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May 25, 2022

Via Electronic Filing

Public Utility Commission of Oregon
Attn: Filing Center
201 High St. SE, Suite 100
Salem OR 97301

Re: In the Matter of PACIFICORP, dba PACIFIC POWER
2023 Transition Adjustment Mechanism.
Docket No. UE 400

Dear Filing Center:

Please find enclosed the Opening Testimony and Exhibits of Bradley G. Mullins (AWEC/100 – 107) on behalf of the Alliance of Western Energy Consumers ("AWEC") in the above-referenced docket.

Please note that Exhibit AWEC/102 contains Protected Information that is being handled in accordance with Order No. 16-128. The confidential version of Exhibit AWEC/102 has been encrypted with 7-zip software and is being transmitted electronically to the Commission and qualified persons.

Thank you for your assistance. If you have any questions, please do not hesitate to call.

Sincerely,

/s/ Jesse O. Gorsuch
Jesse O. Gorsuch

Enclosures

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that I have this day served **Confidential Exhibit AWEC/102** upon the parties shown below by sharing an encrypted copy via electronic mail and by posting to the Huddle workspace in this docket.

Dated this 25th day of May, 2022.

Sincerely,

/s/ Jesse O. Gorsuch
Jesse O. Gorsuch

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BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UE 400

In the Matter of	)
	)
PACIFICORP,	)
	)
2023 Transition Adjustment Mechanism.	)
	)
	)

OPENING TESTIMONY OF

BRADLEY G. MULLINS

ON BEHALF OF

ALLIANCE OF WESTERN ENERGY CONSUMERS

MAY 25, 2022

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EXHIBIT LIST

I. INTRODUCTION AND SUMMARY

Q. PLEASE STATE YOUR NAME AND OCCUPATION.

A. My name is Bradley G. Mullins. I am a Consultant for MW Analytics, an independent consulting firm representing utility customers before state public utility commissions in the Northwest and Intermountain West. My witness qualification statement can be found in Exhibit AWEC/101.

Q. PLEASE IDENTIFY THE PARTY ON WHOSE BEHALF YOU ARE TESTIFYING.

A. I am testifying on behalf of the Alliance of Western Energy Consumers ("AWEC"). AWEC is a non-profit trade association whose members are large energy users in the Western United States, including customers receiving electric services from PacifiCorp.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I discuss my initial review of PacifiCorp's proposed $69,973,978 increase to Oregon revenues, including its forecast of 2023 Net Power Costs ("NPC") of $1,683,929,924 using the AURORA electric modeling software.

Q. WHAT WAS THE SCOPE OF YOUR REVIEW?

A. I reviewed PacifiCorp's filed testimony, workpapers and NPC models. I submitted multiple rounds of data requests and reviewed PacifiCorp's responses to those requests. Responses to select data requests are attached as Exhibit AWEC/102.

Q. PLEASE SUMMARIZE YOUR INITIAL RECOMMENDATIONS.

A. My initial recommendations are summarized in Table 1, below.

Table 1
AWEC Initial TAM Revenue Adjustment Estimates
Whole Dollars

Initial Filing	**69,973,978**
PTC Rate	(2,599,610)
Utah Schedule 34 Load	(5,091,533)
Utah DSM	(1,598,392)
Non-Firm Wheeling Error	(2,262,447)
Market Caps	(18,957,581)
PSCo Sale	(3,610,891)
Emergency Purchases	(2,388,803)
Total Initial Adjustments	(36,509,257)
Adjusted NPC	**33,464,720**

It should be noted that, while PacifiCorp's power cost update in this case would result in a 7.7% rate increase for industrial customers,[1] when combined with PacifiCorp's concurrent general rate case and its recent Power Cost Adjustment Mechanism filing, industrial customers are potentially looking at an overall rate increase of 19.2% on or about January 1, 2023.[2]

II. INITIAL ADJUSTMENTS

a. Production Tax Credit Rate

Q. WHAT PTC RATE DID PACIFICORP INCLUDE IN ITS FILING?

A. In its initial filing in this proceeding, PacifiCorp forecast a PTC rate of 2.7 cents per kWh. That value represents an increase from the 2.6 cents per kWh value that PacifiCorp agreed to include based on my Opening Testimony in Docket No. UE 390 (the "2022 TAM").[3]

1 Exh. PAC/403, Ridenour/1.
2 Docket UE 399, Exh. PAC/1110, Meredith/1; Docket UE 404, Exh. PAC/203, Meredith/1.
3 See UE 390, PAC/400, Staples/5:14-17.

Q. HOW DOES THE PTC RATE CHANGE FROM YEAR TO YEAR?

A. The detailed mechanics of the PTC rate were discussed in my Opening Testimony in UE 390. As noted in my prior testimony, the IRS adjusts the PTC rate each year by applying an *inflation adjustment factor*.[4] The inflation adjustment factor is an indexed value that the IRS calculates based on the *GDP implicit price deflator*, which itself is an economic index of inflation published by the Department of Commerce, Bureau of Economic Analysis. The Bureau of Economic Analysis publishes the GDP implicit price deflator each quarter, and from that information, the expected GDP implicit price deflator value for calendar year 2023 can be assessed.

