**	33.8%	34.5%	36.3%	40.8%	45.2%	46.2%	43.9%	*levels*
789	**166%**	38.8%	41.6%	43.1%	47.6%	48.4%	47.7%	45.0%	44.3%
726	**100%**		$\boxed{42.4\%}$	42.9%	48.6%	49.3%	47.7%	46.2%	44.4%
363	**50%**			41.7%	47.1%	49.8%	47.4%	45.0%	43.2%
	%	**50%**	**100%**	**166%**	**329%**	**493%**	**656%**	**820%**	**983%**
	MW	**111**	**221**	**321**	**1,041**	**1,761**	**2,481**	**3,201**	**3,921**

West Solar Capacity

☐ 2018-2019 Actual Wind and Solar Capacity

Q. How does this translate to a portfolio-specific regulation reserve requirement?

A. Regulation reserve requirements are calculated specific to a portfolio's load, wind, and solar resources. The hourly regulation reserve requirement varies as a function of annual peak load as well as total wind and solar capacity. The regulation reserve requirement also varies based on the hourly load and hourly wind and solar generation values. Diversity exponents specific to the wind and solar capacity in each year are applied by hour and season, by interpolating among the scenarios illustrated in Tables 3 and 4. For example, the diversity exponent for hour five in the spring for a PACW study with 1,000 MW of wind and 1,000 MW of solar would reflect a weighting of diversity exponents in hour five in the spring from four scenarios. The highest weighting would apply to the 789 MW wind/1,041 MW solar scenario, and successively lower weightings would apply to 1,509 MW wind/1,041 MW solar, 789 MW wind/321 MW solar, and 1,509 MW wind/321 MW solar, with the total weighting for all four scenarios summing to 100 percent.

Q. Are there any other adjustments to the calculated requirement?

A. Yes. An adjustment is made to account for the ability of resources that are combined with storage to offset their own generation shortfalls beyond what is already captured by the model. For example, combined solar and storage resources can offset their own generation shortfalls, up to their interconnection limit. In actual operation, a reduction in solar generation would enable additional storage discharge. However, within PacifiCorp's current production cost modeling, there are no intra-hour variations in load or renewable resource output and thus no potential increase in storage discharge. Note that combined storage can only be discharged when there is a generation shortfall at the adjacent resource, so it cannot cover all shortfalls across the system. For example, many solar resources do not have co-located storage, and their errors would continue to need to be met with incremental reserves. Nonetheless, combined solar and storage can cover a portion of their own shortfalls, and that portion increases as more combined storage resources are added to the system. This adjustment reduces the hourly regulation reserve requirement that is entered in the model.

Q. How does the regulation reserve requirement calculation align with the 2023 TAM study period?

A. The regulation reserve requirement calculation relies on the hourly load, wind, and solar assumed in the 2023 TAM study period, along with the nameplate capacity of wind and solar resources. The resulting regulation reserve requirements for the PACE and PACW BAAs are thus specific to the 2023 TAM study period. For more details on the impact of regulation reserve requirements on the 2023 TAM, please refer to the testimony of Company witness Mr. Michael Wilding.

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. UE 400
Exhibit PAC/400
Witness: Judith M. Ridenour

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Direct Testimony of Judith M. Ridenour

March 2022

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II. PURPOSE OF TESTIMONY 1
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ATTACHED EXHIBITS

Exhibit PAC/401—Proposed TAM Rate Spread and Rates

Exhibit PAC/402—Proposed Tariff Schedule

Exhibit PAC/403—Estimated Effect of Proposed TAM Price Change

I. INTRODUCTION AND QUALIFICATIONS

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

A. My name is Judith M. Ridenour. My business address is 825 NE Multnomah Street, Suite 2000, Portland, Oregon 97232. My current position is Specialist, Pricing and Cost of Service, in the regulation department.

Q. Briefly describe your education and professional experience.

A. I have a Bachelor of Arts degree in Mathematics from Reed College. I joined the Company in the regulation department in October 2000. I assumed my present responsibilities in May 2001. In my current position, I am responsible for the preparation of rate design used in retail price filings and related analyses. Since 2001, with levels of increasing responsibility, I have analyzed and implemented rate design proposals throughout the Company's six-state service territory.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. I present PacifiCorp's proposed rate spread, rates, and revised tariff pages for the 2023 Transition Adjustment Mechanism (TAM) to recover the Oregon-allocated forecast net power costs (NPC) identified by Mr. Michael G. Wilding. I also provide a summary of the impact of the proposed rate change on customers' bills.

III. PROPOSED RATE SPREAD AND RATE DESIGN

Q. Please describe the Company's tariff rate schedule that collects NPC.

A. PacifiCorp collects NPC through Schedule 201, Net Power Costs, Cost-Based Supply Service. Collecting NPC through a separate rate schedule allows NPC to be more easily and accurately updated through TAM filings.

Q. What is the test period for this TAM?

A. In accordance with the TAM Guidelines adopted in Order 09-274,[1] the test period for this TAM is the test year for the concurrent general rate case, which is the forecast 12 months ending December 31, 2023.

Q. How did the Company allocate NPC to the rate schedule classes?

A. PacifiCorp allocated forecast NPC to the customer classes based on the generation allocation factors from the concurrently filed general rate case (2023 Rate Case). This methodology accurately allocates NPC to each customer class and ensures synchronization between the TAM and the 2023 Rate Case. The spread of the proposed NPC to the customer classes is shown in page one of Exhibit PAC/401.

Q. Did you prepare an exhibit showing the rate spread and present and proposed Schedule 201 rates and revenues?

A. Yes. Exhibit PAC/401 shows present and proposed Schedule 201 rates and revenues. As explained by Mr. Wilding, forecast NPC is subject to updates throughout this proceeding. Proposed Schedule 201 rates incorporate tariff changes proposed in the testimony of Mr. Robert M. Meredith in the 2023 Rate Case for seasonal residential rates.

