PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
Portland, Oregon 97232

April 1, 2021

VIA ELECTRONIC FILING

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

Attn: Filing Center

Re: Advice No. 21-008/UE 390—PacifiCorp's 2022 Transition Adjustment Mechanism

In compliance with ORS 757.205, OAR 860-022-0025, and OAR 860-022-0030, PacifiCorp d/b/a Pacific Power 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, 2022.

A. Description of Filing

The purpose of the Transition Adjustment Mechanism (TAM) is to update net power costs for 2022 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. Ridenour's Exhibit PAC/302. This tariff filing is supported by testimony and exhibits from the following witnesses:

- David G. Webb, Manager, Net Power Costs
- Dana M. Ralston, Senior Vice President, Thermal Generation and Mining
- Judith M. Ridenour, Specialist, Cost of Service and Pricing

B. Tariff Sheets

Fifteenth Revision of Sheet No. 201-1	Schedule 201	Net Power Costs – Cost-Based Supply Service
Fifteenth Revision of Sheet No. 201-2	Schedule 201	Net Power Costs – Cost-Based Supply Service
Fifteenth 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 628,000 customers, and would result in an overall annual rate increase of approximately $1.2 million or 0.1 percent. Residential customers using 900 kilowatt-hours per month would see a monthly bill increase of $0.08 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 375. Confidential material in support of the filing has been provided to parties under Order No. 16-128.

Sincerely,

Etta Lockey
Vice President, Regulation and Customer and Community Solutions.

Enclosures

cc: UE 375 Service List

CERTIFICATE OF SERVICE

I certify that I delivered a true and correct copy of PacifiCorp's **Advice No. 21-008/UE 390—PacifiCorp's 2022 Transition Adjustment Mechanism** on the parties listed below via electronic mail and/or or overnight delivery in compliance with OAR 860-001-0180.

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Dated this 1st day of April, 2021.

Katie Savarin

Katie Savarin
Coordinator, Regulatory Operations

REDACTED
Docket No. UE 390
Exhibit PAC/100
Witness: David G. Webb

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED
Direct Testimony of David G. Webb

April 2021

DIRECT TESTIMONY OF DAVID G. WEBB

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ATTACHED EXHIBITS

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

Q. Please describe your education and professional experience.

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

Q. Have you testified in previous regulatory proceedings?

A. Yes. I have previously provided testimony to the Public Utility Commission of Oregon (Commission) as well as commissions in California, Oregon, 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 2022 Transition Adjustment Mechanism (TAM) net power costs (NPC). Specifically, my testimony:

- Summarizes the content of the filing;
- Defines NPC and describes the NPC change in the 2022 TAM compared to the final NPC in docket UE 375, the 2021 TAM;
- Describes modeling changes the Company is proposing in this TAM filing;

- Describes the major cost drivers in the 2022 TAM;
- 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;
- Provides information requested by the Commission on PacifiCorp's Huntington facility;
- 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 2022 TAM.

A. Two additional Company witnesses provide testimony supporting the Company's filing. Mr. Dana M. Ralston, Senior Vice President, Thermal Generation and Mining, provides testimony supporting the coal fuel costs and the prudence of the new coal agreements included in the 2022 TAM. 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 2022 TAM FILING

Q. Please provide background on PacifiCorp's 2022 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 2022 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.

As shown in Exhibit PAC/101, the 2022 TAM results in an increase to Oregon rates of approximately $1.2 million, which includes a decrease to Oregon-allocated NPC of approximately $14.0 million and an increase in PTCs (decrease to rates) of approximately $9.5 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 2022 TAM results in an overall average rate increase of approximately 0.1 percent.

Q. What is the total-company NPC in the TAM for calendar year 2022?

A. The forecasted normalized total-company NPC for calendar year 2022 is approximately $1.445 billion.[1] This is approximately $45.1 million higher than the forecast NPC of approximately $1.400 billion in the 2021 TAM. Details of total-company NPC for 2022 are provided in Exhibit PAC/102.

Q. Does the proposed rate increase for the 2022 TAM reflect changes in Oregon load since the 2021 TAM?

A. Yes. The 2022 load forecast used in the Company's calculation of NPC reflects an increase in Oregon load compared to the 2021 forecast loads in the 2021 TAM. Due to the increase in Oregon load, the Company anticipates it will need to collect approximately $3.3 million more than what was approved in the 2021 TAM.

Q. How are Other Revenues for certain items related to NPC treated in the 2022 TAM?

A. As part of the Company's 2021 General Rate Case, docket UE 374, Schedule 205 rates were adjusted to zero as the previous adjustments were incorporated into base

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

rates. There is no adjustment related to Other Revenues in this filing.

Q. Please explain how the EIM inter-regional and GHG benefits are treated in the 2022 TAM.

A. PacifiCorp's initial filing includes a forecast of both the inter-regional benefits and greenhouse gas (GHG) benefits from participation in the EIM. The expected incremental inter-regional EIM benefits relative to the optimized NPC modeled by the Generation and Regulation Initiative Decision Tools (GRID) model are reflected as a reduction to the NPC forecast. The total-company inter-regional EIM benefits included in the 2022 TAM are [redacted], an increase of [redacted] in benefits from the 2021 TAM. The GHG benefit is [redacted], a [redacted] decrease from the 2021 TAM.

IV. DETERMINATION OF NPC

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.[2]

Q. Please explain how PacifiCorp calculates NPC.

A. PacifiCorp calculates NPC for a future test period based on projected data using GRID, which is a production cost model that simulates the operation of the Company's power system on an hourly basis. As explained below, PacifiCorp is in the process of implementing a new production cost model, AURORA, but was unable to complete this transition in time to use AURORA for this filing.

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

A. Yes. PacifiCorp has used the GRID model to determine NPC in its Oregon filings since 2002. Over time, the Company has implemented various improvements to the modeling of specific items in GRID to better reflect Company operations and to achieve the most accurate NPC forecast for the test period.

Q. Has the Company proposed any changes to the GRID model in the 2022 TAM?

A. Yes. There are two changes to the GRID model for the 2022 TAM which include the removal of the "must run" setting and changes to the market caps. Both of these changes are described in greater detail below. Otherwise, PacifiCorp used the same version of the GRID model in the 2022 TAM that it used in the 2021 TAM.

Q. What inputs were updated for this filing?

A. The Company updated all inputs to the 2022 TAM, including system load, wholesale sales and purchase contracts for electricity, natural gas and wheeling, the official

[2] *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).

forward price curve (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, 2020.

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, 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. What reports does the GRID model produce?

A. The major output from the GRID model is the NPC report. This is the same information contained in Exhibit PAC/102, and an electronic version is included in the workpapers accompanying the Company's filing. Additional data with more detailed analyses are also available in hourly, daily, monthly, and annual formats by heavy load hours and light load hours.

Discussion of EIM Benefits

Q. As noted above, the total-company inter-regional EIM and GHG benefits included in the 2022 TAM are [redacted], an increase of [redacted] in benefits from the 2021 TAM. Has PacifiCorp made any changes to the methodology used to forecast EIM inter-regional and GHG benefits in the 2022 TAM?

A. No, the methodology for forecasting EIM benefits is consistent with the approach employed in the forecast used in the 2021 TAM.

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

A. The Company uses historical actual EIM inter-regional transfer benefits in statistical models to forecast EIM transfer benefits as a function of market prices and transfer volume inputs, which are the underlying drivers of actual EIM transfer benefits. The price inputs are the energy and natural gas market prices from the OFPC. The transfer volume inputs are the total transfer capacity of transmission along with spring oversupply conditions, based on the current and expected solar capacity in California. This market fundamentals approach to forecasting EIM transfer benefits mimics the method which the Company uses to calculate actual EIM transfer benefits and maintains consistency with the bilateral market price inputs that drive the Company's forecast NPC. By utilizing the same inputs, the forecast of EIM inter-regional transfer benefits, the calculation of actual EIM inter-regional transfer benefits, and the forecast NPC are aligned and produce a reasonable forecast of EIM inter-regional transfer benefits.

Q. Please explain why a methodology based on market fundamentals and the same inputs as forecast NPC produces an accurate forecast.

A. The forecast NPC is driven by expectations of market prices. These prices also drive the EIM dispatch of PacifiCorp's generation in real-time operations and the Company's EIM transfer benefits are a direct result of this generation dispatch. If PacifiCorp attempts to forecast EIM transfer benefits without taking into consideration the expectation of market prices the result will be similar to an attempt to forecast NPC without using market prices. Specifically, if forecasts of fuel costs and wholesale market transactions in NPC requires market price inputs then the forecasts of EIM transactions and associated fuel costs must also require the same market price inputs.

Q. Please explain the methodology used by CAISO to calculate actual EIM benefits.

A. CAISO calculates EIM benefits by comparing the actual costs of system dispatch to a counterfactual study that includes no transfers between the participants. CAISO uses the model that is responsible for determining transfers and dispatch instructions to calculate the benefits provided to participants. Further detail is available on the Western EIM website.[3]

Q. Please reconcile the data on the Company's latest, full-year EIM benefits (2020) with the EIM benefits forecast in the 2020 TAM.

A. In the final NPC study accompanying the 2020 TAM, the Company had a total-company forecast of $53.0 million for EIM benefits, inclusive of both inter-regional benefits and GHG benefits. As a part of the settlement stipulation, an additional

[3] *EIM Quarterly Benefit Report Methodology*, CALIFORNIA ISO (2020), *available at* https://www.westerneim.com/Documents/EIM-BenefitMethodology.pdf.

$17.0 million was added to the forecast for a total benefit of $70.0 million. Actual EIM benefits for 2020 were tabulated by CAISO at $40.6 million. The Company's calculation of actual EIM benefits for 2020 is $46.8 million. The over-forecast of EIM benefits in the 2020 TAM contributed to the Company's significant under-forecast of NPC in 2020.

Q. Why does the Company's calculation of EIM benefits differ from that of CAISO?

A. The Company does not employ CAISO's counterfactual study approach, but instead calculates EIM benefits using the more concrete approach of comparing actual costs incurred or avoided to the actual transfer payment amounts. For example, if PacifiCorp incurred an additional $1,000 in generation costs after receiving instructions to ramp production at one of its generation facilities, but was compensated $2,000 for exports in that hour, the Company would calculate a benefit of $1,000.

Market Capacity Limits

Q. Please explain the purpose of modeling market capacity limits in GRID.

A. The GRID 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 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. Without market capacity limits or caps, the GRID model has no constraints to reflect counterparties' inability to make economic transactions.

Q. Please explain how market caps have been modeled prior to this filing.

A. As a result of the Commission's order in the 2013 TAM, the Company has based its monthly market caps on "the highest of the four most recently available relevant averages for each trading hub, each month, and differentiated by on- and off-peak hours."[4] This means that PacifiCorp was required to set the market cap at the maximum monthly capacity at each trading hub for the most recent four-year period.

Q. Why is PacifiCorp proposing to change the methodology for modeling market caps?

A. PacifiCorp's original market caps methodology did not use the maximum monthly capacity and PacifiCorp opposed this revision in the 2013 TAM on the basis that it would reduce forecast accuracy—a concern that proved to be well-founded. In PacifiCorp's most recent general rate case, the Commission declined to adopt PacifiCorp's proposed annual power cost adjustment mechanism to address PacifiCorp's chronic under-recovery of NPC.[5] However, the Commission did suggest that "PacifiCorp may be able to make targeted forecast adjustments to remedy specific issues with its under-recovery."[6] Additionally, the Commission specifically pointed out that "Staff shows that PacifiCorp's sales to market (also referred to as off-system sales) are being over-forecast, finding a 'gross over-estimation of the sales

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[4] *In the Matter of PacifiCorp d/b/a Pacific Power 2013 Transition Adjustment Mechanism*, Docket No. UE 245, Order No. 12-409 at 7-8 (Oct. 29, 2012).
[5] *In the Matter of PacifiCorp d/b/a Pacific Power, Request for a General Rate Revision*, Docket No. UE 374, Order No. 20-473 at 129 (Dec. 18, 2020).
[6] *Id.* at 130.

benefit.'"[7] The Commission suggested that reducing this component of PacifiCorp's forecast is "something that may be considered in the TAM."[8] Based on the Commission's suggestion, PacifiCorp proposes revising the market cap methodology to address this concern.

Q. Please explain how the revised market cap methodology adopted in the 2013 TAM causes an over-estimation of sales.

A. The revised required methodology uses the maximum monthly capacity of the last four years which makes market caps higher, or less restrictive, without regard to whether those caps replicate actual market conditions. Consider a year where, due to weather or some other system condition, Company sales at a particular market hub during March were exceptionally high but returned to normal in April. The next year, sales at the same market hub were normal in March but exceptionally high in April. The revised methodology captures the exceptionally high sales volumes in both March and April, distorting the pattern of market behavior within a year. This allows an ongoing level of sales in GRID that is far higher than historical actual sales, undermining the accuracy of the NPC forecast and contributing to the problem of over-forecasted market sales identified by Staff in the general rate case.

Q. Please explain PacifiCorp's proposal to return to its original market cap methodology.

A. PacifiCorp has revised the GRID methodology to base wholesale sales market caps on the historical average of short-term firm, balancing and spot sales instead of the maximum of each month for the last four years. Using the four-year historical

[7] *Id.*
[8] *Id.*

average produces a more accurate approach that avoids the distortions of the revised methodology adopted in the 2013 TAM. This lowers the market caps to more accurately reflect system operations and improves the over-forecast of market sales.

For example, for the month of January, PacifiCorp would now take the average of the past four Januarys for each trading hub to develop the market cap. A lower market cap reduces the market depth at each hub, which reduces market sales modeled in GRID, and results in fewer wholesale sales which increases NPC.

Q. Please quantify the impact of the proposed change in methodology.

A. Total-company NPC increases by $19.7 million ($5.1 million on an Oregon-allocated basis), primarily driven by decreases in sales revenues. That decline in sales revenue was partially offset by reductions in coal fuel expense, natural gas fuel expense, and purchased power expense.

Removal of the "Must Run" Setting

Q. Please explain what the "must run" setting is and why the Company has included this setting for coal units in GRID in the past.

A. The "must run" setting for coal units in GRID is used to represent actual operational practice as closely as possible for normalized ratemaking purpose. In the TAM, the forecasted NPC is set on a normalized basis. GRID is designed to model the NPC with load, market conditions, prices, generation resources, and operating practices under normal conditions. Cycling coal units off and on happens infrequently in actual operations. In GRID, coal units are modeled as closely to how they are designed and used in actual operations as units that can be ramped down to their minimum operational level, but still "must run."

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. First, the "must run" setting avoids additional start-up costs that would be incurred if the units were entirely shutdown. The minimum stable operating levels at most of the Company's coal fired generation plants have been lowered over the last several years and are now low enough that a comparison of avoided fuel costs against start-up costs almost never weighs in favor of cycling a unit off outside of the spring runoff season.

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. Given the lowered minimum operating levels and an increasing quantity of low-priced renewable energy coming from the EIM, PacifiCorp's coal units provide both economic and reliable electricity and balance load, meet operational requirements, and comply with North American Electric Reliability Corporation (NERC) regulation standards.

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 GRID's overly optimized unit dispatch even more unrealistic.

Q. Has the Company conducted a study on how the removal of the "must run" setting compares to actual company operations?

A. Yes. The Company conducted a study and provided a report on economic cycling of coal units to parties in the 2021 TAM (Economic Cycling Study). This has been attached as Confidential Exhibit PAC/107 to this testimony. This report, which is based on the 2021 TAM, indicated that when the Company's coal fueled units are allowed to cycle by removing the "must run" setting, it resulted in an increase in emergency purchases. Since emergency purchases are not actual transactions available to the Company, the modeling result reflected a solution that did not reflect actual operations and could not reliably serve load.

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

A. Yes, as a result of the settlement reached in last year's TAM, PacifiCorp agreed to remove the "must run" setting as part of the transition to AURORA.[9] With the delayed transition to AURORA, the Company has removed this setting in GRID to reflect the spirit of the settlement.

Q. Were certain modeling adjustments necessary in GRID in order to remove the "must run" setting?

A. Yes. PacifiCorp had to adjust certain parameters to ensure that the model results were rational and consistent with prudent utility practice and feasible operations. For example, without a minimum up and down time, GRID may take coal units offline in

[9] *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).

one hour and then turn them to maximum in the next hour without taking into account the actual physical constraints of operating the coal units.