Q. WHAT WILL THE PTC RATE BE IN 2023?

A. In Exhibit AWEC/103, I perform a forecast of the PTC rate for 2023 using the same analysis I presented in the 2022 TAM, where PacifiCorp accepted my recommendation. At the time of drafting this testimony, the Bureau of Economic Analysis has published its GDP implicit price deflator for first quarter of 2022.[5] Based on that publication, it can be determined that the PTC rate will increase to 2.8 cents 2023 even if one assumes zero inflation for the remainder of 2022. Since inflation is expected to be positive in 2022, I recommend that a 2.8 cents per kWh rate be used in the 2023 TAM.

Q. IS YOUR RECOMMENDATION CONSISTENT WITH THE FORECAST OF PORTLAND GENERAL ELECTRIC COMPANY?

A. Yes. In Exhibit AWEC/104, I have attached a non-confidential workpaper from Docket No. UE 402 where PGE forecast a 2.8 cent per kWh PTC rate for 2023.

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4 26 U.S.C. § 45(b)(2) (2022).

5 The published data is provided at https://apps.bea.gov/histdata/histChildLevels.cfm?HMI=7 (accessed May 23, 2022)

Q. WHAT IS THE IMPACT OF THIS RECOMMENDATION?

A. I estimate the impact of this recommendation as a reduction of $2,599,610 to Oregon-allocated TAM revenues.

b. <u>Utah Schedule 34</u>

Q. PLEASE SUMMARIZE YOUR RECOMMENDATION RELATED TO UTAH SCHEDULE 34.

A. PacifiCorp has a green tariff program in Utah under Utah Rate Schedule 34. Only one customer is participating in the program. In calculating Oregon's allocation factors, PacifiCorp has removed the Utah Schedule 34 Customer from Utah's dynamic allocation factors, which results in an increased amount of costs being allocated to Oregon customers. This treatment, however, is not consistent with the 2020 Protocol, which requires all loads PacifiCorp serves to be included in the load based dynamic allocation factors. Accordingly, I recommend that the jurisdictional allocation factors used in this proceeding be recalculated with the Utah Schedule 34 Customer's entire load included in the Load-Based Dynamic Allocation Factors.

Q. WHAT IS UTAH SCHEDULE 34?

A. Utah Schedule 34, attached as Exhibit AWEC/105, is a green tariff program available to large customers in Utah with loads exceeding 5,000 KW. Under the Utah Schedule 34 tariff, the terms and conditions of service are established in a "Renewable Energy Service Contract."

Q. HOW MANY CUSTOMERS ARE BEING SERVED ON UTAH SCHEDULE 34?

A. In response to AWEC Data Request 36, PacifiCorp stated that "[a]t this time, there is only one customer on Utah Schedule 34 during the test period." The Utah Public Service Commission ("UT PSC") approved this Utah Schedule 34 Customer's contract in Docket 16-035-27.[6]

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[6] See https://psc.utah.gov/2016/06/23/docket-no-16-035-27/

Q. WHAT ARE THE PRICE TERMS AND CONDITIONS OF THE UTAH SCHEDULE 34 CUSTOMER'S RENEWABLE ENERGY SERVICE CONTRACT?

A. The terms and conditions of the contract were redacted in UT PSC Docket 16-035-27, and therefore, are unknown. Based on PacifiCorp's responses to discovery, such as its responses to AWEC Data Request 22 and AWEC Data Request 34, it appears that the Utah Schedule 34 Customer contract is structured like a green tariff program. The Utah Schedule 34 Customer has the ability to take services from at least eight different dedicated solar facilities with the ability to offset its tariff rates based on the cost of those resources.

Q. HOW IS SUCH A CONTRACT HANDLED UNDER THE 2020 PROTOCOL?

A. Section 3.1.6 of the 2020 Protocol states that "loads of Special Contract customers [are] included in Load-Based Dynamic Allocation Factors." While the Utah Schedule 34 contract is described as "Renewable Energy Service Contract," the 2020 Protocol defines it as a Special Contract, "a contract entered into between PacifiCorp and one of its retail customers with prices, terms, and conditions different from otherwise-applicable tariff rates."[7] Since the Utah Schedule 34 Customers would otherwise receive services based on the prices, terms and conditions of Utah Schedule 8 or Schedule 9, a Renewable Energy Service Contract approved under Utah Schedule 34, which provides for different prices, terms and conditions than the otherwise applicable rates, meets the definition of a Special Contract under the 2020 Protocol.

[7] 2020 Protocol, Appendix A at 7-8.

Q. DOES THE FACT THAT PACIFICORP'S GREEN TARIFF PROGRAM IN UTAH IS DEFINED IN A TARIFF IMPACT THE CONCLUSION THAT CONTRACTS ENTERED INTO UNDER SCHEDULE 34 ARE "SPECIAL CONTRACT" UNDER THE 2020 PROTOCOL?

A. No. The 2020 Protocol defines a special contract as one that includes prices that are "different from otherwise applicable tariff rates." Other than an administrative charge, Schedule 34 has no stated rates, and specifies that rates will be identified in each contract with a participating customer.[8] Therefore, Schedule 34 does not provide applicable tariff rates.