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[1] *In the Matter of PacifiCorp, d/b/a Pacific Power, 2009 Transition Adjustment Mechanism Schedule 200, Cost-Based Supply Service,* Docket No. UE 199, Order No. 09-274 (July 16, 2009).

Q. Is the proposed Schedule 201 rate design consistent with the TAM Guidelines?

A. Yes. The proposed Schedule 201 rates are designed to collect revenues from rate schedules based on the proposed rate spread described above. Additionally, the rates in PacifiCorp's proposed Schedule 201 follow the proposed rate blocks and relationships between rate blocks as proposed in the concurrent general rate case.

Q. Are changes necessary in the 2023 TAM to Schedule 205 related to TAM Adjustment for Other Revenues?

A. No. PacifiCorp's Schedule 205, TAM Adjustment for Other Revenues, is used to collect or distribute the adjustment related to other revenues in a stand-alone TAM filing. As part of the Company's 2023 Rate Case, Schedule 205 rates are proposed to go to zero as the present adjustments will now be incorporated into base rates. The tariff will be kept in place for future use.

Q. Please describe Exhibit PAC/402.

A. Exhibit PAC/402 contains the proposed revised Schedule 201.

Q. Is the Company proposing changes to its transition adjustment tariff schedules at this time?

A. No. The Company will file changes to the transition adjustment tariffs—Schedules 294, 295, and 296—once the final TAM rates have been posted and are known. The Transition Adjustment rates will be established in November, just before the open enrollment window.

Q. Are there other tariff changes which will be made in the compliance filing in this docket?

A. Yes. The Company will file Schedule 293 to reflect any changes to the Company

Supply Service Access Charge and Schedule 220 to reflect updated market weightings based on the final TAM results in November.

IV. COMPARISON OF PRESENT AND PROPOSED CUSTOMER RATES

Q. What are the overall rate effects of the changes proposed in this filing?

A. The overall proposed effect is a rate increase of 5.6 percent, on a net basis. The rate change varies by customer type. Page one of Exhibit PAC/403 shows the estimated effect of PacifiCorp's proposed prices by delivery service schedule both excluding (base) and including (net) applicable adjustment schedules. The net rates in Columns 7 and 10 exclude effects of the Low Income Bill Payment Assistance Charge (Schedule 91), the Adjustment Associated with the Pacific Northwest Electric Power Planning and Conservation Act (Schedule 98), the Public Purpose Charge (Schedule 290), and the System Benefits Charge (Schedule 291).

Q. Did you prepare an exhibit that shows the impact on customer bills as a result of the proposed TAM rate change?

A. Yes. Exhibit PAC/403, beginning on page two, contains monthly billing comparisons for customers at different usage levels served on each of the major delivery service schedules. Each bill impact is shown in both dollars and percentages. These bill comparisons include the effects of all adjustment schedules including the Low Income Bill Payment Assistance Charge (Schedule 91), the Adjustment Associated with the Pacific Northwest Electric Power Planning and Conservation Act (Schedule 98), the Public Purpose Charge (Schedule 290), and the System Benefits Charge (Schedule 291).

Q. What is the estimated monthly impact to an average residential customer?

A. The estimated average monthly impact to the average residential customer using 900 kilowatt-hours per month is a bill increase of $7.16.

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. UE 400
Exhibit PAC/401
Witness: Judith M. Ridenour

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Judith M. Ridenour

Proposed TAM Rate Spread and Rates

March 2022

PACIFIC POWER
STATE OF OREGON
Functionalized Net Power Cost Revenue Requirement
Forecast 12 Months Ended December 31, 2023
Dollars in Thousands

			(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)
			Residential	**General Service**		**General Service**		**General Service**		**Large Power Service**			**Irrigation**	**Street Lgt.**
		Total		Sch 23		Sch 28		Sch 30		Sch 48T			Sch 41	Sch 15, 51
Line	Description		(sec)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(trn)		53, 54
1	Functionalized Generation Revenue Requirement from GRC	$744,404	$321,572	$60,971	$168	$104,538	$1,235	$61,602	$5,108	$28,200	$72,947	$73,647	$13,535	$881
2														
3	Net Power Cost Revenue Requirement	$358,510												
4	Net Power Cost Collection for Schedules not included in COS Study*	$568												
5	Net Power Cost for Schedules Included in COS Study	$357,941												
6														
7														
8	Generation Allocation Factors from GRC	100.00%	43.20%	8.19%	0.02%	14.04%	0.17%	8.28%	0.69%	3.79%	9.80%	9.89%	1.82%	0.12%
9														
10														
11	**Functionalized Net Power Cost Revenue Requirement- (Target)**	**$357,941**	**$154,626**	**$29,318**	**$81**	**$50,266**	**$594**	**$29,621**	**$2,456**	**$13,560**	**$35,076**	**$35,413**	**$6,508**	**$424**
12	Other Generation Revenue Requirement - (Target)	$386,462	$166,946	$31,654	$87	$54,271	$641	$31,981	$2,652	$14,640	$37,871	$38,234	$7,027	$457
13	Sum	$744,404	$321,572	$60,971	$168	$104,538	$1,235	$61,602	$5,108	$28,200	$72,947	$73,647	$13,535	$881

*Revenues by rate schedule as follow:

Schedule 47 Primary	$364
Schedule 47 Transmission	$294
Schedule 848 Transmission	$0
Employee Discount	($89)
Total not in study	$568

PACIFIC POWER
STATE OF OREGON
TAM Schedule 201 Present and Proposed Rates and Revenues