Q. Please explain the modeling adjustments that were necessary as a result of removing the "must run" setting in GRID?

A. The Company needed to enable certain modeling parameters regarding the individual coal units so that GRID can make rational commitment decisions. These inputs are as follows:

- Initial Commitment State – This input provides GRID with an assumption about whether the units will be online during the first hour of the study to allow GRID to make a determination on whether to cycle the units off if they are not economic in the second hour of the study. This input is not necessary if "must run" is enabled because the "must run" setting ensures the unit is online if available.
- Commitment Operating Energy – This input gives GRID a quantity of energy over which to spread the startup costs for the unit. It was set to each unit's nameplate capacity, due to the fact that full plant output can be achieved more quickly in GRID than in actual operations, owing to the lack of a ramp rate option in GRID. If the "must run" setting is enabled, then there is no evaluation of start-up costs because no cycling decision needs to be made by the model.
- Minimum up and down time – These inputs set minimum timeframes during which the unit will have to remain committed or decommitted after a commitment decision has been made. Each was set to five days (120 hours)

to reflect the physical constraints of operating the coal units. This input is not necessary if "must run" is enabled because the "must run" setting ensures the unit is online if available.

- Additional Startup Cost – This input represents the costs to start the unit. These costs are based on the Company's observed historical costs from returning a unit from outage. It is used in the commitment decision, but the charges are not reflected in NPC. If "must run" is enabled, then the unit is assumed to be running if available.

Q. Even with the modeling adjustments described above, does removal of the "must run" setting result in a less accurate forecast?

A. Yes. The removal of the "must run" setting reflects an operational 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. The dispatch of resources in actual operations is less efficient than the perfect optimization that occurs in GRID. Even with the "must-run" setting turned on, GRID's perfect foresight allows it to balance the system using market transactions that are not available and cannot be used in actual operations; GRID models more economic cycling than can occur in actual operations. Allowing GRID to increase economic cycling exacerbates the inherent differences between system optimization modeled in GRID 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.

Q. What is the impact of changing the "must run" setting in the current proceeding?

A. NPC fell very slightly in the scenario study where the "must run" setting was included, which indicates that the economic benefits of cycling the coal units are *de minimis* for the 2022 test period. However, annual coal generation increased by approximately three percent when the "must run" setting was turned on. In this counterfactual study, increased coal generation displaced natural gas generation and market purchases. These differences in generation are shown in Figure 1 below.

Figure 1
2022 Generation Differences with "Must Run" On

Description	Energy Impact (GWh)
Coal Generation	815
Gas Generation	(492)
Balancing Purchases	(261)
Balancing Sales	(62)
Total	-

Q. Why has PacifiCorp removed the "must run" setting?

A. The results demonstrate that removal of the "must run" setting in GRID fundamentally distorts NPC modeling, necessitates multiple adjustments to ensure that actual plant operations are accurately modeled, and results in little change to overall NPC results. However, consistent with the terms of the 2021 TAM settlement, PacifiCorp is providing NPC based on a GRID run that removes the "must run" setting.

V. DISCUSSION OF MAJOR COST DRIVERS IN NPC

Q. Please generally describe the changes in NPC compared to the 2021 TAM.

A. The increase in NPC is driven by a reduction in wholesale sales revenue, increased natural gas fuel expense, and increased wheeling and other expenses. Offsetting that are reductions in coal fuel expense and purchased power expense. Figure 2 illustrates the change in total-company NPC by category from the NPC baseline in the 2021 TAM.

Figure 2
Net Power Cost Reconciliation

	($ millions)	**$/MWh**
OR TAM 2021	**$1,400**	**$23.16**
Increase/(Decrease) to NPC:		
Wholesale Sales Revenue	97	
Purchased Power Expense	(10)	
Coal Fuel Expense	(114)	
Natural Gas Fuel Expense	56	
Wheeling and Other Expense	17	
Total Increase/(Decrease) to NPC	**45**	
OR TAM 2022	**$1,445**	**$23.87**

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 $97 million lower than the 2021 TAM with most of the reduction coming from market transactions (represented in GRID as short-term firm and system balancing sales). Market sales transactions in the 2022 TAM are 2,139 gigawatt-hours (GWh) lower than in the 2021 TAM. The reduction is exacerbated by slightly lower forecasted sale prices during 2022. The average market price of wholesale sales in the 2022 TAM is $36.54/megawatt-hour (MWh), while in the 2021 TAM the average market price was $38.63/MWh, a five 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 GRID 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 2022 TAM compare to the historical period?

A. In the 2022 TAM, long-term firm wholesale sales revenue remains flat from the 2021 TAM. The system balancing sales revenue only changes slightly as compared to the system balancing sales from the historical period.

The short-term firm revenue in this filing is at a lower level than what is reflected in the final update of the prior TAM proceedings. This is because the short-term firm sales are the actual short-term firm transactions, or hedges, the Company has entered into for the test period. The Company hedges on a rolling 36-month horizon but the majority of the trading activity is for the next 12 months. Therefore, the final TAM filed in November will have larger volumes of short-term firm sales than the initial TAM filing due to the 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 purchased power expense decrease?

A. The $10 million decrease in purchased power expense is primarily due to lower market purchase prices. The average price of the long-term contracts included in the 2022 TAM is $42.98/MWh, compared to the average price of long-term contracts in the 2021 TAM of $43.56/MWh. Market purchases (represented in GRID as short-term firm and system balancing purchases) in the current case have an average price of $24.48/MWh, while the 2021 TAM was an average price of $21.16/MWh.

Total-company expense for power purchased from Qualifying Facilities (QF) increased by $1.6 million with a small increase in the generation volume compared to the 2021 TAM.

No new QFs are forecast to come online in the 2022 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 $114 million lower than the 2021 TAM due to the lower coal generation volume at the Company's coal plants. In addition, average coal prices are $0.42/MWh lower than prices in the 2021 TAM. The decrease is driven by changes in third-party coal supply and rail contracts since last year's TAM.

Mr. Ralston provides additional detail regarding the cost of coal during the test period in his direct testimony.

Q. Please discuss the change in natural gas fuel expense compared to the 2021 TAM.

A. Total-company natural gas fuel expense in the 2022 TAM is $56 million higher than natural gas fuel expense in the 2021 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 $25.79/MWh in the 2021 TAM to $23.97/MWh in the current proceeding, a seven percent decrease. Generation from natural gas plants in the 2022 TAM is 3,156 GWh more than the 2021 TAM, a 29 percent increase.

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

A. Expenses in this category are $17 million higher primarily due to an update based on actual 2020 wheeling expenses. In addition, the removal of the settlement adjustment for this year's study increased the cost in this category by a further $8.8 million total company.

Q. How does the forecast wind generation compare to the 2021 TAM?

A. Some Company-owned resources that experienced construction delays are forecast to be at full production during 2022 which increased owned wind generation by 902 GWh, a 13 percent increase from the amount in the 2021 TAM.

Q. What updates are expected in the Company's resource portfolio relative to the 2021 TAM?

A. The Company updated minimum operation levels for four thermal units. The impacts are included in Step 3 of Exhibit PAC/104, the Step Log.

Q. Was the Day Ahead/Real Time (DA/RT) adjustment calculated in the same manner as in the 2021 TAM?

A. Yes. The DA/RT adjustment calculated in this filing was calculated with the same methodology used in the 2021 TAM.

Q. What is the purpose of the DA/RT adjustment?

A. The DA/RT adjustment is used to better reflect system balancing costs that are not fully captured in the GRID 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.

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 to the Company's modeling of NPC in the 2022 TAM. This notice was provided on March 1, 2021, and is included as Exhibit PAC/105.

VI. COMPLIANCE WITH 2021 TAM ORDER

Q. The 2021 TAM order described a number of 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.[10] PacifiCorp agreed to the following:

- Hold a workshop on the transition from GRID to AURORA prior to filing a net power cost 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;
- 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. Please explain why the AURORA model was not available to be used in time for the 2022 TAM.

A. As a result of certain delays related to the COVID-19 pandemic, the expected timeline for implementing the AURORA model has been extended. The implementation timeline has only been delayed a few months and PacifiCorp fully expects to have the AURORA model available for use in the 2023 TAM.

Q. Has PacifiCorp reached out to stakeholders regarding the delay in the implementation of the AURORA model for this TAM?

A. Yes, PacifiCorp reached out to Staff, the Oregon Citizens' Utility Board (CUB), the Alliance of Western Energy Consumers (AWEC), Calpine, and Sierra Club, and held a meeting with these stakeholders on February 25, 2021, to discuss the delay in implementing AURORA.

[10] *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).

Q. A number of the provisions in the stipulation from the 2021 TAM discuss the use of the AURORA modeling software. Will PacifiCorp still be complying with those provisions?

A. In general, yes, PacifiCorp will still be providing the requested model runs referenced in the stipulation, except they will be conducted with GRID instead of AURORA. PacifiCorp will also be conducting the AURORA workshop next year prior to the implementation of AURORA for the 2023 TAM. Finally, PacifiCorp has removed the "must-run" setting from the coal units in GRID, which is discussed above. PacifiCorp has committed to comply with provisions regarding the AURORA transition in the stipulation when that transition occurs.

Q. Does PacifiCorp's direct testimony in this proceeding contain the additional information that was stipulated to in the 2021 TAM?

A. Yes. The following table lists the information that was requested as part of the order in the 2021 TAM and describes where it has been provided:

Figure 3

Request	Details
Provide additional information on coal supply agreements by providing testimony in the initial TAM filing regarding the prudence of any coal supply agreements that were entered into since the previous year's reply testimony	Provided in the direct testimony of Mr. Ralston, Exhibit PAC/200.
Provide quarterly reports on plant operations and conduct an economic cycling study;	To be scheduled with Parties after the completion of Q1 2021 in April/May
Provide additional information on wholesale sales, including: the past year's bilateral trades for each hour ($/MWh), total wholesale sales revenue ($), total energy delivered through wholesale sales (MWh), hourly generation for PacifiCorp-owned generation, and monthly generation unit production costs ($/MWh);	Provided with the concurrent workpapers in this filing.
Provide additional information on CAISO's calculation of EIM benefits and make supporting documentation available for review;	Provided in this testimony, Section IV.
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 within 30 days of this filing.
Provide an explanation and quantify the other NPC benefits from PacifiCorp's wind projects, 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;	Provided in this testimony, Section VII.
Address whether it is reasonable for TAM rates to include coal costs required by minimum take delivery levels that may be uneconomic at Huntington, or whether forecasts should be set based on economic delivery level without reference to minimum take.	Provided in this testimony, Section VIII, and the testimony of Mr. Ralston, Exhibit PAC/200.

VII. PRODUCTION TAX CREDITS 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 2022 TAM?

A. Yes. The NPC and PTC benefits of all new wind projects are included in the 2022 TAM. These include the Energy Vision 2020 Wind Projects, which are 1,150 megawatts (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 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 2022 TAM.

A. The 2022 TAM includes changes in projected levels of PTCs. Confidential Exhibit PAC/103 shows the forecast level of PTCs for 2022 compared to the level of PTCs established in the 2021 TAM. The forecast value of Oregon-allocated PTCs for the 2022 test period is approximately \$66.2 million, which is higher than the \$56.7 million included in the 2021 TAM, resulting in a decrease to the 2022 TAM of \$9.5 million.

Q. How are PTCs calculated for the 2022 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 2.5 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 2022 TAM.

A. As seen in Confidential Figure 1 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 7,545,687 MWh. The total tax-adjusted PTCs on an Oregon-allocated basis are $66.2 million.

Confidential Figure 4
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 2022	CY 2022 Initial Filing	Revenue Requirement *(See Note 1)*
Glenrock	[redacted]	99.0	[redacted]	[redacted]	26.482%	[redacted]	[redacted]
Glenrock III	[redacted]	39.0	[redacted]	[redacted]	26.482%	[redacted]	[redacted]
Goodnoe Hills	[redacted]	94.0	[redacted]	[redacted]	26.482%	[redacted]	[redacted]
High Plains Wind	[redacted]	99.0	[redacted]	[redacted]	26.482%	[redacted]	[redacted]
Leaning Juniper 1	[redacted]	100.5	[redacted]	[redacted]	26.482%	[redacted]	[redacted]
Marengo	[redacted]	156.0	[redacted]	[redacted]	26.482%	[redacted]	[redacted]
Marengo II	[redacted]	78.0	[redacted]	[redacted]	26.482%	[redacted]	[redacted]
McFadden Ridge	[redacted]	28.5	[redacted]	[redacted]	26.482%	[redacted]	[redacted]
Seven Mile	[redacted]	99.0	[redacted]	[redacted]	26.482%	[redacted]	[redacted]
Seven Mile II	[redacted]	19.5	[redacted]	[redacted]	26.482%	[redacted]	[redacted]
Dunlap I Wind	[redacted]	111.0	[redacted]	[redacted]	26.482%	[redacted]	[redacted]
Foote Creek I Wind	[redacted]	41.4	[redacted]	[redacted]	26.482%	[redacted]	[redacted]
Pryor Mountain Wind	[redacted]	239.8	[redacted]	[redacted]	26.482%	[redacted]	[redacted]
Cedar Springs Wind II	[redacted]	200.0	[redacted]	[redacted]	26.482%	[redacted]	[redacted]
Ekola Flats Wind	[redacted]	250.0	[redacted]	[redacted]	26.482%	[redacted]	[redacted]
TB Flats Wind	[redacted]	247.3	[redacted]	[redacted]	26.482%	[redacted]	[redacted]
TB Flats Wind II	[redacted]	252.7	[redacted]	[redacted]	26.482%	[redacted]	[redacted]
Total Production Tax Credit	$ 188,642,173	2,154.7		7,545,687		$ 49,955,423	$ 66,242,104

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 & 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 2022 is approximately $111 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 2022 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[.]"[11]

A. When PacifiCorp removed the new wind from the NPC forecast in GRID, 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 Figure 5 below.

Figure 5
Impact of the Removal of New Wind Resources

Description	Cost Impact ($millions)		Energy Impact (GWh)
Removal of Resources	$	(20.6)	(5,335)
Coal Generation	$	76.2	3,535
Gas Generation	$	7.7	384
Balancing Purchases	$	41.4	1,182
Balancing Sales	$	6.3	233
Total	$	110.9	-

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 3,535 GWh of increased coal generation resulting in $76.2 million in increased total-company NPC. Additionally, the new wind projects avoided 1,182 GWh of system

[11] *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).

balancing purchases at a cost of $41.4 million. The contribution of the new wind projects reduces NPC by nearly $111 million total company, avoids significant market purchases, and reduces coal generation for 2022. This only reflects one year of NPC benefits for customers and is incremental to the significant PTC benefits associated with these new resources.

VIII. REQUESTED INFORMATION ON HUNTINGTON

Q. In the 2021 TAM Order, the Commission raised concerns about the modeling of PacifiCorp's coal delivery from the Huntington plant. Specifically the Commission asked "parties to address whether it is reasonable for TAM rates to include coal costs required by minimum take delivery levels that may be uneconomic, or whether forecasts should be set based on the economic delivery level without reference to the minimum take."[12] How is this request addressed in testimony?

A. Mr. Ralston's testimony, Exhibit PAC/200, discusses why PacifiCorp's coal contracts have minimum take provisions and provides context on how the Huntington coal supply agreement facilitated closure of the Deer Creek Mine. I address why PacifiCorp's modeling of Huntington continues to be appropriate and reflective of actual Company operations.

Q. Please explain how GRID arrives at the optimal economic forecast of coal generation volumes considering minimum take requirements.

A. Coal volumes are determined by GRID based on the economic dispatch of each coal plant. The dispatch in GRID is a result of logic that supports only a single

[12] Order No. 20-392 at 10.

incremental fuel price input value in the dispatch decision for each coal unit. Consequently, iterative GRID runs may be necessary to ensure that coal burn volumes are consistent with minimum take requirements across the coal fleet. If the coal volumes determined by GRID are below the minimum take requirements at a given coal plant, the incremental coal price input is adjusted down (driving up consumed coal volume as determined by GRID) until the minimum coal volume is achieved. The coal volumes in the TAM forecast satisfy both the economic dispatch logic and the minimum take requirement. The Company has used this method in every TAM proceeding and the Commission explicitly affirmed this modeling methodology in the 2017 TAM (docket UE 307).[13]

Q. Please explain how the Company accounts for minimum-take requirements.

A. As referenced above, GRID only supports a single incremental price input for use in determining its optimal unit dispatch forecast. As a result, the Company accounts for minimum-take provisions by using an iterative process to arrive at an incremental fuel price that ensures the plants burn at least the volume required to be purchased under the minimum-take provision of the applicable coal supply agreements. GRID cannot accommodate a contractual minimum-take provision, so this is the mechanism employed to ensure those contractual provisions are respected. The approach taken in GRID recognizes that minimum-take provisions impose costs that the Company incurs regardless of whether the minimum volumes are burned. As a previously incurred cost that cannot be avoided, it makes economic sense to ensure that at least these volumes are burned because they have an effective incremental price of zero.

[13] *In the Matter of PacifiCorp d/b/a Pacific Power 2017 Transition Adjustment Mechanism*, Docket No. UE-307, Order No. 16-482 at 10-11 (Dec. 20, 2016).

Forgoing that generation and replacing it with energy from other sources (market purchases, other units, etc.) would have the effect of simply increasing NPC by the cost of the replacement power.