Q. HOW HAS PACIFICORP HANDLED THE UTAH SCHEDULE 34 CUSTOMER LOAD IN THIS FILING?

A. While the treatment was not described in testimony, it appears that the Utah Schedule 34 Customer loads are being excluded from the Load-Based Dynamic Allocation Factors, treatment which is inconsistent with the allocation of Special Contracts in the 2020 Protocol. There appears to have been substantial testimony discussing the interjurisdictional allocation of the Utah Schedule 34 Customer load in UT PSC Docket 16-035-27, although the testimony was redacted, and the Commission does not have the benefit of that discussion. Notwithstanding, in response to AWEC Data Request 35, PacifiCorp identified the following language in the Utah Schedule 34 Customer's contract:

> Energy: energy supplied by the renewable resources is excluded from jurisdictional allocation factors. Any energy supplied by PacifiCorp is included in the jurisdictional allocation factors.
>
> Capacity (coincident peak (CP)): capacity served by the renewable resource is excluded for the monthly renewable generation, not to exceed the customer's demand. Any capacity supplied by PacifiCorp is included in the monthly CP.

[8] Exh. AWEC/105.

Thus, in the calculation of the Load-Based Dynamic Allocation Factors, the load of the Utah Schedule 34 Customer is being offset by the generation supplied by the dedicated green tariff resources PacifiCorp is purchasing for the customer.

Q. DOES THE UTAH SCHEDULE 34 CUSTOMER'S CONTRACT HAVE ANY BEARING ON THE ALLOCATION OF COSTS UNDER THE 2020 PROTOCOL?

A. No. The 2020 Protocol generally does not allow customers or states to avoid their share of fixed system costs through the Load-Based Dynamic Allocation Factors by entering into an agreement with special terms regarding interjurisdictional allocation. Indeed, Appendix G of the 2020 Protocol establishes that, for Special Contracts both with and without Ancillary Service Contract Attributes, "Loads of Special Contract customers **will be included** in all Load-Based Dynamic Allocation Factors."[9]

Furthermore, PacifiCorp's Oregon customers have long been prohibited from such treatment with respect to Direct Access and the New Load Direct Access Program. Those programs require customers to pay transition adjustment charges for a period of 10-years to opt-out of cost-of-service rates, a requirement of Section 3.1.8 of the 2020 Protocol. Thus, the treatment in Utah Schedule 34 Customers is inequitable because Utah avoided an allocation of any generation or transmission costs, other than the dedicated resources, used to serve the Utah Schedule 34 Customer's load. Oregon Direct Access customers pay for their own transmission and supply their own energy for their full requirements yet are not afforded this same treatment. The Utah Schedule 34 Customer supplies only partial requirements from the green tariff resources, which rely heavily on PacifiCorp's generation fleet for integration and shaping services. The Utah Schedule 34 Customer also does not pay for the cost of OATT transmission

[9] 2020 Protocol, Appendix G, p. 1 (emphasis added).

to deliver its dedicated resources to its load. Thus, the Utah Schedule 34 Customer imposes more costs on PacifiCorp's system, while being provided more favorable treatment than Oregon Direct Access customers.

Q. HOW HAS PACIFICORP HANDLED THE DEDICATED SOLAR RESOURCES IN ESTIMATING NPC?

A. It is not clear. In Opening Testimony, PacifiCorp did not describe or mention these facilities, let alone its unique treatment of the resources in the calculation of NPC. In its workpaper "ORTAM23 NPC CONF," Tab "UT Solar Adjustment," it appears that PacifiCorp made an adjustment where it repriced a portion of the facilities' energy based on Utah Schedule 37 rates effective in 2018. Notwithstanding, in response to AWEC Data Request 20, PacifiCorp identified a significant error associated with that workpaper. In its May 5, 2022 List of Corrections and Omissions, PacifiCorp noted that correcting this error will decrease total-company Net Power Costs by $11,400,000, although PacifiCorp did not provide the corrected workpapers.

Q. DID THE UTAH SCHEDULE 34 DEDICATED RESOURCES FOLLOW OREGON'S RESOURCES PROCUREMENT GUIDELINES?

A. No. A request for proposal meeting Oregon's procurement guidelines was not undertaken. In Data Request 22, AWEC requested the economic analyses supporting the Appaloosa I-A and Appaloosa I-B projects. PacifiCorp responded, for example, that no such economic analysis was undertaken because "100 percent of the costs associated with the PPAs are passed through to an individual customer under Utah Electric Service Schedule 34."

Q. WHAT DO YOU RECOMMEND?

A. I recommend that the Utah Customer load be considered consistent with the 2020 Protocol. Specifically, I recommend the entire amount of the Utah Customer load and demand be included in jurisdictional allocation factors, as required by the 2020 Protocol.

Q. WHAT IS THE IMPACT OF THIS RECOMMENDATION?

A. This recommendation will have impacts in both this proceeding and the ongoing general rate case in Docket No UE 399. PacifiCorp provided the calculation of System Energy ("SE") and System Generation ("SG") interjurisdictional allocation factors in response to AWEC Data Request 14. As can be seen from the attachment to that response, significant adjustments were made reducing Utah's allocation factors. In AWEC Data Request 36, PacifiCorp was requested to provide the loads of the Utah Schedule 34 Customer. PacifiCorp objected and did not provide the information. In response to AWEC Data Request 38, PacifiCorp described the specific adjustments that it made to the Utah allocation factors, including Demand Side Management, Special Contract Load Curtailment and the Utah Schedule 34 Customer. In the Confidential Attachment 2 of PacifiCorp's response to AWEC Data Request 39, PacifiCorp provided greater detail of the adjustments to Utah's allocation factors. From that response, it appears that PacifiCorp included the Utah Schedule 34 Customer Load in the Special Contract category, along with Special Contract load curtailments, although the precise load is unknown. Accordingly, in Table 2, below. I have approximated the impact of PacifiCorp's special treatment for the Utah Schedule 34 Customer on Oregon's allocation factors based on my understanding of the approximate volume of Special Contract load curtailments.