Forecast 12 Months Ended December 31, 2023

		Present Schedule 201		Proposed Schedule 201	
Rate Schedule	Forecast Energy	Rates	Revenues	Rates	Revenues
Schedule 4, Residential					
First Block kWh (0-1,000)	4,223,752,316	2.016 ¢	$85,150,847		
Second Block kWh (> 1,000)	1,410,104,163	2.705 ¢	$38,143,318		
Summer kWh	1,572,474,819			3.429 ¢	$53,920,162
Winter kWh	4,061,381,660			2.479 ¢	$100,681,651
	5,633,856,479		$123,294,165		$154,601,813
				Change	$31,307,648
Schedule 6 TOU Pilot					
Untiered, per kWh		2.184			
Summer, per kWh				*3.429 ¢*	
Winter, per kWh				*2.479 ¢*	
Employee Discount					
First Block kWh (0-1,000)	9,044,711	2.016 ¢	$182,341		
Second Block kWh (> 1,000)	3,984,798	2.705 ¢	$107,789		
Summer kWh	3,636,687			3.429 ¢	$124,702
Winter kWh	9,392,822			2.479 ¢	$232,848
	13,029,509		$290,130		$357,550
Discount			-$72,533		-$89,388
				Change	-$16,855
Schedule 23, Small General Service					
Secondary Voltage					
1st 3,000 kWh, per kWh	889,068,833	2.197 ¢	$19,532,842	2.739 ¢	$24,351,595
All additional kWh, per kWh	244,618,153	1.629 ¢	$3,984,830	2.031 ¢	$4,968,195
	1,133,686,986		$23,517,672		$29,319,790
				Change	$5,802,118
Primary Voltage					
1st 3,000 kWh, per kWh	1,804,482	2.130 ¢	$38,435	2.656 ¢	$47,927
All additional kWh, per kWh	1,519,255	1.580 ¢	$24,004	1.970 ¢	$29,929
	3,323,737		$62,439		$77,856
				Change	$15,417
Schedule 28, General Service 31-200kW					
Secondary Voltage					
All kWh, per kWh	1,968,466,445	2.087 ¢	$41,081,895	2.554 ¢	$50,274,633
	1,968,466,445		$41,081,895		$50,274,633
				Change	$9,192,738
Primary Voltage					
All kWh, per kWh	23,804,268	2.068 ¢	$492,272	2.494 ¢	$593,678
	23,804,268		$492,272		$593,678
				Change	$101,406
Schedule 29 TOU Pilot, untiered, per kWh		2.184		*2.673 ¢*	
Schedule 30, General Service 201-999kW					
Secondary Voltage					
All kWh, per kWh	1,183,141,965	2.036 ¢	$24,088,770	2.505 ¢	$29,637,706
	1,183,141,965		$24,088,770		$29,637,706
				Change	$5,548,936
Primary Voltage					
All kWh, per kWh	98,439,365	2.068 ¢	$2,035,726	2.495 ¢	$2,456,062
	98,439,365		$2,035,726		$2,456,062
				Change	$420,336
Schedule 41, Agricultural Pumping Service					
Secondary Voltage					
All kWh, per kWh	263,527,024	1.974 ¢	$5,202,023	2.469 ¢	$6,506,482
	263,527,024		$5,202,023		$6,506,482
				Change	$1,304,459
Primary Voltage					
All kWh, per kWh	38,046	1.943 ¢	$739	2.431 ¢	$925
	38,046		$739		$925
				Change	$186
Schedule 47, Large General Service, Partial Requirements 1,000kW and over					
Primary Voltage					
On-Peak, per on-peak kWh	6,254,381	2.374 ¢	$148,479	2.921 ¢	$182,690
Off-Peak, per off-peak kWh	8,717,189	1.686 ¢	$146,972	2.075 ¢	$180,882
	14,971,570		$295,451		$363,572
				Change	$68,121
Transmission Voltage					
On-Peak, per on-peak kWh	4,661,426	2.259 ¢	$105,302	2.829 ¢	$131,872
Off-Peak, per off-peak kWh	8,242,512	1.571 ¢	$129,490	1.968 ¢	$162,213
	12,903,938		$234,792		$294,085
				Change	$59,293

PACIFIC POWER
STATE OF OREGON
TAM Schedule 201 Present and Proposed Rates and Revenues

Forecast 12 Months Ended December 31, 2023

Rate Schedule	Forecast Energy	Present Schedule 201 Rates		Present Schedule 201 Revenues	Proposed Schedule 201 Rates		Proposed Schedule 201 Revenues
Schedule 48, Large General Service, 1,000kW and over							
Secondary Voltage							
On-Peak, per on-peak kWh	208,040,254	2.461	¢	$5,119,871	3.003	¢	$6,247,449
Off-Peak, per off-peak kWh	337,870,722	1.774	¢	$5,993,827	2.164	¢	$7,311,522
	545,910,976			$11,113,698			$13,558,971
					Change		$2,445,273
Primary Voltage							
On-Peak, per on-peak kWh	554,616,861	2.374	¢	$13,166,604	2.921	¢	$16,200,359
Off-Peak, per off-peak kWh	909,700,209	1.686	¢	$15,337,546	2.075	¢	$18,876,279
	1,464,317,070			$28,504,150			$35,076,638
					Change		$6,572,488
Transmission Voltage							
On-Peak, per on-peak kWh	581,207,821	2.259	¢	$13,129,485	2.829	¢	$16,442,369
Off-Peak, per off-peak kWh	964,027,967	1.571	¢	$15,144,879	1.968	¢	$18,972,070
	1,545,235,788			$28,274,364			$35,414,439
					Change		$7,140,075
Schedule 15, Outdoor Area Lighting Service							
Secondary Voltage							
All kWh, per kWh	8,259,954	*0.845*	¢	$69,726	*0.872*	¢	$72,015
	8,259,954			$69,726			$72,015
					Change		$2,290
Schedule 51, Street Lighting Service, Company-Owned System							
Secondary Voltage							
All kWh, per kWh	23,892,579	*0.987*	¢	$235,901	*1.017*	¢	$242,899
	23,892,579			$235,901			$242,899
					Change		$6,998
Schedule 53, Street Lighting Service, Consumer-Owned System							
Secondary Voltage							
All kWh, per kWh	11,451,780	0.830	¢	$95,050	0.857	¢	$98,142
	11,451,780			$95,050			$98,142
					Change		$3,092
Schedule 54, Recreational Field Lighting							
Secondary Voltage							
All kWh, per kWh	1,141,242	0.830	¢	$9,472	0.857	¢	$9,780
	1,141,242			$9,472			$9,780
					Change		$308
Total before Employee Discount				**$288,608,305**			**$358,599,486**
Employee Discount				-$72,533			-$89,388
TOTAL	**13,936,369,212**			**$288,535,773**			**$358,510,099**
					Change		**$69,974,326**
Schedule 47 Unscheduled kWh	1,233,140						
Total Forecast kWH	13,937,602,352						

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Judith M. Ridenour

Proposed Tariff Schedule

March 2022

Available

In all territory served by the Company in the State of Oregon.