Q. Please explain the iterative process for the Huntington coal contract in the 2022 TAM forecast.

A. The Company first executed a GRID study to determine the fuel consumption for Huntington with the dispatch tier price set at the price of the incremental tier. However, that forecasted consumption was below the minimum purchase requirement present in the fuel supply contract. As a consequence of the fact that failing to meet those contractual obligations inherently increases costs for customers, the dispatch tier prices were revised downward until Huntington cleared its minimum purchase obligation while continuing to review the overall reasonableness of the study results. In this way, the model minimizes costs, while taking into account these reasonable, industry standard, and prudent contract provisions.

Q. Please explain how this iterative process reflects the costs that are actually incurred in PacifiCorp's operations.

A. The Company forecasts generation from coal-fired resources in a manner consistent with how those resources are deployed to serve load in its actual operations. Figure 6 below displays the percentage of total requirements served by coal generation from 2012 to 2020.

Figure 6

	Coal Generation		
Year	Actual (%)	TAM (%)	Difference
2012	60%	60%	0.31%
2013	62%	60%	1.95%
2014	60%	59%	1.22%
2015	61%	59%	1.61%
2016	56%	51%	5.17%
2017	56%	54%	2.54%
2018	54%	55%	-0.23%
2019	53%	48%	5.81%
2020	48%	45%	3.17%
Average	57%	55%	2.39%

In actual operations, the Company has only fallen below the threshold set in the TAM during a single year, 2018. In fact, the TAM frequently understates the percentage of requirements that are served by coal-fired resources, though that understatement is slight, which indicates that the current approach is valid for producing an accurate NPC forecast.

Q. **Does the iterative process described above better reflect actual operations?**

A. Yes. The iterative process at Huntington and other coal plants reflects the economic realities of power plant operation with a minimum-take coal contract. Additionally, in actual operations, the Company consistently runs Huntington because it is required to maintain reliability and system flexibility.

Q. **How do actual operations depart from GRID?**

A. While GRID has perfect foresight, in actual operations there is much more uncertainty, including weather, renewable resource shape, load, and outages. The Company is making dispatch decisions based on the best available information, such as short-term load and renewable forecasts. That information, however, is inherently imperfect and the Company is therefore making dispatch decisions without perfect foresight into system conditions, which are constantly changing. The system flexibility from the coal units is necessary in actual operations due to the unpredictable nature of system conditions and intermittent generation from renewable resources. This system flexibility helps support the integration of new renewable resources which result in significant NPC benefits for customers.

Q. Is it appropriate to exclude costs in a manner that does not reflect actual operations?

A. No. As referenced earlier in my testimony, the Commission has articulated the importance of accurate NPC modeling in the TAM. The contract provisions that lead to these modeling conventions are real and reflective of the conditions of the markets in which the Company must do business, given the geographic footprint of its generation facilities. They have been scrutinized and accepted as prudent in past proceedings, and they remain in effect. They are the natural outcome of the least-cost, least-risk fueling plan employed by the Company, and they allow the Company to safely and reliably operate its resources. The modeling in GRID and the overall formulation of the cost estimates presented annually in the TAM are simply reflective of this reality.

IX. 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.[14] 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.[15]

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.

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

[14] *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).
[15] *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).

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 2022 TAM consistent with the stipulation filed in the 2020 TAM?[16]

A. Yes.

X. 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 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.[17]

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

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

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.

XI. 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.

Q. Did the Company provide information regarding its anticipated TAM updates?

A. Yes. Exhibit PAC/106 contains a list of known contracts and other items that are included in the Company's TAM updates in this case based on the best information available at the time the Company prepared the NPC study.

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 GRID model and workpapers concurrently with this initial filing. Specifically, the Company provided the NPC report workbook and the GRID 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/104.

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. UE 390
Exhibit PAC/101
Witness: David G. Webb

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of David G. Webb

Oregon-Allocated Net Power Costs

April 2021

PacifiCorp
CY 2022 TAM
Initial Filing

Line no		ACCT.	Total Company: UE-375 CY 2021 - Final Update	Total Company: TAM CY 2022 - Initial Filing	Factor	Factors CY 2021	Factors CY 2022	Oregon Allocated: UE-375 CY 2021 - Final Update	Oregon Allocated: TAM CY 2022 - Initial Filing
1	**Sales for Resale**								
2	Existing Firm PPL	447	7,802,619	7,588,544	SG	26.023%	26.482%	2,030,447	2,009,566
3	Existing Firm UPL	447	-	-	SG	26.023%	26.482%	-	-
4	Post-Merger Firm	447	341,463,801	244,865,802	SG	26.023%	26.482%	88,857,870	64,844,327
5	Non-Firm	447	-	-	SE	25.101%	25.369%	-	-
6	**Total Sales for Resale**		349,266,420	252,454,345				90,888,317	66,853,893
7									
8	**Purchased Power**								
9	Existing Firm Demand PPL	555	10,522,213	8,522,609	SG	26.023%	26.482%	2,738,157	2,256,921
10	Existing Firm Demand UPL	555	2,364,360	13,745,556	SG	26.023%	26.482%	615,269	3,640,040
11	Existing Firm Energy	555	32,904,819	48,266,029	SE	25.101%	25.369%	8,259,599	12,244,782
12	Post-merger Firm	555	627,875,283	593,272,567	SG	26.023%	26.482%	163,389,678	157,107,935
13	Secondary Purchases	555	-	-	SE	25.101%	25.369%	-	-
14	Other Generation Expense	555	-	-	SG	26.023%	26.482%	-	-
15	**Total Purchased Power**		673,666,674	663,806,761				175,002,703	175,249,678
16									
17	**Wheeling Expense**								
18	Existing Firm PPL	565	21,615,814	21,996,429	SG	26.023%	26.482%	5,625,004	5,825,001
19	Existing Firm UPL	565	-	-	SG	26.023%	26.482%	-	-
20	Post-merger Firm	565	114,818,653	110,442,896	SG	26.023%	26.482%	29,878,836	29,247,021
21	Non-Firm	565	2,694,259	15,162,218	SE	25.101%	25.369%	676,299	3,846,557
22	**Total Wheeling Expense**		139,128,726	147,601,542				36,180,139	38,918,580
23									
24	**Fuel Expense**								
25	Fuel Consumed - Coal	501	657,614,065	543,415,251	SE	25.101%	25.369%	165,070,915	137,860,962
26	Fuel Consumed - Coal (Cholla)	501	-	-	SE	25.101%	25.369%	-	-
27	Fuel Consumed - Gas	501	6,268,061	7,548,171	SE	25.101%	25.369%	1,573,376	1,914,923
28	Natural Gas Consumed	547	274,027,051	327,262,235	SE	25.101%	25.369%	68,784,867	83,024,329
29	Simple Cycle Comb. Turbines	547	3,234,523	4,308,331	SE	25.101%	25.369%	811,913	1,092,996
30	Steam from Other Sources	503	4,508,022	3,966,594	SE	25.101%	25.369%	1,131,580	1,006,299
31	**Total Fuel Expense**		945,651,721	886,500,582				237,372,653	224,899,509
32									
33	TAM Settlement Adjustment*		(8,802,107)	-		As Settled		(2,250,000)	-
34									
35	**Net Power Cost (Per GRID)**		1,400,378,595	1,445,454,540				355,417,177	372,213,874
36									
37	Oregon Situs NPC Adustments		1,102,774	(1,645,063)	OR	100.000%	100.000%	1,102,774	(1,645,063)
38	**Total NPC Net of Adjustments**		1,401,481,369	1,443,809,477				356,519,952	370,568,810
39									
40	Production Tax Credit (PTC)		(217,892,375)	(250,144,103)	SG	26.023%	26.482%	(56,701,332)	(66,242,104)
41	**Total TAM Net of Adjustments**		1,183,588,994	1,193,665,374				299,818,620	304,326,706
42									
43							Increase Absent Load Change		4,508,086
44									
45							Oregon-allocated NPC (incl. PTC) Baseline in Rates from UE-375	$299,818,620	
46							$ Change due to load variance from UE-375 forecast	3,293,946	
47							2022 Recovery of NPC (incl. PTC) in Rates	$303,112,566	
48									
49	*TAM Settlement UE 375 - Agreed to decrease Oregon-allocated NPC by $2,250,000						**Increase Including Load Change**		**$ 1,214,140**

Docket No. UE 390
Exhibit PAC/102
Witness: David G. Webb

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of David G. Webb

Net Power Costs Report

April 2021

PacifiCorp

ORTAM22 NPC Direct Final

Net Power Cost Analysis

$

12 months ended December 2022	01/22-12/22	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22
Special Sales For Resale													
Long Term Firm Sales													
Black Hills	7,588,544	737,400	508,924	478,077	449,874	427,935	614,441	741,768	738,812	715,650	725,455	712,851	737,358
BPA Wind	-	-	-	-	-	-	-	-	-	-	-	-	-
East Area Sales (WCA Sale)	-	-	-	-	-	-	-	-	-	-	-	-	-
Hurricane Sale	7,453	623	623	623	623	623	623	623	623	623	623	623	603
LADWP (IPP Layoff)	-	-	-	-	-	-	-	-	-	-	-	-	-
Leaning Juniper Revenue	111,022	7,742	7,225	10,583	4,289	5,050	7,564	16,094	16,193	11,693	8,955	7,147	8,486
SMUD	-	-	-	-	-	-	-	-	-	-	-	-	-
UMPA II s45631	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Long Term Firm Sales	7,707,019	745,764	516,772	489,283	454,785	433,607	622,628	758,485	755,628	727,965	735,034	720,621	746,446
Short Term Firm Sales													
COB	-	-	-	-	-	-	-	-	-	-	-	-	-
Colorado	-	-	-	-	-	-	-	-	-	-	-	-	-
Four Corners	3,818,140	1,330,990	1,183,080	1,304,070	-	-	-	-	-	-	-	-	-
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	3,818,140	1,330,990	1,183,080	1,304,070	-	-	-	-	-	-	-	-	-
System Balancing Sales													
COB	30,334,771	3,552,571	2,078,082	2,353,278	992,592	1,261,968	2,369,581	2,110,102	2,041,175	2,249,701	3,632,880	4,161,230	3,531,611
Four Corners	54,426,727	5,248,975	4,224,416	1,898,479	2,531,641	1,858,918	3,931,071	7,048,789	6,669,838	6,028,363	5,521,513	5,168,984	4,295,739
Mead	30,267,548	4,302,157	3,274,411	1,584,918	836,837	850,771	1,599,941	1,665,896	3,340,323	3,047,212	3,175,853	2,891,410	3,697,819
Mid Columbia	37,542,887	2,532,506	715,130	980,426	1,317,640	945,355	2,568,308	7,515,901	7,989,864	4,502,364	3,438,663	2,639,115	2,397,614
Mona	26,760,880	2,987,887	1,815,567	611,719	863,023	1,059,514	2,028,992	2,363,576	2,934,044	6,087,999	2,518,250	1,882,279	1,608,031
NOB	7,107,251	79,033	73,671	443,689	655,488	35,963	11,241	1,601,073	1,816,591	945,131	14,775	88,141	1,342,455
Palo Verde	54,485,976	4,098,422	2,116,681	4,700,795	2,588,829	2,912,984	4,864,244	10,014,772	11,340,198	6,583,864	2,882,641	1,311,339	1,071,205
Trapped Energy	3,146	1,987	-	-	1,159	-	-	-	-	-	-	-	-
Total System Balancing Sales	240,929,186	22,803,538	14,297,960	12,573,304	9,787,209	8,925,473	17,373,377	32,320,108	36,132,034	29,444,633	21,184,576	18,142,498	17,944,474
Total Special Sales For Resale	252,454,345	24,880,293	15,997,812	14,366,657	10,241,995	9,359,080	17,996,006	33,078,593	36,887,662	30,172,599	21,919,610	18,863,119	18,690,920

Purchased Power & Net Interchange

Long Term Firm Purchases													
Appaloosa 1A Solar	-	-	-	-	-	-	-	-	-	-	-	-	-
Appaloosa 1B Solar	-	-	-	-	-	-	-	-	-	-	-	-	-
APS Supplemental	-	-	-	-	-	-	-	-	-	-	-	-	-
Avoided Cost Resource	-	-	-	-	-	-	-	-	-	-	-	-	-
Castle Solar	-	-	-	-	-	-	-	-	-	-	-	-	-
Cedar Springs Wind	11,723,273	1,348,849	1,095,201	1,032,244	1,016,035	830,825	743,881	742,782	585,990	827,498	1,090,534	1,068,343	1,341,093
Cedar Springs Wind III	8,908,095	1,025,294	832,067	784,236	772,110	631,271	565,348	564,366	445,200	628,830	828,668	811,823	1,018,881
Combine Hills Wind	5,503,295	382,039	462,911	561,303	561,021	477,253	410,331	463,102	388,216	366,716	381,506	467,770	581,128
Cove Mountain Solar	3,863,173	184,607	194,698	339,380	369,458	425,244	457,335	443,628	419,763	359,961	289,769	208,202	171,128
Cove Mountain Solar II	9,546,217	458,099	481,285	838,933	913,284	1,051,185	1,130,513	1,096,629	1,037,640	889,811	716,297	511,782	420,758
Deseret Purchase	34,229,844	2,840,094	2,915,123	2,727,550	2,624,384	2,557,393	2,653,860	3,059,823	3,059,823	3,027,668	3,033,027	2,746,307	2,984,794
Douglas PUD Settlement	-	-	-	-	-	-	-	-	-	-	-	-	-
Eagle Mountain - UAMPS/UMPA	475,009	176,342	157,638	141,029	-	-	-	-	-	-	-	-	-
Gemstate	1,717,824	143,152	143,152	143,152	143,152	143,152	143,152	143,152	143,152	143,152	143,152	143,152	143,152
Georgia-Pacific Camas	-	-	-	-	-	-	-	-	-	-	-	-	-
Graphite Solar	6,310,360	315,660	357,582	564,720	619,747	695,093	713,257	695,674	650,775	583,233	486,296	359,441	268,882
Hermiston Purchase	-	-	-	-	-	-	-	-	-	-	-	-	-
Horseshoe Solar	2,667,232	-	-	-	-	-	21,926	649,761	615,683	512,127	411,472	254,320	201,944
Hunter Solar	7,120,458	373,103	425,031	647,514	675,791	770,602	797,429	758,093	712,635	664,479	567,050	402,182	326,550
Hurricane Purchase	165,035	13,790	13,790	13,790	13,790	13,790	13,790	13,790	13,790	13,790	13,790	13,790	13,345
IPP Purchase	-	-	-	-	-	-	-	-	-	-	-	-	-
MagCorp	-	-	-	-	-	-	-	-	-	-	-	-	-
MagCorp Reserves	4,439,070	372,930	368,920	372,930	376,940	376,940	376,940	372,930	372,930	344,860	364,910	372,930	364,910
Milican Solar	2,735,535	70,656	142,907	211,909	266,728	316,578	344,588	388,056	342,899	275,962	180,695	115,734	78,823
Milford Solar	7,078,933	358,636	412,994	609,192	677,611	796,634	839,927	747,990	720,080	671,702	541,717	393,922	308,528
Nucor	7,129,800	594,150	594,150	594,150	594,150	594,150	594,150	594,150	594,150	594,150	594,150	594,150	594,150
Old Mill Solar	-	-	-	-	-	-	-	-	-	-	-	-	-
Monsanto Reserves	19,999,999	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667
Pavant III Solar	-	-	-	-	-	-	-	-	-	-	-	-	-
PGE Cove	154,785	12,899	12,899	12,899	12,899	12,899	12,899	12,899	12,899	12,899	12,899	12,899	12,899
Prineville Solar	1,855,952	84,387	94,943	140,787	177,207	210,326	228,936	257,815	227,812	183,342	120,049	76,891	53,456
Rock River Wind	-	-	-	-	-	-	-	-	-	-	-	-	-
Rocket Solar	2,835,362	-	-	-	-	-	23,391	722,941	654,156	549,984	418,234	255,513	211,145
Sigurd Solar	5,975,468	311,168	349,111	514,891	562,169	646,129	710,144	660,236	605,234	565,052	458,516	322,228	270,590
Small Purchases east	14,288	1,173	1,213	1,172	1,172	1,233	1,203	1,226	1,202	1,153	1,157	1,209	1,176
Small Purchases west	-	-	-	-	-	-	-	-	-	-	-	-	-
Soda Lake Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-
Three Buttes Wind	20,662,796	2,790,663	1,806,921	2,135,557	1,618,738	1,425,615	1,202,984	807,052	950,561	1,186,424	1,734,559	2,352,376	2,651,346
Top of the World Wind	40,686,138	5,436,527	3,612,759	4,244,151	3,270,658	2,907,364	2,399,806	1,720,417	1,872,120	2,296,841	3,513,203	4,491,632	4,920,662
Tri-State Purchase	-	-	-	-	-	-	-	-	-	-	-	-	-
West Valley Toll	-	-	-	-	-	-	-	-	-	-	-	-	-
Wolverine Creek Wind	10,383,110	769,734	899,379	1,146,384	1,053,092	797,120	854,930	677,617	645,569	761,818	837,862	974,504	965,102
UT Solar Adjustment	(16,666,690)	(414,201)	(477,740)	(1,042,097)	(1,171,607)	(1,386,720)	(1,435,264)	(2,716,268)	(2,504,068)	(2,084,147)	(1,671,741)	(1,020,665)	(742,172)
Long Term Firm Purchases Total	199,514,361	19,316,416	16,563,602	18,402,441	16,815,194	15,960,743	15,472,120	14,544,527	14,234,876	15,043,970	16,734,437	17,597,100	18,828,935
Seasonal Purchased Power													
Constellation 2013-2016	-	-	-	-	-	-	-	-	-	-	-	-	-
Seasonal Purchased Power Total	-	-	-	-	-	-	-	-	-	-	-	-	-