Table 2
Approximate Impact of Utah Schedule 34 Customer on Allocation Factors

	SE	SG
PacifiCorp Filed	25.07%	26.07%
With Utah Sch. 34 Load	25.17%	25.88%

Based on the above calculation, PacifiCorp's treatment of excluding the Utah Schedule 34 Customer load from Utah's allocation factors has resulted in an approximate $5,091,533 increase to the TAM revenue requirement in this proceeding Since the workpapers PacifiCorp provided contained an error, however, it is not possible to fully estimate the corresponding impact of this recommendation on the cost of the Utah Schedule 34 Customer's dedicated resources.

c. Utah Demand Side Management

Q. WHAT ADJUSTMENT DOES PACIFICORP MAKE TO THE LOAD BASED DYNAMIC ALLOCATION FACTORS FOR UTAH DEMAND SIDE MANAGEMENT?

A. In response to AWEC Data Request 37, Confidential Attachment 2, it can be noted that PacifiCorp made an adjustment to Utah's demand for a demand side management program.

Q. HOW IS DEMAND SIDE MANAGEMENT CONSIDERED IN THE 2020 PROTOCOL?

A. In Section 3.1.2.1 of the 2020 Protocol, "[b]enefits from [demand-side management] programs, in the form of reduced consumption and contribution to Coincident Peak, will be reflected in the Load-Based Dynamic Allocation Factors."

Q. IS IT NECESSARY FOR PACIFICORP TO INCLUDE AN ADJUSTMENT FOR UTAH DEMAND-SIDE MANAGEMENT IN THE ALLOCATION FACTORS?

A. No. To the extent that the Coincident Peaks are being reduced by Utah's demand side management programs, those reductions would have otherwise already been considered in Utah's load forecast. Further, Oregon does not receive a similar reduction to its peak load requirements for its investment in energy efficiency through the Energy Trust of Oregon.

Q. WHAT DO YOU RECOMMEND?

A. I recommend removing the Utah demand-side management adjustment from the calculation of the Load-Based Dynamic Allocation Factors. This recommendation results in a $1,598,392 reduction to Oregon allocated NPC.

d. <u>Oregon Situs Assignment Calculations</u>

Q. PLEASE DESCRIBE THE ERROR PACIFICORP MADE IN ITS SITUS ASSIGNMENT CALCULATIONS.

A. In workpaper "TAM Allocation - CY 2023 - Initial Filing," Tab "Oregon Situs - 2023 Initial," PacifiCorp identified an Oregon situs adjustment reduction to NPC of $430,221. In AWEC Data Request 45, PacifiCorp was requested to provide workpapers supporting the hardcoded values that were used to calculate that adjustment. In its response, PacifiCorp omitted the workpapers supporting the reasonable energy price calculations for situs assigned qualifying facility resources. Accordingly, I have been unable to validate the Oregon situs assignment adjustment. I recommend PacifiCorp provide an explanation of how situs assigned qualifying facility resources are handled in its reply and provide workpapers supporting the situs assignment calculations.

e. Non-Firm Wheeling Error

Q. HAVE YOU IDENTIFIED ANY ERRORS IN PACIFICORP'S CALCULATION OF NON-FIRM WHEELING EXPENSE?

A. Yes. Oregon is the only state using 48-months of non-firm wheeling expense. Other states use 12 months of data, consistent with other wheeling expenses. Accordingly, when calculating wheeling expenses for Oregon in the workpaper "GNw_Wheeling CONF," PacifiCorp will normally deduct the non-firm wheeling expense calculated over 12 months and add back the non-firm wheeling expense calculated over 48 months. In this proceeding, however, PacifiCorp's wheeling workpaper contained an error. The workpaper added back the non-firm wheeling expense calculated over 48 months for just 6 months of the test period and failed to deduct the wheeling expenses calculated over 12 months. Correcting the workpaper reduces total-Company wheeling expense by $8,914,255, with $2,262,447 of the reduction allocated to Oregon.

f. Short-Term Transmission

Q. HOW IS SHORT-TERM FIRM TRANSMISSION INCLUDED IN AURORA?

A. In addition to long-term transmission, PacifiCorp models short-term transmission, including short-term firm and non-firm transmission, as distinct links in AURORA. Since those transactions often occur in day ahead and real-time markets, PacifiCorp does not necessarily know how much short-term firm or non-firm transmission it will have available in the test period. Accordingly, in past proceedings PacifiCorp has modeled short-term firm transmission in GRID using 48 months of historical data.

In this proceeding, however, PacifiCorp's treatment of short-term transmission is not clear. The specific short-term link capacities included in AURORA may be found in the workpaper "Aurora GN Transmission Links CONF", tab "1 Transmission Links." In AWEC

Data Request 10, AWEC requested PacifiCorp provide the workpapers used to calculate the transmission capacity for these short-term firm transmission links. In response, PacifiCorp provided two files that contained actual short-term and non-firm transmission in calendar year 2021. The specific link capacity values input into AURORA, however, were not contained in the files PacifiCorp provided. Accordingly, I was unable to verify how PacifiCorp modeled short-term transmission in this proceeding.