Applicable

To Residential Consumers and Nonresidential Consumers who have elected to take Cost-Based Supply Service under this schedule or under Schedules 210, 211, 212, 213 or 247. This service may be taken only in conjunction with the applicable Delivery Service Schedule. Also applicable to Nonresidential Consumers who, based on the announcement date defined in OAR 860-038-275, do not elect to receive standard offer service under Schedule 220 or direct access service under the applicable tariff. In addition, applicable to some Large Nonresidential Consumers on Schedule 400 whose special contracts require prices under the Company's previously applicable Schedule 48T. For Consumers on Schedule 400 who were served on previously applicable Schedule 48T prices under their special contract, this service, in conjunction with Delivery Service Schedule 48, supersedes previous Schedule 48T.

Nonresidential Consumers who had chosen either service under Schedule 220 or who chose to receive direct access service under the applicable tariff may qualify to return to Cost-Based Supply Service under this Schedule after meeting the Returning Service Requirements and making a Returning Service Payment as specified in this Schedule.

Monthly Billing

The Monthly Billing shall be the Energy Charge, as specified below by Delivery Service Schedule.

Delivery Service Schedule No.			**Delivery Voltage**			
			Secondary	**Primary**	**Transmission**	(D)
4	Per Summer kWh		3.429¢			(N)
	Per Winter kWh		2.479¢			(N)
						(D)
5	Per Summer kWh		3.429¢			(N)
	Per Winter kWh		2.479¢			(N)
						(D)
6	Per Summer kWh		3.429¢			(N)
	Per Winter kWh		2.479¢			(N)
	plus	per On-Peak kWh	14.270¢			
	plus	per Off-Peak kWh (credit)	-3.790¢			

For Schedules 4, 5 and 6, Summer is defined as months of June through September. (N)
Winter is defined as the months of October through May. Seasonal kilowatt-hours shall (N)
be prorated to the nearest whole kilowatt-hour based upon the number of whole days in (N)
the billing period falling within each season. For Schedule 6, On-Peak hours are from 5 (N)
p.m. to 9 p.m., all days. Off-Peak hours are all remaining hours

23	First 3,000 kWh, per kWh	2.739¢	2.656¢		(I)
	All additional kWh, per kWh	2.031¢	1.970¢		(I)
28	All kWh, per kWh	2.554¢	2.494¢		(I)

(continued)

Monthly Billing (continued)

Delivery Service Schedule No.		Delivery Voltage Secondary	Primary	Transmission	
29	All kWh, per kWh	2.673¢	2.673¢		(I)
	Plus per Off-Peak kWh (credit)	-0.739¢	-0.739¢		

For Schedule 29, Summer On-Peak hours are from 4 p.m. to 8 p.m. Monday through Friday excluding holidays in the Summer months of April through October. Non-Summer On-Peak hours are from 6 a.m. to 10 a.m. and 5 p.m. to 8 p.m. Monday through Friday excluding holidays in the Non-Summer months of November through March. Off-Peak hours are all remaining hours.

		Secondary	Primary	Transmission	
30	All kWh, per kWh	2.505¢	2.495¢		(I)
41	All kWh, per kWh	2.469¢	2.431¢		(I)
	Optional TOU Adders				
	Plus per On-Peak kWh	4.989¢	4.989¢		
	Plus per Off-Peak kWh (credit)	-0.992¢	-0.992¢		

Schedule 41 Consumers may choose to participate in one of two Time-of-Use (TOU) rate options, Option A and Option B which provide time-varying rates in the Summer months of July, August and September. Consumers may choose to participate in Option A with On-Peak hours from 2 p.m. to 6 p.m. all days in Summer or Option B with On-Peak hours from 6 p.m. to 10 p.m. all days in Summer. Off-peak hours for each Option are all other Summer hours which are not On-Peak. All other months have no time-of-use periods or rate adders.

		Secondary	Primary	Transmission	
47/48	Per kWh On-Peak	3.003¢	2.921¢	2.829¢	(I)
	Per kWh, Off-Peak	2.164¢	2.075¢	1.968¢	(I)

For Schedule 47 and Schedule 48, Summer On-Peak hours are from 1 p.m. to 10 p.m. all days in the Summer months of June through September. Non-Summer On-Peak hours are from 6 a.m. to 9 a.m. and 4 p.m. to 10 p.m. in the Non-Summer months of October through May. Off-Peak hours are all remaining hours.

15	Type of Lamp	LED Equivalent Lumens	Monthly kWh	Rate per Lamp	
	Level 1	0-5,000	19	$0.65	(I)
	Level 2	5,001-12,000	34	$1.16	(I)
	Level 3	12,001+	57	$1.94	(I)

(continued)

Monthly Billing (continued)

Delivery Service Schedule No.