Qualifying Facilities													
QF California	1,902,679	163,249	173,228	206,367	213,190	193,827	159,830	135,470	130,990	124,044	128,460	126,768	147,256
QF Idaho	7,810,528	573,458	544,507	616,157	657,344	785,767	786,308	783,759	601,033	595,467	566,356	620,903	679,467
QF Oregon	49,937,557	2,816,374	3,039,022	4,043,489	5,091,159	5,453,073	5,759,503	5,594,623	5,345,031	4,539,685	3,448,717	2,374,111	2,432,770
QF Utah	12,231,113	839,984	877,255	1,051,847	1,084,702	1,187,127	1,208,132	1,125,751	1,123,640	1,055,515	995,069	879,433	802,658
QF Washington	216,205	-	-	18	7,862	21,692	36,692	50,765	52,345	35,072	11,760	-	-
QF Wyoming	86,270	10,075	8,452	10,106	6,275	5,030	3,054	8,330	7,517	4,210	5,954	6,819	10,449
Biomass One QF	15,614,593	1,267,642	1,228,421	1,357,350	1,636,955	1,044,080	1,026,284	1,488,106	1,433,188	1,421,889	1,486,118	1,457,169	767,392
Boswell Wind I QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Boswell Wind II QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Boswell Wind III QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Boswell Wind IV QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Chevron Wind QF	-	-	-	-	-	-	-	-	-	-	-	-	-
DCFP QF	139,316	2,743	3,567	3,185	2,805	2,948	5,173	24,662	29,990	34,573	14,761	7,560	7,350
Enterprise Solar I QF	12,473,865	611,340	752,602	974,573	1,106,815	1,245,131	1,370,394	1,537,557	1,507,789	1,173,477	949,861	701,600	542,727
Escalante Solar I QF	11,515,430	561,065	680,346	877,315	1,006,345	1,178,752	1,294,854	1,422,267	1,392,895	1,088,207	869,085	638,954	505,344
Escalante Solar II QF	10,840,674	527,342	638,583	826,601	946,673	1,115,326	1,224,571	1,345,889	1,306,789	1,025,478	814,388	597,862	471,171
Escalante Solar III QF	10,442,698	513,699	623,725	800,706	921,256	1,088,119	1,195,182	1,307,177	1,270,302	996,975	745,740	547,944	431,874
Evergreen BioPower QF	-	-	-	-	-	-	-	-	-	-	-	-	-
ExxonMobil QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Five Pine Wind QF	8,693,307	533,253	875,763	777,746	820,996	506,256	552,652	642,720	619,325	779,838	765,907	901,916	916,935
Foote Creek III Wind QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Glen Canyon A Solar QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Glen Canyon B Solar QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Granite Mountain East Solar QF	10,835,774	544,536	614,654	890,473	982,087	1,146,476	1,246,724	1,326,384	1,264,408	972,504	804,390	577,936	465,202
Granite Mountain West Solar QF	7,172,267	360,727	406,976	590,987	651,525	758,979	823,975	877,723	835,347	644,272	532,107	381,598	308,051
Iron Springs Solar QF	11,121,950	629,316	662,149	891,964	1,009,338	1,120,393	1,271,634	1,333,691	1,321,374	1,000,417	810,606	574,043	497,025
Kennecott Refinery QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Kennecott Smelter QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Latigo Wind Park QF	9,674,442	1,007,478	917,570	1,126,955	897,120	856,897	745,979	668,253	572,323	616,686	799,252	709,690	756,240
Monticello Wind QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Mountain Wind 1 QF	8,905,879	1,392,508	1,039,745	867,285	684,928	476,623	503,274	411,828	442,266	469,755	671,689	911,019	1,034,959
Mountain Wind 2 QF	13,899,125	2,030,291	1,559,123	1,351,134	1,069,087	746,021	905,871	764,010	737,182	777,975	1,008,414	1,412,658	1,537,361
North Point Wind QF	19,444,476	1,119,817	1,887,393	1,734,776	1,844,679	1,128,968	1,254,304	1,494,039	1,533,687	1,852,541	1,780,259	1,917,468	1,896,546
Oregon Wind Farm QF	12,470,313	721,155	966,803	1,118,155	1,283,514	1,266,915	1,218,352	1,255,449	1,120,480	935,736	749,587	788,767	1,045,402
Pavant II Solar QF	4,959,080	201,315	257,063	378,853	435,113	513,729	569,251	656,296	656,880	489,779	363,926	241,028	195,849
Pioneer Wind Park I QF	10,649,365	1,304,319	924,970	1,187,417	905,678	708,589	651,185	653,415	683,216	455,095	819,798	1,259,137	1,096,547
Power County North Wind QF	5,647,194	431,651	569,790	542,537	530,314	367,152	360,809	373,188	380,639	393,029	530,965	541,512	625,608
Power County South Wind QF	5,029,309	381,165	501,482	489,271	492,038	316,908	320,949	329,324	354,756	347,971	464,720	488,211	542,514
Roseburg Dillard QF	1,004,727	44,544	51,457	27,164	104,964	107,167	90,090	165,876	136,493	67,667	77,977	77,698	53,631
Sage I Solar QF	2,256,857	80,192	79,413	189,005	204,759	233,577	261,123	333,738	333,817	207,287	154,769	104,237	74,940
Sage II Solar QF	2,259,283	80,277	79,507	189,206	204,979	233,788	261,418	334,095	334,187	207,522	154,927	104,366	75,010
Sage III Solar QF	1,859,270	67,598	66,161	156,107	166,890	191,458	213,576	272,357	272,200	171,079	129,834	88,345	63,665
Spanish Fork Wind 2 QF	2,778,082	219,288	178,796	202,762	161,385	155,649	216,228	294,704	317,649	274,406	243,899	252,418	260,899
Sunnyside QF	30,732,217	2,358,217	2,207,189	2,528,442	2,068,107	2,776,639	2,790,251	2,806,797	2,767,405	2,627,199	2,412,417	2,803,191	2,586,363
Sweetwater Solar QF	7,734,664	257,166	371,747	562,483	683,975	807,847	977,678	1,106,980	1,036,166	809,400	623,027	297,691	200,503
Tesoro QF	311,916	47,813	35,401	28,397	19,853	28,051	7,603	14,430	23,225	20,823	20,541	20,826	44,953
Threemile Canyon Wind QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Three Peaks Solar QF	8,416,119	410,321	476,104	625,734	829,197	852,526	905,095	1,035,085	1,006,568	792,565	668,252	442,169	372,504
Utah Pavant Solar QF	6,436,976	239,669	277,573	474,672	558,189	659,215	736,618	874,649	828,307	689,619	508,949	323,716	265,801
Utah Red Hills Solar QF	11,525,396	482,179	617,715	785,433	1,029,774	1,197,359	1,233,964	1,521,325	1,477,835	1,324,028	807,057	585,413	463,314
Qualifying Facilities Total	337,028,916	22,831,764	24,194,254	28,484,670	30,319,865	30,478,054	32,188,579	34,370,713	33,257,240	29,021,787	25,939,536	23,764,177	22,178,277
Mid-Columbia Contracts													
Douglas - Wells	-	-	-	-	-	-	-	-	-	-	-	-	-
Grant Reasonable	(962,821)	(80,235)	(80,235)	(80,235)	(80,235)	(80,235)	(80,235)	(80,235)	(80,235)	(80,235)	(80,235)	(80,235)	(80,235)
Grant Meaningful Priority	-	-	-	-	-	-	-	-	-	-	-	-	-
Grant Surplus	2,118,783	176,565	176,565	176,565	176,565	176,565	176,565	176,565	176,565	176,565	176,565	176,565	176,565
Grant - Priest Rapids	-	-	-	-	-	-	-	-	-	-	-	-	-
Mid-Columbia Contracts Total	1,155,962	96,330	96,330	96,330	96,330	96,330	96,330	96,330	96,330	96,330	96,330	96,330	96,330
Total Long Term Firm Purchases	537,699,239	42,244,511	40,854,187	46,983,440	47,231,388	46,535,127	47,757,029	49,011,571	47,588,446	44,162,087	42,770,303	41,457,607	41,103,542

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	4,500,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	-	-
PSCO FC III	-	-	-	-	-	-	-	-	-	-	-	-	-
Redding Exchange	-	-	-	-	-	-	-	-	-	-	-	-	-
SCL State Line	-	-	-	-	-	-	-	-	-	-	-	-	-
Tri-State Exchange	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Storage & Exchange	4,500,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	-	-
Short Term Firm Purchases													
COB	-	-	-	-	-	-	-	-	-	-	-	-	-
Colorado	-	-	-	-	-	-	-	-	-	-	-	-	-
Four Corners	-	-	-	-	-	-	-	-	-	-	-	-	-
Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-
Mead	-	-	-	-	-	-	-	-	-	-	-	-	-
Mid Columbia	-	-	-	-	-	-	-	-	-	-	-	-	-
Mona	-	-	-	-	-	-	-	-	-	-	-	-	-
NOB	-	-	-	-	-	-	-	-	-	-	-	-	-
Palo Verde	3,004,200	1,032,660	935,280	1,036,260	-	-	-	-	-	-	-	-	-
SP15	-	-	-	-	-	-	-	-	-	-	-	-	-
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	-	-	-	-	-	-	-	-	-	-	-	-
West Main	-	-	-	-	-	-	-	-	-	-	-	-	-
Wyoming	-	-	-	-	-	-	-	-	-	-	-	-	-
STF Electric Swaps	-	-	-	-	-	-	-	-	-	-	-	-	-
STF Index Trades	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Short Term Firm Purchases	3,004,200	1,032,660	935,280	1,036,260	-	-	-	-	-	-	-	-	-
System Balancing Purchases													
COB	18,327,930	344,916	1,277,311	1,439,699	1,801,104	1,259,874	1,604,442	3,093,938	1,863,191	1,302,006	1,114,137	730,769	2,496,541
Four Corners	18,590,868	2,370,197	3,726,633	1,544,526	855,982	1,021,844	508,104	1,586,860	829,898	799,957	1,357,344	1,525,723	2,463,800
Mead	7,026,681	631,350	803,091	331,058	299,611	344,281	538,745	656,162	393,759	572,714	880,575	705,268	870,066
Mid Columbia	98,143,809	6,385,253	1,867,297	611,939	4,781,086	11,786,536	11,435,541	21,272,861	23,033,585	6,765,946	3,245,920	1,890,875	5,066,971
Mona	10,081,472	1,462,180	793,236	176,526	493,196	894,267	543,673	587,512	522,751	1,136,276	1,290,293	1,093,932	1,087,630
NOB	16,774,770	143,126	144,710	667,356	1,296,705	74,870	42,883	3,620,443	4,561,609	2,443,358	41,141	237,346	3,501,225
Palo Verde	2,254,981	146,288	-	240,547	79,282	-	-	-	-	6,003	187,240	822,322	773,300
EIM Imports/Exports	(57,523,956)	(3,626,722)	(3,096,217)	(4,968,853)	(5,334,611)	(5,347,055)	(3,027,428)	(8,342,167)	(9,210,562)	(4,868,385)	(3,090,849)	(3,083,231)	(3,527,877)
Emergency Purchases	4,926,768	-	-	-	87,369	1,899,300	106,366	1,767,502	133,616	764,672	116,888	-	51,057
Total System Balancing Purchases	118,603,323	7,856,587	5,516,061	42,797	4,359,724	11,933,917	11,752,325	24,243,112	22,127,846	8,922,547	5,142,690	3,923,004	12,782,713
Total Purchased Power & Net Interc	663,806,761	51,583,758	47,755,528	48,512,497	52,041,113	58,919,044	59,959,354	73,704,682	70,166,293	53,534,634	48,362,993	45,380,611	53,886,256

Wheeling & U. of F. Expense													
Firm Wheeling	145,485,576	12,513,425	12,306,187	12,608,111	12,371,740	11,045,240	11,886,821	11,445,293	11,600,864	12,293,602	12,116,876	12,357,696	12,939,721
C&T EIM Admin fee	2,038,227	184,546	167,911	161,471	204,085	222,363	208,177	172,436	135,045	153,613	170,764	127,508	130,308
ST Firm & Non-Firm	77,740	10,959	2,155	1,242	409	41	1,233	4,497	3,058	1,789	5,346	19,973	27,038
Total Wheeling & U. of F. Expense	147,601,542	12,708,930	12,476,254	12,770,824	12,576,234	11,267,644	12,096,231	11,622,226	11,738,967	12,449,004	12,292,985	12,505,177	13,097,066
Coal Fuel Burn Expense													
Carbon	-	-	-	-	-	-	-	-	-	-	-	-	-
Cholla	-	-	-	-	-	-	-	-	-	-	-	-	-
Colstrip	14,529,149	1,963,617	1,575,990	-	549,760	35,331	1,518,435	1,667,963	1,765,305	1,586,533	1,155,284	1,148,887	1,562,045
Craig	19,084,507	2,158,895	1,846,200	1,888,587	1,555,805	739,280	1,512,088	1,741,851	2,008,203	1,864,463	1,826,131	882,588	1,060,415
Dave Johnston	61,444,601	5,939,740	5,633,774	5,225,282	4,319,134	4,834,485	4,608,699	5,055,834	5,549,418	4,995,895	5,540,888	4,366,474	5,374,978
Hayden	11,378,872	1,128,022	964,464	957,215	947,566	1,180,939	1,058,080	1,133,636	953,829	642,339	813,591	796,951	802,240
Hunter	103,544,708	12,917,766	10,078,241	8,720,522	3,989,666	5,850,144	6,319,866	9,171,472	9,435,626	8,235,664	6,523,349	10,363,412	11,938,980
Huntington	99,945,126	11,566,856	9,286,019	8,905,602	5,891,662	6,360,869	5,747,154	9,619,417	9,968,559	6,813,902	5,531,662	8,207,241	12,046,183
Jim Bridger	185,570,462	12,414,809	13,228,517	14,134,211	11,456,162	1,833,582	16,466,472	23,926,125	23,462,815	19,301,630	17,374,345	16,951,174	15,020,619
Naughton	24,416,678	2,631,756	2,080,702	1,826,281	1,571,672	1,490,832	1,722,123	2,475,291	2,396,853	2,074,380	2,043,087	1,723,152	2,380,549
Wyodak	23,501,147	1,736,640	1,683,138	2,296,146	2,067,380	2,498,564	1,915,498	2,360,936	2,201,436	2,115,597	1,953,159	1,565,443	1,107,211
Total Coal Fuel Burn Expense	543,415,251	52,458,100	46,377,044	43,953,846	32,348,808	24,824,026	40,868,414	57,152,526	57,742,043	47,630,402	42,761,497	46,005,323	51,293,221
Gas Fuel Burn Expense													
Chehalis	52,141,003	5,433,096	4,615,958	5,224,399	2,614,071	2,880,611	2,596,632	4,566,013	4,553,316	4,372,755	5,184,404	4,802,011	5,297,736
Currant Creek	51,557,946	4,443,697	3,053,967	3,095,487	3,230,204	3,076,260	4,316,414	5,738,641	4,351,648	4,713,092	5,089,156	5,599,294	4,850,087
Gadsby	6,593,595	448,766	155,979	165,281	294,644	329,044	530,961	985,527	958,872	709,890	485,871	540,446	988,314
Gadsby CT	3,691,885	259,178	90,182	86,484	120,498	111,374	175,709	545,142	457,895	367,771	440,076	332,182	705,393
Hermiston	23,497,733	2,272,730	2,255,283	2,448,181	1,280,774	693,291	1,158,592	2,110,407	2,142,757	2,207,596	2,318,486	2,296,571	2,313,064
Lake Side 1	66,543,261	6,417,594	5,214,579	4,532,828	4,792,919	4,022,040	5,406,628	6,802,780	6,878,460	6,203,876	5,402,239	5,681,119	5,188,200
Lake Side 2	64,554,164	6,610,613	5,340,728	4,622,857	4,699,601	4,065,594	4,954,173	5,531,555	5,798,751	5,515,316	5,932,724	5,312,496	6,169,755
Little Mountain	-	-	-	-	-	-	-	-	-	-	-	-	-
Naughton - Gas	23,456,234	2,403,614	1,817,360	1,644,654	1,054,038	2,496,664	2,252,282	2,302,997	1,902,238	1,526,592	1,664,247	1,490,045	2,901,503
Not Used	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Gas Fuel Burn	292,035,821	28,289,288	22,544,035	21,820,172	18,086,748	17,674,879	21,391,392	28,583,062	27,043,936	25,616,889	26,517,203	26,054,166	28,414,051
Gas Physical	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas Swaps	10,256,635	(1,241,705)	(637,980)	1,031,060	1,543,650	1,653,230	1,513,950	938,293	881,175	1,012,875	2,268,968	1,263,825	29,295
Clay Basin Gas Storage	2,126	(137,132)	(103,754)	4,566	52,242	52,242	52,242	52,242	52,242	52,242	52,242	(17,544)	(109,707)
Pipeline Reservation Fees	36,824,155	3,085,529	2,950,179	3,068,872	3,041,455	3,082,264	3,051,028	3,113,801	3,110,240	3,060,624	3,097,014	3,052,902	3,110,247
Total Gas Fuel Burn Expense	339,118,737	29,995,980	24,752,481	25,924,669	22,724,096	22,462,615	26,008,613	32,687,398	31,087,593	29,742,630	31,935,427	30,353,349	31,443,887
Other Generation													
Blundell	3,966,594	402,864	363,877	363,877	354,445	368,588	340,534	321,970	337,762	357,746	344,106	197,118	213,705
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	3,966,594	402,864	363,877	363,877	354,445	368,588	340,534	321,970	337,762	357,746	344,106	197,118	213,705
Net Power Cost	**1,445,454,540**	122,269,340	115,727,372	117,159,057	109,802,700	108,482,837	121,277,140	142,410,209	134,184,996	113,541,817	113,777,399	115,578,459	131,243,215
Net Power Cost/Net System Load	**23.87**	**22.97**	**24.83**	**24.12**	**24.03**	**22.72**	**23.98**	**24.47**	**24.03**	**23.33**	**23.93**	**23.67**	**24.28**