Q. IS PACIFICORP'S APPROACH CONSISTENT WITH ITS PAST PRACTICE?

A. Based on its response to AWEC Data Request 10, it is possible that PacifiCorp has modeled short-term transmission transactions using data from calendar 2021, which would represent a modeling change from past proceedings, which have used 48 months of data. This was not listed as a modeling change or discussed in testimony.

Q. DID YOU INDEFINITY ANY ERRORS IN THE FILE PACIFICORP PROVIDED?

A. Yes. There were many short-term transmission purchases in the data that PacifiCorp provided which were marked as excluded. These link capacities were allegedly "intra-bubble" transactions occurring within the same transmission area, and thus, not requiring separate transmission capacity in AURORA. Upon review, however, many of these links are not appropriately excluded because they in fact occur between two separate transmission areas in PacifiCorp's new transmission topology. These included transmission between the Red Butte substation and the Mead Market and transmission from Avista's system to the Mid-C market. The Red Butte substation is in Southern Utah and Mead is a market hub in Northern Nevada. Accordingly, it would have been more appropriate to model transmission between these two points as a link between Utah South and the Mead Market. PacifiCorp uses wheeling on Avista's system to facilitate transfers from Western Idaho. Accordingly, transactions from

Avista's system to the Mid-C market, which were also excluded, are appropriately modeled as a link between Idaho West and the Mid-C Market.

Further, in the data PacifiCorp provided, PacifiCorp did not detail short-term transmission that it has acquired on PacifiCorp Transmission's system. In addition to the long-term link capacities on PacifiCorp Transmission's system, PacifiCorp also can procure short-term firm and non-firm transmission on PacifiCorp Transmission's system to serve its load requirements. This capability was not considered in the long-term link capacities, or the data provided in response to AWEC Data Request 10.

Q. WHAT DO YOU RECOMMEND?

A. Given the capability of AURORA, which provides more flexibility in modeling transmission, it may be possible to transition to a more streamlined approach to modeling short-term transmission. I recommend PacifiCorp respond to the issues above in Reply Testimony and explain how it has modeled short-term transmission in AURORA. I may propose an adjustment depending on the information PacifiCorp provides on this topic.

g. GRID Market Caps

Q. WHAT DOES PACIFICORP PROPOSE RELATED TO MARKET CAPS?

A. Market Caps were a specific modeling input in the GRID model used to address what PacifiCorp saw as a shortcoming in the way the GRID model overoptimized forecast sales transactions. In this proceeding, PacifiCorp states that AURORA "does not consider load requirements, transmission constraints, market illiquidity, or static assumptions about market prices that prevent the Company from making sales or purchases at the forecast price,"[10] and

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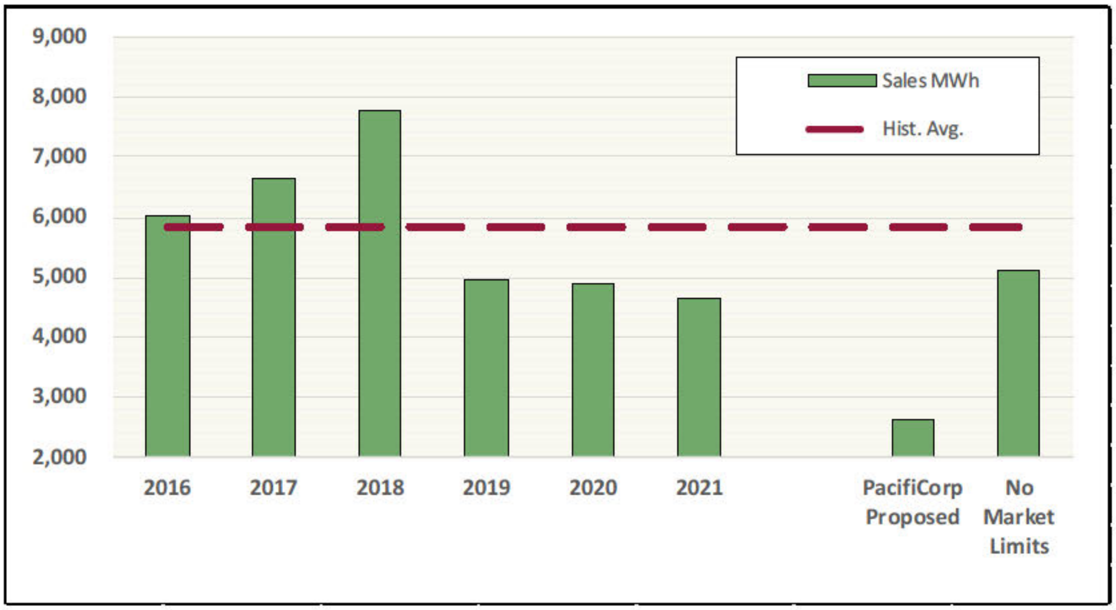
[10] PAC/100, Wilding/28 at 3-5.

proposes new modeling to duplicate Market Caps in the AURORA model. Since the AURORA model does not contain an input for Market Caps, PacifiCorp used a work-around to duplicate GRID Market Caps in AURORA. Specifically, PacifiCorp has attempted to duplicate Market Caps in AURORA by modeling sales transactions in a separate transmission area with a fictitious transmission link between the market hub and with the link capability corresponding to the Market Cap limits. In addition, PacifiCorp has proposed to calculate the limits using average data, even though the Commission has repeatedly rejected that approach.