	Type of Lamp	LED Equivalent Lumens	Monthly kWh	Rate per Lamp	
51	Level 1	0-3,500	8	$0.24	(I)
	Level 2	3,501-5,500	15	$0.43	
	Level 3	5,501-8,000	25	$0.72	
	Level 4	8,001-12,000	34	$0.99	
	Level 5	12,001-15,500	44	$1.28	
	Level 6	15,501+	57	$1.66	(I)

	Types of Luminaire	Nominal rating	Watts	Monthly kWh	Rate Per Luminaire	
53	High Pressure Sodium	5,800	70	31	$0.27	(I)
	High Pressure Sodium	9,500	100	44	$0.38	
	High Pressure Sodium	16,000	150	64	$0.55	
	High Pressure Sodium	22,000	200	85	$0.73	
	High Pressure Sodium	27,500	250	115	$0.99	
	High Pressure Sodium	50,000	400	176	$1.51	
	Metal Halide	9,000	100	39	$0.33	
	Metal Halide	12,000	175	68	$0.58	
	Metal Halide	19,500	250	94	$0.81	
	Metal Halide	32,000	400	149	$1.28	
	Metal Halide	107,800	1,000	354	$3.03	
	Non-Listed Luminaire, per kWh				0.857¢	

54 Per kWh 0.857¢ (I)

(continued)

Docket No. UE 400
Exhibit PAC/403
Witness: Judith M. Ridenour

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Judith M. Ridenour

Estimated Effect of Proposed TAM Price Change

March 2022

TAM Price Change

PACIFIC POWER
ESTIMATED EFFECT OF PROPOSED PRICE CHANGE
ON REVENUES FROM ELECTRIC SALES TO ULTIMATE CONSUMERS
DISTRIBUTED BY RATE SCHEDULES IN OREGON
FORECAST 12 MONTHS ENDED DECEMBER 31, 2023

						Present Revenues ($000)			Proposed Revenues ($000)			Change				
												Base Rates		Net Rates		
Line No.	Description	Sch No.	Sch No.	No. of Cust	MWh	Base Rates	Adders[1]	Net Rates	Base Rates	Adders[1]	Net Rates	($000)	%[2]	($000)	%[2]	Line No.
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	
								(6) + (7)			(9) + (10)	(9) - (6)	(12)/(6)	(11) - (8)	(14)/(8)	
	Residential															
1	Residential	4	4	535,059	5,633,856	$597,063	$9,738	$606,801	$628,371	$9,738	$638,109	$31,308	5.2%	$31,308	5.2%	1
2	**Total Residential**			535,059	5,633,856	$597,063	$9,738	$606,801	$628,371	$9,738	$638,109	$31,308	5.2%	$31,308	5.2%	2
	Commercial & Industrial															
3	Gen. Svc. < 31 kW	23	23	84,329	1,137,011	$124,438	$1,015	$125,453	$130,256	$1,015	$131,271	$5,818	4.7%	$5,818	4.6%	3
4	Gen. Svc. 31 - 200 kW	28	28	10,462	1,992,271	$163,732	$9,197	$172,929	$173,026	$9,197	$182,223	$9,294	5.7%	$9,294	5.4%	4
5	Gen. Svc. 201 - 999 kW	30	30	797	1,281,581	$94,197	$4,696	$98,893	$100,166	$4,696	$104,862	$5,969	6.3%	$5,969	6.0%	5
6	Large General Service >= 1,000 kW	48	48	190	3,555,464	$224,400	($15,394)	$209,007	$240,558	($15,394)	$225,164	$16,158	7.1%	$16,158	7.7%	6
7	Partial Req. Svc. >= 1,000 kW	47	47	6	29,109	$3,974	($120)	$3,854	$4,101	($120)	$3,981	$127	7.1%	$127	7.7%	7
8	Dist. Only Lg Gen Svc >= 1,000 kW	848	848	1	0	$1,805	$10	$1,815	$1,805	$10	$1,815	$0	0.0%	$0	0.0%	8
9	Agricultural Pumping Service	41	41	7,997	263,565	$29,194	($3,645)	$25,549	$30,498	($3,645)	$26,854	$1,305	4.5%	$1,305	5.1%	9
10	**Total Commercial & Industrial**			103,782	8,259,000	$641,740	($4,241)	$637,499	$680,411	($4,241)	$676,170	$38,671	6.0%	$38,671	6.1%	10
	Lighting															
11	Outdoor Area Lighting Service	15	15	5,809	8,260	$915	$74	$989	$917	$74	$992	$2	0.3%	$2	0.2%	11
12	Street Lighting Service Comp. Owned	51	51	1,108	23,893	$3,498	$387	$3,885	$3,505	$387	$3,892	$7	0.2%	$7	0.2%	12
13	Street Lighting Service Cust. Owned	53	53	314	11,452	$657	$210	$867	$660	$210	$870	$3	0.5%	$3	0.4%	13
14	Recreational Field Lighting	54	54	102	1,141	$82	$27	$108	$82	$27	$109	$0	0.4%	$0	0.3%	14
15	**Total Public Street Lighting**			7,333	44,746	$5,151	$698	$5,849	$5,164	$698	$5,862	$13	0.3%	$13	0.2%	15
16	**Total Sales to Ultimate Consumers**			646,174	13,937,602	$1,243,954	$6,196	$1,250,150	$1,313,945	$6,196	$1,320,141	$69,991	5.6%	$69,991	5.6%	16
17	Employee Discount			*966*	*13,030*	($341)	($6)	($346)	($357)	($6)	($363)	($17)		($17)		17
18	AGA Revenue					$3,521		$3,521	$3,521		$3,521	$0		$0		18
19	COOC Amortization					$1,767		$1,767	$1,767		$1,767	$0		$0		19
20	**Total Sales with AGA**			646,174	13,937,602	$1,248,901	$6,190	$1,255,091	$1,318,875	$6,190	$1,325,065	$69,974	5.6%	$69,974	5.6%	20

[1] Excludes effects of the Low Income Bill Payment Assistance Charge (Sch. 91), BPA Credit (Sch. 98), Public Purpose Charge (Sch. 290) and System Benefits Charge (Sch. 291).