REDACTED
Docket No. UE 390
Exhibit PAC/103
Witness: David G. Webb

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED
Exhibit Accompanying Direct Testimony of David G. Webb

Update to Renewable Energy Production Tax Credits

April 2021

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

Docket No. UE 390
Exhibit PAC/104
Witness: David G. Webb

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of David G. Webb

Step Log Change

April 2021

2022 TAM Step Log						
ORTAM21						$ 1,400,378,595
	Description	Detail				Impact
	Routine Updates					25,021,354
Step 1	Market Capacity Update	Lowered market caps to the 4-year average				19,747,145
Step 2	Coal Plant Economic Cycling					355,018
		Minimum Operational Level (MW)				
		Units	2022 TAM	2021 TAM		
		Dave Johnston 3	100	170		
Step 3	Thermal Attributes updates	Dave Johnston 4	125	150		(47,570)
		Huntington 1	60	70		
		Huntington 2	60	80		
		Jim Bridger 4	100	133.3		
ORTAM22						$ 1,445,454,540

Docket No. UE 390
Exhibit PAC/105
Witness: David G. Webb

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of David G. Webb

March 1, 2021 Notice Letter

April 2021

PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
Portland, Oregon 97232

March 1, 2021

VIA ELECTRONIC MAIL

Attn: Parties to docket UE 375

RE: 2022 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 2022 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 GRID[1] model or to the logic of the GRID model by March 1st of the year of a stand-alone TAM filing."[2] The company is providing this notice to comply with the pre-filing review requirement and the methodology change notice requirement.

PacifiCorp provides notice of the following planned changes to the 2022 TAM:

- The coal plant must-run modeling methodology will be updated to be consistent with the settlement stipulation in last year's TAM, Docket No. UE 375.
- The Company's GRID model will base wholesale sales market caps on the four-year historical average of short-term firm, balancing and spot sales instead of the highest of the four most recently available relevant averages for each trading hub and each month, differentiated by on- and off-peak hours. This will be done in order to improve forecast accuracy and to address the Commission's concern noted on page 130 of Order 20-473 (Docket No. UE 374) regarding the overestimation of the Company's wholesale sales revenue.

As discussed with parties on February 25, 2021, due to a number of issues including the impacts of COVID-19, implementation of the new AURORA model will not be complete in time to be used for modeling net power costs in the 2022 TAM. As such, PacifiCorp will be using the GRID model for the 2022 TAM.

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

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[1] Generation and Regulation Initiative Decision Tools model.

[2] *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).

Sincerely,

Etta Lockey
Vice President, Regulation

cc: UE 375 Service List

Docket No. UE 390
Exhibit PAC/106
Witness: David G. Webb

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of David G. Webb

List of Expected or Known Contract Updates

April 2021

List of Known Items Expected to be Updated During the 2022 Oregon TAM

Sales and Purchases of Electricity and Natural Gas

1. New electricity sales and purchase contracts, physical and financial, including contracts with qualifying facilities.
2. Changes in contract terms of existing electricity sales and purchase and exchange contracts.
3. New natural gas sales and purchase contracts, physical and financial.
4. Changes in contract terms of existing natural gas sales and purchase contracts.
5. Contracts whose prices are linked to market indexes and inflation rates.
6. Sales contract with Black Hills Company for energy price.
7. Purchase contracts for generation and fixed costs from the Mid-Columbia projects.
8. Purchase expenses of PGE Cove based on PGE projection.
9. Election decision for Grant Meaningful Priority.

Transportation and Storage of Natural Gas

10. New pipeline and storage contracts for transporting natural gas from market to Company's generating facilities.
11. Changes in contract terms of existing pipeline and storage contracts.
12. Contracts whose prices are linked to market indexes and inflation rates.

Wheeling Expenses and Transmission

13. New transmission contracts to wheel power to serve the Company's load obligations.
14. Changes in contract terms of existing transmission contracts.
15. Wheeling expenses that are impacted by changes in third-parties' transmission tariff rates.
16. Contracts whose prices are linked to market indexes and inflation rates.

Other

17. Energy Imbalance Market benefit estimates, including import and export margins and volumes, as well as greenhouse gas benefits.

Coal Expense Update Items

The table below lists the coal and transportation contracts that may be affected by changes in volumes as well as changes to market indexes and inflation rates.

PacifiCorp
Coal and Transportation Contracts
Potential Updates in Reply Filing

Plant	Supplier/Mine	Captive		Fixed Price Coal Contracts		Variable Price Coal Contracts		Transportation Contracts	
		Volume	Price	Volume	Price	Volume	Price	Volume	Price
Bridger	Bridger Coal Company/Bridger	√	n/a						
	Lighthouse Resources/Black Butte			√	√				
	Union Pacific Railroad							√	√
Colstrip	Westmoreland/Rosebud					√	√		
Craig	Trapper Mining Inc/Trapper	√	n/a						
Hayden	Peabody/Twentymile			√	n/a				
	Union Pacific Railroad							√	√
Hunter	Bronco/Emery			√	n/a				
	Wolverine/Sufco, Skyline			√	n/a			√	√
Huntington	Wolverine/Sufco, Skyline			√	√				
	Utah Trucking							√	√
D Johnston	Unidentified PRB					√	√		
	Peabody/Caballo			n/a	n/a				
	Coal Creek/Arch			n/a	n/a				
	Peabody/NARM			n/a	n/a				
	BNSF Railway							√	√
Naughton	Westmoreland/Kemmerer					√	√		
Wyodak	Black Hills/Wyodak					√	√		

Note - The table lists the coal and transportation contracts that may be affected by changes in volumes or pricing due to changes in forward price curves, market indices and inflation rates

REDACTED
Docket No. UE 390
Exhibit PAC/107
Witness: David G. Webb

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED
Exhibit Accompanying Direct Testimony of David G. Webb

Economic Coal Cycling Study

April 2021

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REDACTED
Docket No. UE 390
Exhibit PAC/200
Witness: Dana M. Ralston

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED
Direct Testimony of Dana M. Ralston

April 2021

DIRECT TESTIMONY OF DANA M. RALSTON

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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 Dana M. Ralston. My business address is 1407 West North Temple, Suite 210, Salt Lake City, Utah 84116. My title is Senior Vice President of Thermal Generation and Mining.

I. QUALIFICATIONS

Q. Briefly describe your education and professional experience.

A. I have a Bachelor of Science Degree in Electrical Engineering from South Dakota State University. I was previously Vice President of Coal Generation and Mining from March 2015 to November 2017, and Vice President of Thermal Generation from January 2010 to March 2015. For 29 years before that, I held a number of positions of increasing responsibility within Berkshire Hathaway Energy's generation organizations, including plant manager at the Neal Energy Center generating complex. In my current role, I am responsible for operating and maintaining PacifiCorp's coal- and gas-fired generation fleet, coal fuel supply, and mining.

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, Washington, California, 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 2022 Transition Adjustment Mechanism (TAM). To demonstrate the reasonableness of these costs, my testimony:

- Details new coal supply agreements that PacifiCorp has entered into since the 2021 TAM, in accordance with the Commission's Order No. 20-392 in the 2021 TAM;[1]
- Provides history on the Huntington coal supply agreement and the minimum take provision in that contract to support the testimony of Mr. David G. Webb, in accordance with the Commission's Order No. 20-392, demonstrating that the Huntington plant's costs are reasonable compared to PacifiCorp's other plants and the market;
- Explains the primary reasons behind the significant reduction to the total-company coal-fuel expense—over $100 million—reflected in the 2022 TAM;[2] and
- Provides updated coal pricing and background on third-party coal contracts and affiliate-owned mines.

III. TESTIMONY FOR NEW COAL SUPPLY AGREEMENTS

Q. Has PacifiCorp entered into any new coal supply agreements since it filed reply testimony in the 2021 TAM?

A. Yes. PacifiCorp has entered into five new coal supply agreements: two related to the Dave Johnston plant, two related to the Hunter plant, and one related to the Craig plant. Consistent with the requirements of the stipulation approved in the 2021 TAM,

[1] *In the Matter of PacifiCorp, dba Pacific Power, 2021 Transition Adjustment Mechanism*, Docket No. UE 375, Order No. 20-392 (Oct. 30, 2020).
[2] Unless otherwise stated, all figures in my testimony are stated on a total-company basis.

my testimony provides additional information demonstrating the prudence of these contracts.[3]

Dave Johnston Coal Supply Agreements

Q. What are the new coal supply agreements for the Dave Johnston plant?

A. The Company executed two new coal supply agreements to purchase coal from Peabody Coal Sales, LLC. The two separate coal supply agreements are for coal deliveries from two separate mines, Caballo and North Antelope Rochelle (NARM). Both mines are located in the Powder River Basin, the largest coal producing region in the United States. Due to the abundance of coal in the Powder River Basin, along with the number of operating mines in this region, PacifiCorp is able to take advantage of very favorable coal market pricing that exists in the Powder River Basin.

Q. What is the term of each agreement?

A. [redacted] This term is consistent with PacifiCorp's approach of limiting its coal supply agreements to five years or less to maintain flexibility in fuel supply and generation planning.

Q. What is the Oregon exit date for the Dave Johnston plant?

A. The Commission approved an exit date of December 31, 2027 for Dave Johnston Units 1-4.

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[3] Order No. 20-392, Appendix A at 6, paragraph 17.

Q. What is the volume and pricing of the new coal supply agreements for the Dave Johnston plant?

A. In 2021, the Caballo mine will supply [redacted] at [redacted] and NARM will supply [redacted] at [redacted]. On a delivered cost basis, the cost of coal from these mines is very similar due to differences in coal heat content and haul distance to the plant. The Caballo coal cost is [redacted] on a delivered basis and the NARM coal cost is [redacted] on a delivered basis. Access to a small volume of NARM coal will provide the plant a third coal supply option in the event of coal supply disruption.

Q. How do the new agreements for the Dave Johnston plant compare with the expiring agreement?

A. The two new agreements are replacing one expiring agreement from Peabody's NARM. The expiring agreement was for [redacted] at a cost of [redacted]. The quality of the coal purchased under the new agreements is not materially different from the coal quality of the coal purchased under the prior agreement.

Q. With the new contracts, what are the coal supply arrangements for the Dave Johnston plant?

A. PacifiCorp has an existing contract with Arch Coal's Coal Creek mine to supply [redacted] and Peabody's Caballo mine for [redacted]. Under the new contracts, Peabody Energy's Caballo mine will supply [redacted], and NARM mine will supply [redacted] in 2021.

Q. Do these new agreements include a minimum take requirement?

A. Yes. Like the expiring agreement, the two new agreements for the Dave Johnston plant are take-or-pay agreements. PacifiCorp would not have been able to secure these coal supplies and favorable contract price without contract minimums. PacifiCorp was able to obtain added flexibility in the Caballo coal supply agreement, however, through a deferral option. PacifiCorp is required to purchase at least [redacted] PacifiCorp also has a minimum take of [redacted] coal supply agreement.

Q. How do the minimum take provisions of the coal supply agreements for the Dave Johnston plant compare with the most recent forecasted generation of the plant prior the execution of the coal agreement?

A. Including the new and current existing agreements at the Dave Johnston plant, there are [redacted] under contract for purchase in 2021. That amount can be further reduced to [redacted]. This is [redacted] of the total [redacted] 2022 TAM forecast. The negotiations for the new agreements were based upon a generation forecast that was part of the overall fueling budget for the Company. Before the two new agreements were signed, the Company completed an updated generation forecast for the plant. The budgeted and updated forecasted generation showed that the Dave Johnston plant would consume a greater tonnage volume than the coal under contract in 2021.

Q. Why are "minimum take" provisions generally required in contracts such as this?

A. Without a commitment by the customer to purchase a minimum amount of coal, the coal supplier does not have an assured market for the output of the mine; the contract is merely an option for the customer to purchase coal if desired while paying no cost for this option. No coal producer could afford to agree to such a contract as it would require a large investment of capital in reserves, development and equipment to be available to supply coal with no assurance that any coal would be purchased. 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. As a result, while some contracts may provide some flexibility for the customer to vary purchase requirements, nearly all coal supply contracts have a minimum volume commitment to purchase coal.

Q. How does PacifiCorp intend to obtain the coal supply not covered by contracts at the Dave Johnston plant?

A. Based on the projection that the Dave Johnston plant will consume approximately [redacted] in 2022, the plant has an open position. If needed, the Company will solicit coal supplies from Powder River Basin mines through a request for proposals (RFP) during 2021 to fill a reasonable portion of the open position, which may be adjusted according to market conditions. The relatively small size of the open position mitigates the risk to customers that coal supplies will be unavailable or costly. The Company has successfully used this fueling strategy for the Dave Johnston plant for several years.

Hunter Coal Supply Agreements

Q. What are the new coal supply agreements for the Hunter plant?

A. The Company executed two new coal supply agreements to purchase coal for the Hunter plant. The first agreement is with Bronco Utah Operations LLC (Bronco) and the second agreement is with Wolverine Fuels LLC (Wolverine).

Q. What is the term of each agreement?

A. The agreement with [redacted]. The agreement with Wolverine has a [redacted]. The new coal supply agreements for the Hunter plant are replacing the previous long-term agreement (20 years), and their much shorter-term demonstrates the Company's approach to limiting the duration of all new coal supply agreements. Both agreements are "delivered to plant" agreements, under which the suppliers pay the transportation costs.

Q. Does the Hunter plant have an Oregon exit date?

A. No. In docket UE 374, PacifiCorp initially proposed an exit date of December 31, 2029 to comply with the mandate contained in Senate Bill 1547 to remove coal-fired resources from rates by December 31, 2029. In response to Staff's opposition to setting this exit date for the Hunter plant in docket UE 374, PacifiCorp withdrew its request.

Q. Do these new agreements include a minimum take requirement?

A. Yes. Each of the new agreements for the Hunter plant has a minimum take requirement. The Company would not have been able to secure these coal supplies and favorable contract price—a reduction from the previous contract price—without a contract minimum.

Q. What is the volume and pricing of the new coal supply agreements for the Hunter plant?

A. In the 2021 test period, the Bronco agreement has a minimum take requirement of [redacted] at [redacted]. The Wolverine agreement has a minimum take requirement of [redacted] at [redacted]. The Wolverine agreement has a second-tier pricing level of [redacted] for all tons purchased above the annual minimum [redacted].

Q. How do the new agreements for the Hunter plant compare with the expiring agreement?

A. The two new agreements are replacing one expiring agreement with Wolverine. The expiring Wolverine agreement had a minimum take requirement of [redacted] at a cost of [redacted] in 2020. The quality of the coal purchased under the new agreements is not materially different from the quality of the coal purchased under the prior agreement.

Q. How do the minimum take provisions of the coal supply agreements for the Hunter plant compare with the most recent forecasted generation of the plant prior to the execution of the coal agreement?