Q. WHAT DO YOU RECOMMEND?

A. Given the move to AURORA, I recommend that Market Caps be eliminated. The AURORA model is already producing a level of sales that is significantly below the historical levels, so continuing to apply a limit on market sales is no longer necessary. In Exhibit AWEC/106, I perform an analysis comparing the sales forecast in AURORA to the historical level of sales. I detailed this analysis both including and excluding book-out transactions. The result of this analysis, excluding book-out transactions, can be seen in Figure 1, below.

Figure 1
Sales Volumes Excluding DA/RT and Book-Outs



To form an apples-to-apples comparison, it is necessary to either include or exclude book-out transactions in both the historical data and the forecast data. PacifiCorp's analysis in Direct Testimony is therefore not accurate because it ignores book-outs, leading to an "apples-to-oranges" comparison. In the above analysis, I excluded both book-outs and the DA/RT volumes from the calculation. As can be seen, when the Market Cap modeling is eliminated, the level of sales produced is still less than the historical average. It is also in line with the level of sales experienced since 2019, although higher than average sales volumes are expected given high market prices. Thus, with the move to AURORA, it is not necessary to duplicate the GRID Market Cap modeling assumption.

Q. ARE HIGHER SALES VOLUMES EXPECTED WITH HIGH MARKET PRICES?

A. Given high market prices, higher sales revenues and volumes would otherwise be expected in the test period.

Q. ARE SALES VOLUMES ALSO INFLUENCED BY THE DA/RT ADJUSTMENT?

A. Yes. If there is a concern with the volume of sales included in NPC, the Commission might be better served with adjusting the volumes produced in the DA/RT adjustment, than duplicating GRID Market Caps in AURORA. The volumes produced in the DA/RT adjustment contribute more volume to the sales forecast in this case than the AURORA model. These volumes, however, are a perfunctory feature of the DA/RT adjustment, and have zero impact on NPC. The DA/RT volumes are somewhat arbitrary because they assume that PacifiCorp balances 100% of its net sales and purchases with structured products, which does not necessarily correspond to its actual practice. Since these volumes don't impact NPC, the methodology used to derive them has not received attention in past proceedings.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION?

A. Removing the duplicated GRID Market Cap modeling results in a $73,603,841 reduction to total-Company NPC, with approximately $18,957,581 of the reduction allocated to Oregon.

h. <u>Hayden</u>

Q. HAS PACIFICORP EXECUTED A NEW COAL SUPPLY AGREEMENT FOR THE HAYDEN PLANT?

A. Yes. This contract is described at PAC/200, Owens/22 at 16-18.

Q. DID PACIFICORP PERFORM AN ECONOMIC ANALYSIS TO EVALUATE THE CONTRACT?

A. No. In response to AWEC Data Requests 60 and 61, PacifiCorp states that it did not perform any economic analysis with respect to the new contract.

Q. IS THE AGREEMENT PRUDENT?

A. No. Hayden is scheduled to be depreciated and removed from rates in Oregon at the end of 2023. This was noted in response to AWEC Data Request 50. In section 4.1.5 of the 2020

Protocol, PacifiCorp was required to "make State-specific recommendations to Commissions for the treatment of Hayden Units 1 and 2." This was to occur on or before February 1, 2021. Based on PacifiCorp's response to AWEC Data Request 67, that recommendation never occurred. Entering into a long-term agreement immediately before a plant is expected to be retired from rates with no supporting economic analysis is not prudent.

Q. WHAT DO YOU RECOMMEND?

A. I recommend that the Commission find the contract described at PAC/200, Owens/22 at 16-18 to be imprudent. I recommend that Oregon ratepayers not be subject to any liquidated damage costs in connection with removing Hayden 1 and 2 from Oregon rates in 2023, consistent with the 2020 Protocol.

i. <u>Craig</u>

Q. HOW DOES PACIFICORP CALCULATE COAL COSTS FOR THE CRAIG POWER PLANT?

A. Coal costs for Craig power plant are identified in the workpaper of witness Owens titled "CRAIG FLLT 2023 TAM DF Cycling." The costs of the Craig facility are based on the costs of the Trapper mine, of which PacifiCorp is a part owner.

Q. HOW DOES PACIFICORP DERIVE THE COST ESTIMATES FOR THE TRAPPER MINE?

A. The values appear to be driven by a budget from the mine itself. There are also adjustments that need to be made to remove profit interests and other items, although those details were not provided in the Owens workpaper.

Q. DID YOU REQUEST FURTHER INFORMATION REGARDING THE BUDGET PROVIDED BY THE TRAPPER MINE?

A. Yes. In AWEC Data Requests 62 through 66, I requested additional information regarding the budget for the Trapper mine. The budget itself was several years out of date, so I was concerned with its accuracy.

Q. WAS PACIFICORP ABLE TO PROVIDE ANY INFORMATION TO VALIDATE THE ACCURACY OF ITS BUDGET?

A. No. PacifiCorp repeatedly stated that "[t]his requested information is not available because Trapper mine does not provide PacifiCorp with that level of detail on plant additions." Notwithstanding, in response to AWEC Data Request 60, PacifiCorp claims it made an error by excluding certain detail from its calculation, detail which it alleged was not provided by the Trapper mine.