[2] Percentages shown for Schedules 48 and 47 reflect the combined rate change for both schedules

Pacific Power
TAM Monthly Billing Comparison
Delivery Service Schedule 4 + Cost-Based Supply Service
Residential Service - Single Family

	Monthly Billing*			Percent
kWh	Present Price	Proposed Price	Difference	Difference
100	$19.75	$20.55	$0.80	4.05%
200	$28.77	$30.37	$1.60	5.56%
300	$37.78	$40.17	$2.39	6.33%
400	$46.80	$49.99	$3.19	6.82%
500	$55.82	$59.80	$3.98	7.13%
600	$64.84	$69.62	$4.78	7.37%
700	$73.86	$79.43	$5.57	7.54%
800	$82.87	$89.24	$6.37	7.69%
900	**$91.89**	**$99.05**	**$7.16**	**7.79%**
1,000	$100.91	$108.87	$7.96	7.89%
1,100	$112.06	$120.11	$8.05	7.18%
1,200	$123.20	$131.34	$8.14	6.61%
1,300	$134.36	$142.59	$8.23	6.13%
1,400	$145.50	$153.83	$8.33	5.73%
1,500	$156.65	$165.06	$8.41	5.37%
1,600	$167.79	$176.30	$8.51	5.07%
2,000	$212.38	$221.26	$8.88	4.18%
3,000	$323.85	$333.65	$9.80	3.03%
4,000	$435.31	$446.05	$10.74	2.47%
5,000	$546.78	$558.44	$11.66	2.13%

* Net rate including Schedules 91, 98, 290 and 291.

Note: Assumed average billing cycle length of 30.42 days.

Pacific Power
TAM Monthly Billing Comparison
Delivery Service Schedule 4 + Cost-Based Supply Service
Residential Service - Multi-Family

	Monthly Billing*			Percent
kWh	Present Price	Proposed Price	Difference	Difference
100	$18.22	$19.02	$0.80	4.39%
200	$27.24	$28.83	$1.59	5.84%
300	$36.25	$38.64	$2.39	6.59%
400	$45.27	$48.46	$3.19	7.05%
500	$54.29	$58.27	$3.98	7.33%
600	$63.31	$68.09	$4.78	7.55%
700	$72.33	$77.90	$5.57	7.70%
800	$81.34	$87.71	$6.37	7.83%
900	$90.36	$97.52	$7.16	7.92%
1,000	$99.38	$107.34	$7.96	8.01%
1,100	$110.53	$118.57	$8.04	7.27%
1,200	$121.67	$129.81	$8.14	6.69%
1,300	$132.83	$141.06	$8.23	6.20%
1,400	$143.97	$152.30	$8.33	5.79%
1,500	$155.11	$163.53	$8.42	5.43%
1,600	$166.26	$174.77	$8.51	5.12%
2,000	$210.85	$219.73	$8.88	4.21%
3,000	$322.32	$332.12	$9.80	3.04%
4,000	$433.78	$444.52	$10.74	2.48%
5,000	$545.25	$556.91	$11.66	2.14%

* Net rate including Schedules 91, 98, 290 and 291.

Note: Assumed average billing cycle length of 30.42 days.

Pacific Power
TAM Monthly Billing Comparison
Delivery Service Schedule 23 + Cost-Based Supply Service
General Service - Secondary Delivery Voltage

		Monthly Billing*				Percent	
kW		Present Price		Proposed Price		Difference	
Load Size	kWh	Single Phase	Three Phase	Single Phase	Three Phase	Single Phase	Three Phase
5	500	$68	$77	$71	$79	4.06%	3.61%
	750	$93	$102	$97	$106	4.46%	4.08%
	1,000	$118	$127	$124	$133	4.68%	4.36%
	1,500	$169	$177	$177	$186	4.93%	4.68%
10	1,000	$118	$127	$124	$133	4.68%	4.36%
	2,000	$219	$228	$230	$239	5.05%	4.86%
	3,000	$319	$328	$336	$345	5.20%	5.06%
	4,000	$407	$415	$427	$436	5.09%	4.99%
20	4,000	$437	$446	$458	$467	4.73%	4.64%
	6,000	$612	$620	$641	$649	4.73%	4.66%
	8,000	$786	$795	$823	$832	4.72%	4.67%
	10,000	$960	$969	$1,006	$1,014	4.72%	4.68%
30	9,000	$935	$943	$976	$985	4.41%	4.37%
	12,000	$1,196	$1,205	$1,250	$1,258	4.47%	4.44%
	15,000	$1,458	$1,466	$1,523	$1,532	4.52%	4.49%
	18,000	$1,719	$1,728	$1,797	$1,806	4.54%	4.52%

* Net rate including Schedules 91, 290 and 291.

Pacific Power
TAM Monthly Billing Comparison
Delivery Service Schedule 23 + Cost-Based Supply Service
General Service - Primary Delivery Voltage

kW		Monthly Billing*				Percent	
		Present Price		Proposed Price		Difference	
Load Size	kWh	Single Phase	Three Phase	Single Phase	Three Phase	Single Phase	Three Phase
5	500	$67	$76	$70	$79	3.99%	3.53%
	750	$92	$101	$96	$105	4.39%	4.00%
	1,000	$116	$125	$122	$131	4.61%	4.29%
	1,500	$166	$175	$174	$183	4.85%	4.62%
10	1,000	$116	$125	$122	$131	4.61%	4.29%
	2,000	$215	$224	$226	$235	4.99%	4.79%
	3,000	$314	$323	$330	$339	5.13%	4.99%
	4,000	$400	$408	$420	$429	5.02%	4.92%
20	4,000	$430	$439	$450	$459	4.67%	4.57%
	6,000	$602	$610	$630	$638	4.66%	4.59%
	8,000	$773	$782	$809	$818	4.66%	4.61%
	10,000	$944	$953	$988	$997	4.66%	4.61%
30	9,000	$920	$928	$960	$968	4.35%	4.31%
	12,000	$1,177	$1,185	$1,229	$1,237	4.41%	4.38%
	15,000	$1,434	$1,443	$1,498	$1,506	4.45%	4.43%
	18,000	$1,691	$1,700	$1,767	$1,775	4.48%	4.46%

* Net rate including Schedules 91, 290 and 291.