A. When considering both of the new agreements at the Hunter plant, there is a combined minimum purchase requirement of [redacted] under contract for purchase in 2021, all of which is take or pay. The negotiations for the new agreements were based upon a generation forecast that was part of the overall fueling budget for the Company. Before the two new agreements were signed, the Company completed an updated generation forecast for the plant. The budgeted and updated forecasted generation showed that the Hunter plant would consume considerably more than the combined [redacted] minimum purchase requirement for coal under contract in 2021.

Craig Coal Supply Agreement

Q. What is the new coal supply agreement for PacifiCorp's share of Units 1 and 2 of the Craig plant?

A. In 2021, PacifiCorp's share of Units 1 and 2 at the Craig plant will be supplied by coal from the Trapper Mine under a new, five-year agreement replacing the previous, 11-year agreement. The Trapper Mine is an affiliate captive mine owned by PacifiCorp along with two of the five other owners of the Craig plant. PacifiCorp's share of the mine is 29.14 percent.

Q. Do Craig Units 1 and 2 have an Oregon exit date?

A. Yes. Craig Unit 1 has an exit date of December 31, 2025 and Craig Unit 2 has an exit date of December 31, 2026.

Q. Does the new agreement include a minimum take requirement?

A. Yes. The new agreement for the Craig plant does have an annual minimum take requirement. However, because of PacifiCorp's ownership interest in the Trapper Mine, the agreement has added flexibility and allows the parties under the agreement to modify the annual minimum requirement as needed based upon their mutual agreement.

Q. What is the volume and pricing of the new coal supply agreement for the Craig plant?

A. The agreement has a prescribed flexible annual tonnage nomination. PacifiCorp's share of the annual tonnage nomination has a range of [redacted]. The negotiations for the new agreement were based upon a generation forecast that was part of the overall fueling budget for the Company. The pricing under the coal supply agreement is based upon the Trapper mine's annual costs. These are derived from the mine's annual budgeting approval process, which supports specific detailed mine plans and agreed upon nominated tonnage volumes.

Q. How does the new coal supply agreement for the Craig plant compare with the expiring coal supply agreement?

A. The new Trapper agreement terms are virtually the same as the prior Trapper agreement, but the length of the contract is much shorter.

Q. What conclusion do you have regarding the new coal supply agreements?

A. PacifiCorp has negotiated new coal supply agreements that are prudent and in the best interests of our customers. The Company performed detailed analysis on the near-term needs based on the economic conditions known prior to contract execution. The new contracts ensure that customers will receive the lowest price coal available, that plants will be dispatched economically in the near-term, and that the Company retains as much flexibility as possible.

IV. HISTORY OF THE HUNTINGTON COAL SUPPLY AGREEMENT

Q. In the Commission's 2021 TAM Order, the Commission raised a concern about the minimum take levels at Huntington.[4] Can you please provide some history of the Huntington coal supply agreement?

A. Yes. As part of the closure of the Deer Creek Mine in 2014, the Company executed a long-term agreement with Bowie Resource Partners, LLC (Bowie), whereby Bowie agreed to supply the Company's coal requirements for Huntington from the close of the Deer Creek Mine through December 31, 2029. The coal supply agreement includes a "minimum take" provision generally requiring the Company to purchase a minimum specified amount of coal. As noted above, such minimum-take provisions are a fundamental component of most coal supply agreements and constitute the consideration required to obtain favorable pricing.

Q. Was approval of the long-term coal supply agreement an important component of PacifiCorp's proposed closure of the Deer Creek mine?

A. Yes. PacifiCorp obtained approval from its state commissions to close the Deer Creek Mine. Being able to point to a stable, reasonably-priced replacement coal supply was an important component of demonstrating that closure of the mine was in the public interest, especially given the limited coal market available to supply the Huntington plant. The Huntington coal supply agreement provided this certainty to customers and facilitated closure of the mine—resulting in lower costs and risks to customers.

[4] *In the Matter of PacifiCorp d/b/a Pacific Power, 2021 Transition Adjustment Mechanism*, Docket No. UE 375, Order No. 20-392 at 9-10 (Oct. 30, 2020).

Q. Did the Commission find that the closure of the Deer Creek Mine provided net benefits to customers?

A. Yes. While the Commission did not consider the Huntington coal supply agreement in its evaluation of net benefits, the Commission found substantial net benefits in the closure of the Deer Creek Mine, most notably from the reduced annual pension trust contribution.[5]

V. OVERVIEW OF PACIFICORP'S COAL SUPPLIES

Q. How does PacifiCorp plan to meet fuel supplies for its coal plants in 2022?

A. PacifiCorp employs a diversified coal supply strategy, as reflected below in Confidential Table 1. PacifiCorp will supply 81.9 percent of its 2022 coal requirements with third-party coal supplies and 18.1 percent with coal from its captive affiliate mines. Within the third party contracts: (1) 56.4 percent of the total coal requirement will be supplied from fixed-price contracts; (2) 9.6 percent will be supplied under variable-priced contracts that increase or decrease based on changes to producer and consumer price indices; and (3) 15.9 percent of the total coal requirement will be supplied from contracts for the Jim Bridger, Naughton and Dave Johnston plants to be negotiated in 2021 and will be discussed later in my testimony.

[5] *In the Matter of PacifiCorp, dba Pacific Power, Application for Approval of Deer Creek Mine Transaction*, Docket No. UM 1712, Order No. 15-161 (May 27, 2015).

Confidential Table 1: Coal Source Deliveries

2022 Company/Mine	Plant	Price Reopener	New Contract	MMBtus (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]	18.1%
Fixed Price Contracts				[redacted]	[redacted]	
Lighthouse Resources/Black Butte	Jim Bridger			[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]	
Peabody/Caballo	Dave Johnston			[redacted]	[redacted]	
Arch/Coal Creek	Dave Johnston			[redacted]	[redacted]	
Subtotal Fixed Price Contracts				[redacted]	[redacted]	56.4%
Variable Price Contracts				[redacted]	[redacted]	
Westmoreland/Rosebud	Colstrip			[redacted]	[redacted]	
Black Hills/Wyodak	Wyodak			[redacted]	[redacted]	
Subtotal Variable Price Contracts				[redacted]	[redacted]	9.6%
Future Contracts				[redacted]	[redacted]	
Lighthouse Resources/Black Butte	Jim Bridger			[redacted]	[redacted]	
Westmoreland/Kemmerer	Naughton			[redacted]	[redacted]	
Unspecified PRB Mines	Dave Johnston			[redacted]	[redacted]	
Total Other				[redacted]	[redacted]	15.9%
Total Coal Supplies				[redacted]	[redacted]	100%

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

Q. Has total coal-fuel expense in the 2022 TAM decreased from the level reflected in PacifiCorp's 2021 TAM?

A. Yes. As stated in the testimony of Mr. Webb, total coal-fuel expense has decreased by $114 million in the 2022 TAM. This decrease is a result of a $114.2 million volume reduction in coal-fired generation, partially offset by approximately $0.2 million in higher coal prices. These variances are shown in Confidential Table 2 below.

Confidential Table 2: Coal Fuel Variance - 2022 TAM vs. 2021 TAM

Plant	Contract		Millions ($)
Price Variance			
Affiliate Mines		[redacted]	
Jim Bridger	Bridger Coal Company		
Craig	Trapper Coal		
Subtotal Affiliate Mines			
Third-Party Contracts			
Naughton	Kemmerer Coal		
Wyodak	Wyodak Coal		
Dave Johnston	Powder River Basin Coal		
Dave Johnston	BNSF Rail		
Jim Bridger	Black Butte Coal		
Jim Bridger	UPRR Rail		
Hunter	Wolverine Coal		
Huntington	Wolverine and Castle Valley Coal		
Colstrip	Rosebud Coal		
Hayden	Twentymile Coal and UPRR Rail		
Subtotal Third-party Contracts			
Total Price Variance			$ 0.2
Volume Variance			
Jim Bridger			
Huntington			
Hunter			
Naughton			
Other Plants			
Total Volume Variance			$ (114.2)
Total Coal Fuel Variance - Increase/(Decrease)			$ (114.0)

VI. JIM BRIDGER FUEL SUPPLY

Bridger Coal Company

Q. Please describe the change in Bridger Coal Company (BCC) costs in the 2022 TAM.

A. BCC costs in the 2022 TAM are forecast to be [redacted] lower than the 2021

TAM. The cost for the base mine plan deliveries of [redacted] increases by [redacted], from [redacted] in the 2021 TAM to [redacted] in the 2022 TAM as shown in Confidential Table 3. The 2022 TAM includes a base tonnage delivery of [redacted] which is [redacted] less than in the 2021 TAM. In the 2022 TAM the mine is projected to deliver [redacted] than in the 2021 TAM. The increased supplemental coal delivery results in a favorable price variance of [redacted].

Confidential Table 3: Jim Bridger Plant Coal Deliveries

	2022 TAM			2021 TAM			Variance			Price
	Tons	Dollars	$ / Ton	Tons	Dollars	$ / Ton	Tons	Dollars	$ / Ton	Variance
Bridger Coal Deliveries										
Bridger Base Mine Plan	[redacted]									
Supplemental Coal										
Total Bridger Coal										
Black Butte Deliveries										
Total Jim Bridger Plant										

Q. Please summarize why base mine costs decrease in the 2022 TAM.

A. The change is primarily due to delivering [redacted] less base tons at a decreased cost of [redacted], a decrease of [redacted] for labor and benefits, a decrease of [redacted] for materials and supplies, and a decrease of [redacted] for depreciation, depletion and amortization. These are partially offset by an increase of [redacted] for coal inventory, [redacted] for final reclamation contributions, [redacted] increase in the final reclamation credit, [redacted] increase due to a decreased heat content of the delivered coal, and [redacted] for other miscellaneous costs.

Q. Please explain the operational difference at BCC between 2022 TAM and the 2021 TAM.

A. In the 2021 TAM, BCC had operations from both the underground and surface mines with the primary source of coal coming from the underground mine. For most of the 2022 TAM, the underground mine will no longer be in operation. The surface mine will be producing and delivering the majority of the coal with some coal from the underground mine being delivered from the coal inventory at the mine.

Q. Please explain why the base tonnage volume decreased in the 2022 TAM.

A. BCC delivered [redacted] fewer base tons due a reduction in coal consumption requirements at the Jim Bridger plant. This decreased coal costs by [redacted] in the 2022 TAM.

Q. Please explain why labor and benefits, materials and supplies, and depreciation, depletion and amortization decreased in the 2022 TAM.

A. The decrease of [redacted] for labor and benefits, [redacted] for material and supplies, and [redacted] for depreciation, depletion and amortization is primarily due to the closure of the underground mine and increased deliveries from the surface mine.

Q. Why did coal inventory costs increase by [redacted] in the 2022 TAM?

A. The primary reason for the increase of [redacted] for coal inventory costs is due to the mine shipping more coal than it produces in 2022.

Q. Please explain why final reclamation contributions increased by [redacted] in the 2022 TAM.

A. The contributions to the final reclamation increased by [redacted], or [redacted].

The increase is primarily due to the decreased coal delivered in the base plan. The total final reclamation contributions decreased by [redacted] due to reductions in volume.

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

A. The 2021 TAM assumed the mine would complete [redacted] of final reclamation. The 2022 TAM assumed the mine would complete [redacted] of final reclamation. The decrease in the reclamation of [redacted] increases the final reclamation credit by [redacted] in the 2022 TAM.

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

A. The average British thermal unit per pound (Btu/lb) content assumed delivered in the 2021 TAM was [redacted]. The average Btu/lb content of coal projected to be delivered in the 2022 TAM is [redacted]. The projected decrease in the heat content of [redacted] results in an unfavorable cost increase of [redacted].

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

A. Cost components included in the miscellaneous category with slight cost increases include royalties and taxes, outside services, and deferred longwall amortization.

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.[6] In this filing, does PacifiCorp adjust the price of coal from BCC consistent with this order?

A. Yes. In the 2022 TAM, the Company reduces BCC costs by approximately [redacted] to reflect removal of management overtime and 50 percent of annual incentive plan awards.

Jim Bridger Third-Party Coal Supply

Q. What is the expected change in third-party coal prices for the Jim Bridger plant in the 2022 TAM?

A. Delivered costs for the [redacted] of Black Butte coal increased from [redacted] in the 2021 TAM to [redacted] in the 2022 TAM, or [redacted] overall. In 2020, PacifiCorp deferred [redacted] to be purchased in 2021 to 2022. The price of the deferred tons is [redacted]. The remaining [redacted] are still to be negotiated as part of a new coal supply agreement using an estimated price of [redacted]. The coal price increase is approximately [redacted], or [redacted]. The Union Pacific Railroad agreement is forecast to increase by [redacted] in delivered costs.

VII. THIRD-PARTY COAL CONTRACTS

Q. Please discuss the change in overall third-party coal-supply costs in the 2021 TAM.

A. PacifiCorp expects a price variance net increase of the third-party coal-supply costs of

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[6] *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).

[redacted], as shown in Confidential Table 2 above. The details by plant are described below.

Coal Supply Agreements for the Wyoming Plants

Naughton

Q. Please describe the coal supply arrangement for the Naughton plant in 2022.

A. The Naughton plant is supplied by the adjacent Kemmerer mine under a long-term coal supply agreement through 2021. Negotiations on a new coal supply agreement will begin in earnest later this year.

Q. Please describe the Naughton plant's coal cost change from the 2021 TAM.

A. Total delivered coal cost at Naughton decreased from [redacted] in the 2021 TAM to [redacted] in the 2022 TAM, or [redacted] overall. The pricing for 2022 is an estimate based on preliminary discussions with the Kemmerer mine. The primary reason for the decrease is that in 2021 the costs included [redacted] of environmental shortfall payments that are no longer included in the 2022 coal costs, which is partially offset by an increase to coal costs.

Wyodak

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

A. Delivered coal cost increased from [redacted] in the 2021 TAM to [redacted] in the 2022 TAM, or [redacted] overall. The cost increase is primarily the result of escalation in diesel fuel and other contract indices.

Dave Johnston

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

A. Dave Johnston plant delivered coal cost increased by [redacted] compared to the

2021 TAM, or [redacted]. The increase is due to an increase in coal costs of [redacted], an increase of rail cost of approximately [redacted] for increases to rail indices and diesel fuel costs, and an increase of [redacted] for the expiration of the refined coal credits PacifiCorp was receiving.

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

A. As explained above, the Company has only contracted for approximately [redacted] of Dave Johnston's coal supply and will rely on an RFP to fill this open position as needed. The coal price applied to this open position reflects the average 2022 forward price for Powder River Basin 8400 Btu coal of [redacted], as published by Coal Daily. The 2022 price is [redacted] lower than the 2021 Powder River Basin 8400 Btu price of [redacted] that was used for the open position in the 2021 TAM.

Coal Supply Agreements for the Utah Plants

Hunter

Q. Please describe the change in coal costs at the Hunter plant in the 2022 TAM.

A. Under the new coal supply agreements described above, coal prices have increased [redacted], from [redacted] in the 2021 TAM (which included prices based on an estimate of the price under the new coal supply agreements) to [redacted] in the 2022 TAM [redacted] overall). Of the [redacted] increase, [redacted] is related to the expiration of the refined coal credit PacifiCorp was receiving. The coal prices for the Bronco agreement have increased [redacted], from [redacted] in the 2021 TAM to [redacted] in the 2022 TAM [redacted]. This increase is due to the annual increase in the coal contract and a reduction of tier 2 tons being purchased. The increases are partially offset by a decrease resulting from the price of the new Wolverine agreement as compared to the spot coal purchased in the 2021 TAM. In the 2021 TAM, the spot coal purchases were at [redacted]. The coal purchases from Wolverine in the 2022 TAM are at [redacted] decrease).

Huntington

Q. Please describe the coal supply arrangement for the Huntington plant in 2022.

A. The coal supply to the Huntington plant is provided under a requirements contract with Wolverine. 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 2022 TAM?

A. For the Huntington plant, delivered coal prices increased from [redacted] in the 2021 TAM to [redacted] in the 2022 TAM, an overall increase of [redacted] or [redacted] for the weighted average price under the Wolverine contract. The Wolverine contract price is higher in 2022 primarily because of contractual increase in the contract price, partially offset by an increase in tier 2 coal deliveries and a small decrease in the transportation cost escalator.

Q. Does the 2022 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 2021 General Rate Case (docket UE 374).

Coal Supply Agreements for the Jointly-Owned Plants

Craig

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

A. As described above, in 2022, the Craig plant will be supplied under a new agreement with the Trapper mine, which is an affiliate captive mine owned by three of the five Craig plant owners. Trapper mine costs have decreased [redacted], from [redacted] in the 2021 TAM to [redacted] in the 2022 TAM, a [redacted] overall price decrease. The price decrease is primarily due to overall mining costs at the Trapper mine. Deliveries from Trapper mine have increased [redacted] from [redacted] in the 2021 TAM to [redacted] in the 2022 TAM.