Q. WHAT DO YOU RECOMMEND?

A. Given that PacifiCorp has been unable to substantiate the costs from the Trapper Mine, I recommend PacifiCorp provide further information on the budget process and explain why the information is unavailable. I may recommend an adjustment after reviewing PacifiCorp's testimony on this issue.

j. PSCo Contract

Q. PLEASE PROVIDE AN OVERVIEW OF THE PSCO CONTRACT.

A. The Public Service Company of Colorado ("PSCo") contract is a new sales agreement replacing a legacy exchange agreement. In the Confidential Attachment to Data Response 24, PacifiCorp provided a memorandum that describes the confidential terms of the contract and describes PacifiCorp's decision to execute the new agreement, including the price and term of the contract.

Q. IS THE CONTRACT ECONOMIC?

A. No. Based on the time that it was issued, the contract price was below market by a large margin. In Exhibit AWEC/107, I provide an analysis comparing the new PSCo contract with the November 08, 2021, OFPC, which was the latest OFPC at the time the agreement was executed. The contract was less than 50% of the 2023 forward market at the time it was executed.

Q. DO YOU HAVE ANY OTHER CONCERNS WITH THIS CONTRACT?

A. Yes. Both Craig and Hayden are operating at very low capacity factors in the study period. In addition, AURORA is producing a large volume of trapped energy from the Colorado transmission area in the study period, indicating there is generation from Craig and Hayden that is unable to be transmitted to PacifiCorp's main system. PacifiCorp models the PSCo sale as a Demand Side Management resource, which appears to be producing unintended consequences on the Craig and Hayden facilities. My understanding was the contract was designed to avoid trapped energy from the Craig and Hayden facilities, but the opposite effect is being observed in the AURORA model.

Q. WHAT DO YOU RECOMMEND?

A. Based on the analysis in Exhibit AWEC/107, I recommend the Commission find that the PSCo contract was imprudent and recommend that the new PSCo contract be repriced based on the November 08, 2021 OFPC. The impact of this recommendation is a $14,020,653 reduction to total-Company NPC with $3,610,891 of the reduction allocated to Oregon.

k. Emergency Purchases

Q. WHAT ARE EMERGENCY PURCHASES?

A. Emergency purchases are a modeling convention that PacifiCorp applies in AURORA, which is designed to prevent the model from failing to find a dispatch solution in instances where generation is insufficient to serve the demand in a particular transmission area. Such a situation might occur when the model fails to find a dispatch solution that satisfies all constraints in the model. Emergency purchases are included as a resource in each transmission area and provided with an arbitrarily high dispatch bid-adder of $1000/MWh. Thus, the emergency purchase resource is designed to be a last resort resource in cases where the model is unable to find a satisfactory solution for a particular transmission area. If the model is developed properly, emergency purchases are expected to be minimal.

Q. HOW ARE THE COSTS OF EMERGENCY PURCHASES INCLUDED IN NPC?

A. When calculating NPC, PacifiCorp does not use the $1000/MWh dispatch price assumed in AURORA, but instead, assigns the emergency purchases a price corresponding to 150% of the nearest market price.

Q. WHAT VOLUME OF EMERGENCY PURCHASE IS INCLUDED IN PACIFICORP'S NPC STUDY?

A. Emergency purchase comprise approximately 8% of the total volume of purchase in the AURORA model. Thus, even though emergency purchases are designed as a stop gap measure to prevent the model from failing, they comprise a material portion of the purchases being made to serve loads.

Q. DO EMERGENCY PURCHASES REPRESENT AN ACTUAL COST TO PACIFICORP?

A. PacifiCorp excludes emergency purchases from the calculation of the DA/RT adjustment. If these high-cost purchases represent actual historical cost, they are appropriately considered when evaluating the average purchase price modeled in AURORA to the average DA/RT purchase price based on historical data. Stated differently, the DA/RT adjustment already considers the high cost of making emergency purchases when the system is constrained so it is unnecessary to add additional cost into NPC for the emergency purchases generated in AURORA.

Q. IS THE MODEL FUNCTIONING CORRECTLY IF IT IS PRODUCING SUCH A HIGH LEVEL OF EMERGENCY PURCHASES?

A. No. Such a high level of emergency purchases is an indication that there is a problem with the model. It is possible that the high volume of emergency purchases may be driven by faulty modeling assumptions, although I have been unable to identify the cause of the high level of emergency purchases.

Q. WHAT DO YOU RECOMMEND?

A. Given that the cost of emergency purchases made historically is already reflected in the DA/RT adjustment, I recommend that the 150% adder applied to emergency purchases be eliminated. The impact of this adjustment is a $9,274,658 reduction to total-company NPC, with approximately $2,388,803 allocated to Oregon.

l. <u>Northwest Pipeline Tax Reform Refund</u>

Q. PLEASE DESCRIBE THE REFUND AT ISSUE IN THE ONGOING NORTHWEST PIPELINE RATE CASE.

A. As a part of its prior rate case, FERC Docket No. RP17-346, the Northwest Pipeline agreed to defer the impacts of tax reform in a regulatory asset. Shippers are currently in the process of negotiating a prefiling settlement for Northwest Pipeline's upcoming rate case, which will be filed on June 1, 2022 if a settlement is not reached. In either case, approximately $130,000,000 of funds have accrued to the regulatory asset that will be returned to shippers, including PacifiCorp, starting January 1, 2023. I recommend the benefit of this refund—once it is determined, either through the filing of a settlement agreement or the filing of Northwest Pipeline's rate case—be included as a reduction to the TAM revenues in this proceeding.