Pacific Power
TAM Monthly Billing Comparison
Delivery Service Schedule 28 + Cost-Based Supply Service
Large General Service - Secondary Delivery Voltage

kW Load Size	kWh	Monthly Billing* Present Price	Monthly Billing* Proposed Price	Percent Difference
15	3,000	$328	$343	4.36%
	4,500	$426	$447	5.04%
	7,500	$621	$657	5.76%
31	6,200	$658	$687	4.49%
	9,300	$859	$904	5.16%
	15,500	$1,262	$1,336	5.85%
40	8,000	$843	$881	4.52%
	12,000	$1,103	$1,160	5.18%
	20,000	$1,623	$1,719	5.87%
60	12,000	$1,256	$1,313	4.55%
	18,000	$1,646	$1,732	5.21%
	30,000	$2,426	$2,569	5.89%
80	16,000	$1,662	$1,739	4.59%
	24,000	$2,183	$2,297	5.24%
	40,000	$3,223	$3,414	5.91%
100	20,000	$2,069	$2,164	4.61%
	30,000	$2,719	$2,862	5.26%
	50,000	$4,020	$4,258	5.93%
200	40,000	$4,071	$4,261	4.68%
	60,000	$5,371	$5,657	5.32%
	100,000	$7,972	$8,449	5.98%

* Net rate including Schedules 91, 290 and 291.

Pacific Power
TAM Monthly Billing Comparison
Delivery Service Schedule 28 + Cost-Based Supply Service
Large General Service - Primary Delivery Voltage

kW Load Size	kWh	Monthly Billing* Present Price	Proposed Price	Percent Difference
15	4,500	$429	$449	4.56%
	6,000	$521	$547	5.01%
	7,500	$612	$645	5.33%
31	9,300	$860	$900	4.70%
	12,400	$1,049	$1,103	5.14%
	15,500	$1,238	$1,305	5.44%
40	12,000	$1,102	$1,154	4.73%
	16,000	$1,346	$1,416	5.17%
	20,000	$1,590	$1,677	5.47%
60	18,000	$1,643	$1,722	4.76%
	24,000	$2,009	$2,114	5.19%
	30,000	$2,375	$2,506	5.49%
80	24,000	$2,176	$2,281	4.79%
	32,000	$2,664	$2,804	5.22%
	40,000	$3,152	$3,326	5.52%
100	30,000	$2,710	$2,840	4.81%
	40,000	$3,320	$3,493	5.24%
	50,000	$3,930	$4,147	5.53%
200	60,000	$5,342	$5,602	4.88%
	80,000	$6,562	$6,909	5.30%
	100,000	$7,782	$8,216	5.59%

* Net rate including Schedules 91, 290 and 291.

Pacific Power
TAM Monthly Billing Comparison
Delivery Service Schedule 30 + Cost-Based Supply Service
Large General Service - Secondary Delivery Voltage

kW Load Size	kWh	Monthly Billing* Present Price	Monthly Billing* Proposed Price	Percent Difference
100	20,000	$2,505	$2,601	3.82%
	30,000	$2,990	$3,133	4.80%
	50,000	$3,960	$4,199	6.04%
200	40,000	$4,505	$4,697	4.25%
	60,000	$5,475	$5,763	5.24%
	100,000	$7,415	$7,894	6.45%
300	60,000	$6,685	$6,972	4.30%
	90,000	$8,140	$8,571	5.29%
	150,000	$11,050	$11,768	6.50%
400	80,000	$8,737	$9,120	4.38%
	120,000	$10,677	$11,252	5.38%
	200,000	$14,557	$15,515	6.58%
500	100,000	$10,825	$11,304	4.42%
	150,000	$13,250	$13,968	5.42%
	250,000	$18,100	$19,296	6.61%
600	120,000	$12,912	$13,487	4.45%
	180,000	$15,822	$16,684	5.44%
	300,000	$21,642	$23,078	6.63%
800	160,000	$17,087	$17,853	4.48%
	240,000	$20,967	$22,116	5.48%
	400,000	$28,727	$30,642	6.66%
1000	200,000	$21,262	$22,219	4.50%
	300,000	$26,112	$27,548	5.50%
	500,000	$35,792	$38,185	6.69%

* Net rate including Schedules 91, 290 and 291.

Pacific Power
TAM Monthly Billing Comparison
Delivery Service Schedule 30 + Cost-Based Supply Service
Large General Service - Primary Delivery Voltage

kW Load Size	kWh	Monthly Billing* Present Price	Monthly Billing* Proposed Price	Percent Difference
100	30,000	$2,979	$3,110	4.39%
	40,000	$3,465	$3,640	5.03%
	50,000	$3,952	$4,170	5.51%
200	60,000	$5,467	$5,728	4.78%
	80,000	$6,440	$6,788	5.41%
	100,000	$7,412	$7,848	5.88%
300	90,000	$8,123	$8,515	4.83%
	120,000	$9,582	$10,105	5.46%
	150,000	$11,042	$11,695	5.92%
400	120,000	$10,679	$11,202	4.90%
	160,000	$12,625	$13,322	5.52%
	200,000	$14,571	$15,442	5.98%
500	150,000	$13,249	$13,903	4.93%
	200,000	$15,681	$16,553	5.56%
	250,000	$18,113	$19,203	6.01%
600	180,000	$15,818	$16,603	4.96%
	240,000	$18,737	$19,783	5.58%
	300,000	$21,656	$22,963	6.04%
800	240,000	$20,958	$22,003	4.99%
	320,000	$24,849	$26,243	5.61%
	400,000	$28,740	$30,483	6.06%
1000	300,000	$26,097	$27,404	5.01%
	400,000	$30,961	$32,704	5.63%
	500,000	$35,805	$37,984	6.08%

* Net rate including Schedules 91, 290 and 291.