Hayden

Q. Please describe the change in Hayden plant's coal cost in the 2022 TAM.

A. Delivered coal prices increased [redacted], from [redacted] in the 2021 TAM to [redacted] in the 2022 TAM, an increase of [redacted]. Under the terms of the January 1, 2018 reopener, the coal prices escalate on a fixed annual schedule from 2018 through 2022 and are no longer subject to market indices.

Colstrip

Q. Please describe the change in coal cost at the Colstrip plant in the 2022 TAM.

A. Delivered coal prices increased [redacted], from [redacted] in the 2021 TAM to [redacted] in the 2022 TAM, an increase of [redacted]. PacifiCorp developed the 2022 TAM costs for the Colstrip plant based on the coal supply agreement that was signed December 5, 2019. The increase in costs are primarily due to an increase in the contract indices and to a lower volume of tier 2 coal being purchased.

VIII. SUMMARY

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

A. Customers have significantly benefited from PacifiCorp's diversified fueling strategy, which relies upon fixed-price contracts, index-priced contracts, and affiliate-owned mines to meet the fuel needs of its coal-fired generating plants. Several factors have contributed to an overall decrease in coal-fuel expense in this filing, primarily reduced coal volumes, as shown in Confidential Table 2 above. PacifiCorp's fueling strategy has resulted in long-term, stable, low-cost coal supplies for its customers. PacifiCorp has been able to reduce its coal generation and coal expense by approximately $114 million total company with a minimal increase in coal unit prices. This is due to PacifiCorp's continued efforts to work with its coal suppliers and mines for the benefit of our customers.

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. UE 390
Exhibit PAC/300
Witness: Judith M. Ridenour

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Direct Testimony of Judith M. Ridenour

April 2021

DIRECT TESTIMONY OF JUDITH M. RIDENOUR

TABLE OF CONTENTS

ATTACHED EXHIBITS

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.

I. QUALIFICATIONS

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 2022 Transition Adjustment Mechanism (TAM) to recover the Oregon-allocated forecast net power costs (NPC) identified by Mr. David G. Webb. 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 No. 09-274,[1] the test period for the TAM is the year during which the Schedule 201 rates will be effective, which is the 12 months ending December 31, 2022.

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

A. PacifiCorp allocated forecast NPC to the customer classes based on the present spread of NPC revenue. This is consistent with the TAM Guidelines and the generation allocation in the Company's last general rate case, approved by the Public Utility Commission of Oregon in Order No. 20-473,[2] updated for the change in load.

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

A. Yes. Exhibit PAC/301 shows present Schedule 201 rates and revenues, and the associated rate spread and revenue targets for each rate schedule based on the Oregon-allocated forecast NPC, including the adjustment for non-NPC Energy Imbalance Market costs and the updated amount for Production Tax Credits, identified by Mr. Webb. The final columns in the exhibit show the proposed

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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).
[2] *In the Matter of PacifiCorp, d/b/a Pacific Power, Request for a General Rate Revision,* Docket No. UE 374, Order No. 20-473 (Dec. 18, 2020).

Schedule 201 rates and revenues. As explained by Mr. Webb, forecast NPC is subject to updates throughout this proceeding.

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 use the same rate blocks and relationships between rate blocks as the existing Schedule 201 rates.

Q. Please describe Exhibit PAC/302.

A. Exhibit PAC/302 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 0.1 percent, on a net basis. The rate change varies by customer type. Page one of Exhibit PAC/303 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 Energy Conservation Charge (Schedule 297).

Q. Did you prepare an exhibit that shows the impact on customer bills as a result of the proposed changes to Schedule 201?

A. Yes. Exhibit PAC/303, 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 Energy Conservation Charge (Schedule 297).

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

A. The estimated monthly impact to the average single-family residential customer using 900 kilowatt-hours per month is a bill increase of $0.08.

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. UE 390
Exhibit PAC/301
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

April 2021

PACIFIC POWER
STATE OF OREGON
Schedule 201 - Net Power Costs - Cost-Based Supply Service
Proposed Rate and Revenue Adjustments
Forecast 12 Months Ended December 31, 2022

Rate Schedule	Forecast Energy	Present Schedule 201 Rates	Present Schedule 201 Revenues	Generation Rate Spread	Target Revenues	Proposed Schedule 201 Rates	Proposed Schedule 201 Revenues
Schedule 4, Residential							
First Block kWh (0-1,000)	4,264,819,723	2.166 ¢	$92,375,995	30.5379%	$92,746,024	2.175 ¢	$92,759,829
Second Block kWh (> 1,000)	1,379,189,185	2.906 ¢	$40,079,238	13.2495%	$40,239,783	2.918 ¢	$40,244,740
	5,644,008,908		$132,455,233		$132,985,807		$133,004,569
Schedule 6 TOU Pilot, untiered, per kWh		*2.347 ¢*				*2.357 ¢*	
Employee Discount							
First Block kWh (0-1,000)	10,066,154	2.166	$218,033			2.175 ¢	$218,939
Second Block kWh (> 1,000)	4,176,979	2.906	$121,383			2.918 ¢	$121,884
	14,243,133		$339,416				$340,823
Discount			-$84,854		-$85,206		-$85,206
Schedule 23, Small General Service							
Secondary Voltage							
1st 3,000 kWh, per kWh	888,416,746	2.361 ¢	$20,975,519	6.9341%	$21,059,540	2.370 ¢	$21,055,477
All additional kWh, per kWh	256,294,607	1.750 ¢	$4,485,156	1.4827%	$4,503,122	1.757 ¢	$4,503,096
	1,144,711,353		$25,460,675		$25,562,662		$25,558,573
Primary Voltage							
1st 3,000 kWh, per kWh	1,343,630	2.288 ¢	$30,742	0.0102%	$30,865	2.297 ¢	$30,863
All additional kWh, per kWh	753,124	1.697 ¢	$12,781	0.0042%	$12,832	1.704 ¢	$12,833
	2,096,754		$43,523		$43,697		$43,696
Schedule 28, General Service 31-200kW							
Secondary Voltage							
All kWh, per kWh	2,002,478,473	2.243 ¢	$44,915,592	14.8483%	$45,095,510	2.251 ¢	$45,075,790
	2,002,478,473		$44,915,592		$45,095,510		$45,075,790
Primary Voltage							
All kWh, per kWh	25,195,129	2.221 ¢	$559,584	0.1850%	$561,826	2.230 ¢	$561,851
	25,195,129		$559,584		$561,826		$561,851
Schedule 29 TOU Pilot, untiered, per kWh		*2.824 ¢*				*2.834 ¢*	
Schedule 30, General Service 201-999kW							
Secondary Voltage							
All kWh, per kWh	1,245,499,987	2.187 ¢	$27,239,085	9.0048%	$27,348,196	2.196 ¢	$27,351,180
	1,245,499,987		$27,239,085		$27,348,196		$27,351,180
Primary Voltage							
All kWh, per kWh	95,953,984	2.222 ¢	$2,132,098	0.7048%	$2,140,639	2.232 ¢	$2,141,693
	95,953,984		$2,132,098		$2,140,639		$2,141,693
Schedule 41, Agricultural Pumping Service							
Secondary Voltage							
All kWh, per kWh	219,207,992	2.121 ¢	$4,649,402	1.5370%	$4,668,026	2.129 ¢	$4,666,938
	219,207,992		$4,649,402		$4,668,026		$4,666,938
Primary Voltage							
All kWh, per kWh	39,038	2.088 ¢	$815	0.0003%	$818	2.096 ¢	$818
	39,038		$815		$818		$818
Schedule 47, Large General Service, Partial Requirements 1,000kW and over							
Primary Voltage							
On-Peak, per on-peak kWh	8,372,425	2.551 ¢	$213,581			2.561 ¢	$214,418
Off-Peak, per off-peak kWh	13,528,339	1.812 ¢	$245,134			1.819 ¢	$246,080
	21,900,764		$458,715		$460,498		$460,498
Transmission Voltage							
On-Peak, per on-peak kWh	4,706,357	2.427 ¢	$114,223			2.437 ¢	$114,694
Off-Peak, per off-peak kWh	7,604,630	1.688 ¢	$128,366			1.695 ¢	$128,898
	12,310,987		$242,589		$243,592		$243,592

PACIFIC POWER
STATE OF OREGON
Schedule 201 - Net Power Costs - Cost-Based Supply Service
Proposed Rate and Revenue Adjustments
Forecast 12 Months Ended December 31, 2022

Rate Schedule	Forecast Energy	Present Schedule 201 Rates	Present Schedule 201 Revenues	Generation Rate Spread	Target 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	205,378,561	2.644 ¢	$5,430,209	1.7951%	$5,451,961	2.655 ¢	$5,452,801
Off-Peak, per off-peak kWh	331,853,576	1.905 ¢	$6,321,811	2.0899%	$6,347,134	1.913 ¢	$6,348,359
	537,232,137		$11,752,020		$11,799,095		$11,801,160
Primary Voltage							
On-Peak, per on-peak kWh	545,111,465	2.551 ¢	$13,905,793	4.5970%	$13,961,495	2.561 ¢	$13,960,305
Off-Peak, per off-peak kWh	880,802,446	1.812 ¢	$15,960,140	5.2761%	$16,024,071	1.819 ¢	$16,021,796
	1,425,913,911		$29,865,933		$29,985,566		$29,982,101
Transmission Voltage							
On-Peak, per on-peak kWh	441,125,339	2.427 ¢	$10,706,112	3.5393%	$10,748,997	2.437 ¢	$10,750,225
Off-Peak, per off-peak kWh	731,311,245	1.688 ¢	$12,344,534	4.0809%	$12,393,982	1.695 ¢	$12,395,726
	1,172,436,584		$23,050,646		$23,142,980		$23,145,951
Schedule 15, Outdoor Area Lighting Service							
Secondary Voltage							
All kWh, per kWh	8,513,794	0.890 ¢	$75,626	0.0250%	$75,929	0.897 ¢	$76,578
	8,513,794		$75,626				$76,578
Schedule 51, Street Lighting Service, Company-Owned System							
Secondary Voltage							
All kWh, per kWh	20,527,632	0.890 ¢	$184,439	0.0610%	$185,178	0.897 ¢	$184,439
	20,527,632		$184,439				$184,439
Schedule 53, Street Lighting Service, Consumer-Owned System							
Secondary Voltage							
All kWh, per kWh	11,099,592	0.890 ¢	$98,786	0.0327%	$99,182	0.897 ¢	$99,563
	11,099,592		$98,786				$99,563
Schedule 54, Recreational Field Lighting							
Secondary Voltage							
All kWh, per kWh	1,422,564	0.890 ¢	$12,661	0.0042%	$12,712	0.897 ¢	$12,760
	1,422,564		$12,661				$12,760
Total before Employee Discount			**$303,197,422**	**100.0000%**	**$304,411,912**		**$304,411,750**
Employee Discount			-$84,854		-$85,206		-$85,206
TOTAL	**13,590,549,583**		**$303,112,568**		**$304,326,706**		**$304,326,544**
						Change	**$1,213,976**
Schedule 47 Unscheduled kWh	1,596,106						
Total Forecast kWH	13,592,145,689						

Docket No. UE 390
Exhibit PAC/302
Witness: Judith M. Ridenour

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Judith M. Ridenour

Proposed Tariff Schedule

April 2021

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**	
4	Per kWh	0-1000 kWh	2.175¢			(I)
		> 1000 kWh	2.918¢			(I)
5	Per kWh	0-1000 kWh	2.175¢			(I)
		> 1000 kWh	2.918¢			(I)

For Schedules 4 and 5, the kilowatt-hour blocks listed above are based on an average month of approximately 30.42 days. Residential kilowatt-hour blocks shall be prorated to the nearest whole kilowatt-hour based upon the number of whole days in the billing period (see Rule 10 for details).

			Secondary	**Primary**	**Transmission**	
6	Per kWh	All kWh	2.357¢			(I)
	plus	per On-Peak kWh	14.270¢			
	plus	per Off-Peak kWh (credit)	-3.790¢			

For Schedule 6, On-Peak hours are from 5 p.m. to 9 p.m., all days. Off-Peak hours are all remaining hours

			Secondary	**Primary**	**Transmission**	
23	First 3,000 kWh, per kWh		2.370¢	2.297¢		(I)
	All additional kWh, per kWh		1.757¢	1.704¢		(I)
28	All kWh, per kWh		2.251¢	2.230¢		(I)

(continued)

Monthly Billing (continued)

Delivery Service Schedule No.		Secondary	Delivery Voltage Primary	Transmission	
29	All kWh, per kWh	2.834¢	2.834¢		(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	2.196¢	2.232¢		(I)
41	All kWh, per kWh	2.129¢	2.096¢		(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	2.655¢	2.561¢	2.437¢	(I)
	Per kWh, Off-Peak	1.913¢	1.819¢	1.695¢	(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	$0.68	(I)
	Level 2	5,001-12,000	34	$1.21	(I)
	Level 3	12,001+	57	$2.03	(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
	Level 2	3,501-5,500	15	$0.46
	Level 3	5,501-8,000	25	$0.76
	Level 4	8,001-12,000	34	$1.04
	Level 5	12,001-15,500	44	$1.34
	Level 6	15,501+	57	$1.74

	Types of Luminaire	Nominal rating	Watts	Monthly kWh	Rate Per Luminaire	
53	High Pressure Sodium	5,800	70	31	$0.28	
	High Pressure Sodium	9,500	100	44	$0.39	
	High Pressure Sodium	16,000	150	64	$0.57	
	High Pressure Sodium	22,000	200	85	$0.76	
	High Pressure Sodium	27,500	250	115	$1.03	(I)
	High Pressure Sodium	50,000	400	176	$1.58	(I)
	Metal Halide	9,000	100	39	$0.35	
	Metal Halide	12,000	175	68	$0.61	
	Metal Halide	19,500	250	94	$0.84	
	Metal Halide	32,000	400	149	$1.34	(I)
	Metal Halide	107,800	1,000	354	$3.18	(I)
	Non-Listed Luminaire, per kWh				0.897¢	(I)

54 Per kWh 0.897¢ (I)

(continued)

Docket No. UE 390
Exhibit PAC/303
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

April 2021

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, 2022

					Present Revenues ($000)			Proposed Revenues ($000)			Change				
											Base Rates		Net Rates		
Line No.	Description	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)	
							(5) + (6)			(8) + (9)	(8) - (5)	(11)/(5)	(10) - (7)	(13)/(7)	
	Residential														
1	Residential	4	530,213	5,644,009	$597,517	$8,514	$606,031	$598,066	$8,514	$606,580	$549	0.1%	$549	0.1%	1
2	**Total Residential**		530,213	5,644,009	$597,517	$8,514	$606,031	$598,066	$8,514	$606,580	$549	0.1%	$549	0.1%	2
	Commercial & Industrial														
3	Gen. Svc. < 31 kW	23	84,307	1,146,808	$124,771	$753	$125,524	$124,869	$753	$125,622	$98	0.1%	$98	0.1%	3
4	Gen. Svc. 31 - 200 kW	28	10,611	2,027,674	$164,049	$9,041	$173,089	$164,211	$9,041	$173,252	$162	0.1%	$162	0.1%	4
5	Gen. Svc. 201 - 999 kW	30	881	1,341,454	$97,741	$4,738	$102,479	$97,863	$4,738	$102,601	$122	0.1%	$122	0.1%	5
6	Large General Service >= 1,000 kW	48	198	3,135,583	$199,120	($13,641)	$185,479	$199,381	($13,641)	$185,740	$261	0.1%	$261	0.1%	6
7	Partial Req. Svc. >= 1,000 kW	47	6	35,808	$4,154	($153)	$4,001	$4,157	($153)	$4,003	$3	0.1%	$3	0.1%	7
8	Dist. Only Lg Gen Svc >= 1,000 kW	848	1	0	$1,681	$9	$1,691	$1,681	$9	$1,691	$0	0.0%	$0	0.0%	8
9	Agricultural Pumping Service	41	7,964	219,247	$24,868	($3,073)	$21,796	$24,886	($3,073)	$21,813	$18	0.1%	$18	0.1%	9
10	**Total Commercial & Industrial**		103,968	7,906,573	$616,384	($2,326)	$614,058	$617,047	($2,326)	$614,722	$663	0.1%	$663	0.1%	10
	Lighting														
11	Outdoor Area Lighting Service	15	5,934	8,514	$931	$303	$1,235	$932	$303	$1,236	$1	0.1%	$1	0.1%	11
12	Street Lighting Service Comp. Owned	51	1,106	20,528	$2,710	$950	$3,660	$2,710	$950	$3,660	$0	0.0%	$0	0.0%	12
13	Street Lighting Service Cust. Owned	53	312	11,100	$640	$201	$841	$641	$201	$842	$1	0.1%	$1	0.1%	13
14	Recreational Field Lighting	54	103	1,423	$100	$33	$133	$100	$33	$133	$0	0.1%	$0	0.1%	14
15	**Total Public Street Lighting**		7,455	41,564	$4,381	$1,488	$5,869	$4,383	$1,488	$5,871	$2	0.0%	$2	0.0%	15
16	**Subtotal**		641,636	13,592,146	$1,218,282	$7,676	$1,225,958	$1,219,497	$7,676	$1,227,172	$1,214	0.1%	$1,214	0.1%	16
17	Emplolyee Discount		*1,061*	*14,243*	($372)	($5)	($377)	($372)	($5)	($378)	($0)		($0)		17
18	AGA Revenue				$0		$0	$0		$0	$0		$0		18
19	COOC Amortization				$1,727		$1,727	$1,727		$1,727	$0		$0		19
20	**Total Sales with AGA**		641,636	13,592,146	$1,219,638	$7,670	$1,227,308	$1,220,852	$7,670	$1,228,522	$1,214	0.1%	$1,214	0.1%	20

[1] Excludes effects of the Low Income Bill Payment Assistance Charge (Sch. 91), BPA Credit (Sch. 98), Public Purpose Charge (Sch. 290) and Energy Conservation Charge (Sch. 297).

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

Pacific Power
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	$19.62	$19.63	$0.01	0.05%
200	$28.71	$28.73	$0.02	0.07%
300	$37.81	$37.84	$0.03	0.08%
400	$46.90	$46.93	$0.03	0.06%
500	$56.00	$56.05	$0.05	0.09%
600	$65.10	$65.16	$0.06	0.09%
700	$74.19	$74.25	$0.06	0.08%
800	$83.29	$83.36	$0.07	0.08%
900	**$92.38**	**$92.46**	**$0.08**	**0.09%**
1,000	*$101.48*	*$101.57*	*$0.09*	*0.09%*
1,100	$112.75	$112.85	$0.10	0.09%
1,200	$124.00	$124.13	$0.13	0.10%
1,300	$135.27	$135.41	$0.14	0.10%
1,400	$146.53	$146.68	$0.15	0.10%
1,500	$157.81	$157.96	$0.15	0.10%
1,600	$169.07	$169.23	$0.16	0.09%
2,000	$214.12	$214.34	$0.22	0.10%
3,000	$326.77	$327.11	$0.34	0.10%
4,000	$439.41	$439.87	$0.46	0.10%
5,000	$552.05	$552.64	$0.59	0.11%

* Net rate including Schedules 91, 98, 290 and 297.

Note: Assumed average billing cycle length of 30.42 days.

Pacific Power
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	$18.06	$18.07	$0.01	0.06%
200	$27.15	$27.18	$0.03	0.11%
300	$36.26	$36.29	$0.03	0.08%
400	$45.35	$45.38	$0.03	0.07%
500	$54.45	$54.50	$0.05	0.09%
600	*$63.55*	*$63.61*	*$0.06*	*0.09%*
700	$72.64	$72.70	$0.06	0.08%
800	$81.74	$81.81	$0.07	0.09%
900	$90.83	$90.91	$0.08	0.09%
1,000	$99.93	$100.02	$0.09	0.09%
1,100	$111.20	$111.30	$0.10	0.09%
1,200	$122.45	$122.57	$0.12	0.10%
1,300	$133.72	$133.86	$0.14	0.10%
1,400	$144.98	$145.13	$0.15	0.10%
1,500	$156.26	$156.41	$0.15	0.10%
1,600	$167.52	$167.68	$0.16	0.10%
2,000	$212.57	$212.79	$0.22	0.10%
3,000	$325.21	$325.56	$0.35	0.11%
4,000	$437.86	$438.32	$0.46	0.11%
5,000	$550.50	$551.09	$0.59	0.11%

* Net rate including Schedules 91, 98, 290 and 297.

Note: Assumed average billing cycle length of 30.42 days.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 23 + Cost-Based Supply Service
General Service - Secondary 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	$67	$76	0.07%	0.07%
	750	$92	$101	$92	$101	0.08%	0.07%
	1,000	$117	$126	$117	$126	0.08%	0.07%
	1,500	$166	$175	$166	$175	0.08%	0.08%
10	1,000	$117	$126	$117	$126	0.08%	0.07%
	2,000	$215	$224	$216	$225	0.08%	0.08%
	3,000	$314	$323	$315	$323	0.09%	0.09%
	4,000	$399	$408	$400	$409	0.09%	0.09%
20	4,000	$431	$440	$431	$440	0.08%	0.08%
	6,000	$601	$610	$602	$610	0.08%	0.08%
	8,000	$771	$780	$772	$781	0.08%	0.08%
	10,000	$942	$951	$942	$951	0.08%	0.08%
30	9,000	$919	$928	$920	$929	0.08%	0.08%
	12,000	$1,175	$1,183	$1,175	$1,184	0.08%	0.08%
	15,000	$1,430	$1,439	$1,431	$1,440	0.08%	0.08%
	18,000	$1,686	$1,694	$1,687	$1,696	0.08%	0.08%

* Net rate including Schedules 91, 290 and 297.

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

		Monthly Billing*				Percent Difference	
		Present Price		Proposed Price			
kW Load Size	kWh	Single Phase	Three Phase	Single Phase	Three Phase	Single Phase	Three Phase
5	500	$66	$75	$66	$75	0.08%	0.05%
	750	$91	$99	$91	$100	0.08%	0.07%
	1,000	$115	$124	$115	$124	0.08%	0.07%
	1,500	$163	$172	$164	$172	0.09%	0.08%
10	1,000	$115	$124	$115	$124	0.08%	0.07%
	2,000	$212	$221	$212	$221	0.08%	0.09%
	3,000	$309	$318	$309	$318	0.09%	0.09%
	4,000	$392	$401	$393	$402	0.09%	0.09%
20	4,000	$423	$432	$424	$433	0.09%	0.08%
	6,000	$591	$600	$591	$600	0.08%	0.08%
	8,000	$758	$767	$759	$767	0.08%	0.08%
	10,000	$925	$934	$926	$935	0.08%	0.08%
30	9,000	$904	$912	$904	$913	0.08%	0.08%
	12,000	$1,155	$1,163	$1,155	$1,164	0.08%	0.08%
	15,000	$1,405	$1,414	$1,407	$1,415	0.08%	0.08%
	18,000	$1,656	$1,665	$1,658	$1,667	0.08%	0.08%

* Net rate including Schedules 91, 290 and 297.

Pacific Power
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	$326	$326	0.07%
	4,500	$421	$421	0.09%
	7,500	$611	$612	0.10%
31	6,200	$652	$652	0.08%
	9,300	$849	$849	0.09%
	15,500	$1,243	$1,244	0.10%
40	8,000	$835	$836	0.08%
	12,000	$1,089	$1,090	0.09%
	20,000	$1,598	$1,599	0.10%
60	12,000	$1,244	$1,245	0.08%
	18,000	$1,625	$1,627	0.09%
	30,000	$2,388	$2,390	0.10%
80	16,000	$1,647	$1,648	0.08%
	24,000	$2,155	$2,157	0.09%
	40,000	$3,171	$3,175	0.10%
100	20,000	$2,049	$2,051	0.08%
	30,000	$2,685	$2,687	0.09%
	50,000	$3,955	$3,959	0.10%
200	40,000	$4,030	$4,034	0.08%
	60,000	$5,301	$5,306	0.09%
	100,000	$7,842	$7,850	0.11%

* Net rate including Schedules 91, 290 and 297.

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

kW		Monthly Billing*		Percent
Load Size	kWh	Present Price	Proposed Price	Difference
15	4,500	$424	$425	0.10%
	6,000	$513	$514	0.11%
	7,500	$602	$603	0.12%
31	9,300	$849	$850	0.10%
	12,400	$1,033	$1,034	0.11%
	15,500	$1,217	$1,219	0.12%
40	12,000	$1,088	$1,089	0.10%
	16,000	$1,326	$1,327	0.11%
	20,000	$1,563	$1,565	0.12%
60	18,000	$1,622	$1,624	0.10%
	24,000	$1,979	$1,981	0.11%
	30,000	$2,335	$2,338	0.12%
80	24,000	$2,148	$2,150	0.10%
	32,000	$2,624	$2,627	0.11%
	40,000	$3,099	$3,103	0.12%
100	30,000	$2,674	$2,677	0.10%
	40,000	$3,268	$3,272	0.11%
	50,000	$3,863	$3,867	0.12%
200	60,000	$5,270	$5,275	0.11%
	80,000	$6,458	$6,466	0.12%
	100,000	$7,647	$7,656	0.12%

* Net rate including Schedules 91, 290 and 297.

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

kW		Monthly Billing*		Percent
Load Size	kWh	Present Price	Proposed Price	Difference
100	20,000	$2,487	$2,489	0.07%
	30,000	$2,961	$2,964	0.09%
	50,000	$3,909	$3,914	0.12%
200	40,000	$4,463	$4,467	0.08%
	60,000	$5,411	$5,417	0.10%
	100,000	$7,307	$7,317	0.13%
300	60,000	$6,620	$6,626	0.08%
	90,000	$8,042	$8,051	0.10%
	150,000	$10,887	$10,901	0.13%
400	80,000	$8,649	$8,657	0.09%
	120,000	$10,545	$10,556	0.11%
	200,000	$14,338	$14,356	0.13%
500	100,000	$10,713	$10,722	0.09%
	150,000	$13,083	$13,097	0.11%
	250,000	$17,824	$17,847	0.13%
600	120,000	$12,777	$12,788	0.09%
	180,000	$15,621	$15,638	0.11%
	300,000	$21,310	$21,338	0.13%
800	160,000	$16,905	$16,920	0.09%
	240,000	$20,698	$20,720	0.11%
	400,000	$28,282	$28,320	0.13%
1000	200,000	$21,033	$21,052	0.09%
	300,000	$25,774	$25,802	0.11%
	500,000	$35,255	$35,301	0.13%

* Net rate including Schedules 91, 290 and 297.

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

kW		Monthly Billing*		Percent
Load Size	kWh	Present Price	Proposed Price	Difference
100	30,000	$2,951	$2,954	0.11%
	40,000	$3,427	$3,431	0.12%
	50,000	$3,902	$3,908	0.13%
200	60,000	$5,404	$5,410	0.11%
	80,000	$6,356	$6,364	0.13%
	100,000	$7,307	$7,318	0.14%
300	90,000	$8,028	$8,038	0.12%
	120,000	$9,456	$9,468	0.13%
	150,000	$10,883	$10,899	0.14%
400	120,000	$10,551	$10,563	0.12%
	160,000	$12,454	$12,471	0.13%
	200,000	$14,357	$14,378	0.14%
500	150,000	$13,087	$13,102	0.12%
	200,000	$15,466	$15,487	0.13%
	250,000	$17,845	$17,871	0.14%
600	180,000	$15,623	$15,642	0.12%
	240,000	$18,478	$18,503	0.13%
	300,000	$21,333	$21,364	0.15%
800	240,000	$20,695	$20,720	0.12%
	320,000	$24,502	$24,535	0.14%
	400,000	$28,308	$28,350	0.15%
1000	300,000	$25,767	$25,799	0.12%
	400,000	$30,526	$30,567	0.14%
	500,000	$35,284	$35,335	0.15%

* Net rate including Schedules 91, 290 and 297.

Pacific Power
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	December-March Monthly Bill	Annual Load Size Charge	April - November Monthly Bill	December-March Monthly Bill	Annual Load Size Charge	April - November Monthly Bill	December-March Monthly Bill	Annual Load Size Charge
Single Phase										
10	2,000	$162	$162	$177	$162	$162	$177	0.10%	0.10%	0.00%
	3,000	$243	$243	$177	$244	$244	$177	0.10%	0.10%	0.00%
	5,000	$405	$405	$177	$406	$406	$177	0.10%	0.10%	0.00%
Three Phase										
20	4,000	$324	$324	$354	$325	$325	$354	0.10%	0.10%	0.00%
	6,000	$487	$487	$354	$487	$487	$354	0.10%	0.10%	0.00%
	10,000	$811	$811	$354	$812	$812	$354	0.10%	0.10%	0.00%
100	20,000	$1,622	$1,622	$1,582	$1,623	$1,623	$1,582	0.10%	0.10%	0.00%
	30,000	$2,433	$2,433	$1,582	$2,435	$2,435	$1,582	0.10%	0.10%	0.00%
	50,000	$4,054	$4,054	$1,582	$4,059	$4,059	$1,582	0.10%	0.10%	0.00%
300	60,000	$4,865	$4,865	$3,987	$4,870	$4,870	$3,987	0.10%	0.10%	0.00%
	90,000	$7,298	$7,298	$3,987	$7,305	$7,305	$3,987	0.10%	0.10%	0.00%
	150,000	$12,163	$12,163	$3,987	$12,176	$12,176	$3,987	0.10%	0.10%	0.00%

* Net rate including Schedules 91, 98, 290 and 297.

Pacific Power
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	December-March Monthly Bill	Annual Load Size Charge	April - November Monthly Bill	December-March Monthly Bill	Annual Load Size Charge	April - November Monthly Bill	December-March Monthly Bill	Annual Load Size Charge
Single Phase										
10	3,000	$239	$239	$175	$239	$239	$175	0.10%	0.10%	0.00%
	4,000	$318	$318	$175	$319	$319	$175	0.10%	0.10%	0.00%
	5,000	$398	$398	$175	$398	$398	$175	0.10%	0.10%	0.00%
Three Phase										
20	6,000	$477	$477	$350	$478	$478	$350	0.10%	0.10%	0.00%
	8,000	$636	$636	$350	$637	$637	$350	0.10%	0.10%	0.00%
	10,000	$796	$796	$350	$796	$796	$350	0.10%	0.10%	0.00%
100	30,000	$2,387	$2,387	$1,562	$2,389	$2,389	$1,562	0.10%	0.10%	0.00%
	40,000	$3,182	$3,182	$1,562	$3,186	$3,186	$1,562	0.10%	0.10%	0.00%
	50,000	$3,978	$3,978	$1,562	$3,982	$3,982	$1,562	0.10%	0.10%	0.00%
300	90,000	$7,160	$7,160	$3,925	$7,168	$7,168	$3,925	0.10%	0.10%	0.00%
	120,000	$9,547	$9,547	$3,925	$9,557	$9,557	$3,925	0.10%	0.10%	0.00%
	150,000	$11,934	$11,934	$3,925	$11,946	$11,946	$3,925	0.10%	0.10%	0.00%

* Net rate including Schedules 91, 98, 290 and 297.

Pacific Power
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	$25,757	$25,785	0.11%
	500,000	$34,819	$34,867	0.14%
	700,000	$43,882	$43,948	0.15%
2,000	600,000	$50,913	$50,970	0.11%
	1,000,000	$66,789	$66,883	0.14%
	1,400,000	$83,814	$83,947	0.16%
6,000	1,800,000	$136,355	$136,525	0.12%
	3,000,000	$187,431	$187,715	0.15%
	4,200,000	$238,507	$238,905	0.17%
12,000	3,600,000	$270,555	$270,895	0.13%
	6,000,000	$372,707	$373,275	0.15%
	8,400,000	$474,860	$475,655	0.17%

Notes:

On-Peak kWh	38.23%
Off-Peak kWh	61.77%

* Net rate including Schedules 91 and 290. Schedule 297 included for kWh levels under 730,000.

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

kW		Monthly Billing		Percent
Load Size	kWh	Present Price	Proposed Price	Difference
1,000	300,000	$23,985	$24,010	0.11%
	500,000	$32,528	$32,571	0.13%
	700,000	$41,072	$41,131	0.14%
2,000	600,000	$47,401	$47,452	0.11%
	1,000,000	$62,238	$62,322	0.14%
	1,400,000	$78,225	$78,343	0.15%
6,000	1,800,000	$134,795	$134,947	0.11%
	3,000,000	$182,756	$183,009	0.14%
	4,200,000	$230,718	$231,071	0.15%
12,000	3,600,000	$267,549	$267,853	0.11%
	6,000,000	$363,472	$363,977	0.14%
	8,400,000	$459,394	$460,102	0.15%

Notes:

On-Peak kWh	38.23%
Off-Peak kWh	61.77%

* Net rate including Schedules 91 and 290. Schedule 297 included for kWh levels under 730,000.

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

kW		Monthly Billing		Percent
Load Size	kWh	Present Price	Proposed Price	Difference
1,000	500,000	$30,639	$30,681	0.14%
	700,000	$38,584	$38,643	0.15%
2,000	1,000,000	$58,294	$58,378	0.14%
	1,400,000	$73,083	$73,201	0.16%
6,000	3,000,000	$172,319	$172,571	0.15%
	4,200,000	$216,688	$217,042	0.16%
12,000	6,000,000	$342,255	$342,760	0.15%
	8,400,000	$430,995	$431,701	0.16%

Notes:

On-Peak kWh	37.63%
Off-Peak kWh	62.37%

* Net rate including Schedules 91 and 290. Schedule 297 included for kWh levels under 730,000.