Pacific Power
TAM Monthly Billing Comparison
Delivery Service Schedule 41 + Cost-Based Supply Service
Agricultural Pumping - Secondary Delivery Voltage

		Present Price*		Proposed Price*		Percent Difference	
kW Load Size	kWh	April - November Monthly Bill	Annual Load Size Charge	April - November Monthly Bill	Annual Load Size Charge	April - November Monthly Bill	Annual Load Size Charge
Single Phase							
10	2,000	$161	$175	$171	$175	6.29%	0.00%
	3,000	$241	$175	$256	$175	6.29%	0.00%
	5,000	$402	$175	$427	$175	6.29%	0.00%
Three Phase							
20	4,000	$321	$349	$342	$349	6.29%	0.00%
	6,000	$482	$349	$512	$349	6.29%	0.00%
	10,000	$803	$349	$854	$349	6.29%	0.00%
100	20,000	$1,607	$1,561	$1,708	$1,561	6.29%	0.00%
	30,000	$2,410	$1,561	$2,561	$1,561	6.29%	0.00%
	50,000	$4,016	$1,561	$4,269	$1,561	6.29%	0.00%
300	60,000	$4,820	$3,929	$5,123	$3,929	6.29%	0.00%
	90,000	$7,229	$3,929	$7,684	$3,929	6.29%	0.00%
	150,000	$12,049	$3,929	$12,807	$3,929	6.29%	0.00%

* Net rate including Schedules 91, 98, 290 and 291.

Pacific Power
TAM Monthly Billing Comparison
Delivery Service Schedule 41 + Cost-Based Supply Service
Agricultural Pumping - Primary Delivery Voltage

		Present Price*		Proposed Price*		Percent Difference	
kW Load Size	kWh	April - November Monthly Bill	Annual Load Size Charge	April - November Monthly Bill	Annual Load Size Charge	April - November Monthly Bill	Annual Load Size Charge
Single Phase							
10	3,000	$236	$172	$251	$172	6.32%	0.00%
	4,000	$315	$172	$335	$172	6.32%	0.00%
	5,000	$394	$172	$419	$172	6.32%	0.00%
Three Phase							
20	6,000	$473	$345	$503	$345	6.32%	0.00%
	8,000	$630	$345	$670	$345	6.32%	0.00%
	10,000	$788	$345	$838	$345	6.32%	0.00%
100	30,000	$2,364	$1,541	$2,513	$1,541	6.32%	0.00%
	40,000	$3,152	$1,541	$3,351	$1,541	6.32%	0.00%
	50,000	$3,940	$1,541	$4,189	$1,541	6.32%	0.00%
300	90,000	$7,092	$3,868	$7,540	$3,868	6.32%	0.00%
	120,000	$9,457	$3,868	$10,054	$3,868	6.32%	0.00%
	150,000	$11,821	$3,868	$12,567	$3,868	6.32%	0.00%

* Net rate including Schedules 91, 98, 290 and 291.

Pacific Power
TAM Monthly Billing Comparison
Delivery Service Schedule 48 + Cost-Based Supply Service
Large General Service - Secondary Delivery Voltage
1,000 kW and Over

kW Load Size	kWh	Monthly Billing Present Price	Monthly Billing Proposed Price	Percent Difference
1,000	300,000	$25,940	$27,312	5.29%
	500,000	$35,159	$37,445	6.50%
	700,000	$44,190	$47,389	7.24%
2,000	600,000	$51,165	$53,908	5.36%
	1,000,000	$67,127	$71,788	6.94%
	1,400,000	$84,164	$90,689	7.75%
6,000	1,800,000	$137,264	$145,653	6.11%
	3,000,000	$188,374	$202,356	7.42%
	4,200,000	$239,484	$259,059	8.17%
12,000	3,600,000	$272,363	$289,141	6.16%
	6,000,000	$374,583	$402,547	7.47%
	8,400,000	$476,804	$515,953	8.21%

Notes:	Present	Proposed
On-Peak kWh	38.11%	38.11%
Off-Peak kWh	61.89%	61.89%

* Net rate including Schedules 91, 290 and 291. Restricted Sch 291 applied to levels over 730,000 kWh.

Pacific Power
TAM Monthly Billing Comparison
Delivery Service Schedule 48 + Cost-Based Supply Service
Large General Service - Primary Delivery Voltage
1,000 kW and Over

kW Load Size	kWh	Monthly Billing: Present Price	Monthly Billing: Proposed Price	Percent Difference
1,000	300,000	$24,192	$25,566	5.68%
	500,000	$32,897	$35,188	6.96%
	700,000	$41,415	$44,622	7.74%
2,000	600,000	$47,698	$50,446	5.76%
	1,000,000	$62,546	$67,217	7.47%
	1,400,000	$78,538	$85,076	8.32%
6,000	1,800,000	$135,690	$144,096	6.20%
	3,000,000	$183,663	$197,674	7.63%
	4,200,000	$231,637	$251,251	8.47%
12,000	3,600,000	$269,330	$286,142	6.24%
	6,000,000	$365,277	$393,297	7.67%
	8,400,000	$461,223	$500,452	8.51%

Notes:	Present	Proposed
On-Peak kWh	37.88%	37.88%
Off-Peak kWh	62.12%	62.12%

* Net rate including Schedules 91, 290 and 291. Restricted Sch 291 applied to levels over 730,000 kWh.

Exhibit PAC/403
Ridenour/13

Pacific Power
TAM Monthly Billing Comparison
Delivery Service Schedule 48 + Cost-Based Supply Service
Large General Service - Transmission Delivery Voltage
1,000 kW and Over

kW Load Size	kWh	Monthly Billing Present Price	Monthly Billing Proposed Price	Percent Difference
1,000	500,000	$31,074	$33,431	7.59%
	700,000	$39,017	$42,318	8.46%
2,000	1,000,000	$58,661	$63,469	8.20%
	1,400,000	$73,480	$80,211	9.16%
6,000	3,000,000	$173,411	$187,834	8.32%
	4,200,000	$217,870	$238,063	9.27%
12,000	6,000,000	$344,428	$373,275	8.38%
	8,400,000	$433,347	$473,732	9.32%

Notes:	Present	Proposed
On-Peak kWh	37.61%	37.61%
Off-Peak kWh	62.39%	62.39%

* Net rate including Schedules 91, 290 and 291. Restricted Sch 291 applied to levels over 730,000 kWh.