Q. DOES THIS CONCLUDE YOUR OPENING TESTIMONY?

A. Yes.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UE 400

In the Matter of	)
	)
PacifiCorp, dba Pacific Power,	)
	)
2023 Transition Adjustment Mechanism.	)
	)

EXHIBIT AWEC/101

QUALIFICATION STATEMENT OF
BRADLEY G. MULLINS

MW ANALYTICS
Energy & Utility Consulting

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ABOUT

MW Analytics is the professional consulting practice of Brad Mullins, a consultant and expert witness that represents utility customers in regulatory proceedings before state utility commissions throughout the Western United States. Brad has sponsored expert witness testimony in over 80 regulatory proceeding encompassing a variety of subject matters, including revenue requirement, regulatory accounting, rate development, and new resource additions. Brad has also assisted his clients through informal regulatory, legislative and energy policy matters. In addition to providing regulatory services, MW Analytics also provides advisory, energy marketing and other energy consulting services.

PRACTICE AREAS

MW Analytics has experience representing customer interests in litigated and informal regulatory proceedings, including the following subject areas:

- Revenue Requirement
- Power Cost Modeling
- Tax Provisions and Tax Reform
- Capital Additions and Forecasting
- Regulatory Accounting
- Depreciation Studies
- Pole Attachments
- Integrated Resource Planning
- Avoided Cost Calculations
- Utility Plant Retirements

EDUCATION AND WORK EXPERIENCE

Brad has a Master of Accounting degree from the University of Utah. After obtaining his master's degree, Brad worked at Deloitte Tax in San Jose, California, where he was responsible for preparing corporate tax returns for multinational corporate clients and partnership returns for hedge fund clients. Brad was later promoted to a Tax Senior position in a national tax practice specializing research and development tax credit studies. Following Deloitte, Brad worked at PacifiCorp Energy, as an analyst involved in power cost modeling and forecasting. At PacifiCorp Brad was responsible for preparing power cost forecasts and supporting testimony for regulatory filings, preparing annual power cost deferral filings, and developing qualifying facility avoided cost calculations.

REGULATORY APPEARANCES

Brad has sponsored expert witness testimony in the following regulatory proceedings:

Docket	Party	Topics
In re CascadeNatural Gas Corporation, Request for a General Rate Revision, Wa.UTC Docket No. UG-210755	Alliance of Western Energy Consumers	Revenue Requirement
In re Northwest Natural Gas Company, dba NW Natural, Request for A General Rate Revision, Or.PUC. Docket No. UG 435	Alliance of Western Energy Consumers	Revenue Requirement / Cost of Service
In re Formal Complaint of Tree Top Inc. against Cascade Natural Gas Corporation, Wa.UTC Docket No. UG-210745	Tree Top, Inc.	Overrun Entitlement
In re Northwest Natural Gas Company, dba NW Natural, Request for Approval of an Affiliated Interest Agreement with Lexington Renewables, LLC, Or.PUC. Docket No. UI 451.	Alliance of Western Energy Consumers	Affiliated Interest

Docket	Party	Topics
In re Avista Corporation, Request for a General Rate Revision, Or.PUC Docket No. UG 433	Alliance of Western Energy Consumers	Revenue Requirement / Cost of Service
In re PacifiCorp Power Cost Only Rate Case, Wa.UTC Docket No. UE-210402.	Alliance of Western Energy Consumers	Power Cost Modeling
In re PacifiCorp Limited Issue Rate Filing, Wa.UTC Docket No. UE-210532.	Alliance of Western Energy Consumers	Revenue Requirement / Settlement
In re the Application of Rocky Mountain Power for Authority to Increase Its Rates and Charges in Idaho and Approval of Proposed Electric Service Schedules and Regulations, Id.PUC Case No. PAC-E-21-07.	PacifiCorp Idaho Industrial Customers	Revenue Requirement / Settlement
In re Portland General Electric, Request for a General Rate Revision, Or.PUC Docket No. UE 394.	Alliance of Western Energy Consumers	Power Cost Modeling
In re Joint Application of Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy for approval of their Economic Recovery Transportation Electrification Plan for the period 2022-2024, PUC Nv. Docket No. 21-09004	Nevada Resort Association	Transportation Electrification
In re PacifiCorp, dba Pacific Power, 2020 Power Cost Adjustment Mechanism, Or.PUC Docket No. UE 392.	Alliance of Western Energy Consumers	Power Cost Deferral
In re the Application of Rocky Mountain Power for Authority to Decrease Current Rates by $14.9 Million to Refund Deferred Net Power Costs Under Tariff Schedule 95 Energy Cost Adjustment Mechanism and to Decrease Current Rates by $166 Thousand Under Tariff Schedule 93, REC and SO2 Revenue Adjustment Mechanism, Wy.PSC Docket No. 20000-599-EM-21.	Wyoming Industrial Energy Consumers	Power Cost Deferral
In re Portland General Electric 2021 Annual Update Tariff Schedule 125, Or. PUC Docket No. UE 391.	Alliance of Western Energy Consumers	Power Cost Modeling
In re Joint Application of Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy for approval of a regulatory asset account to recover costs relating to the development and implementation of their Joint Natural Disaster Protection Plan, PUC NV. Docket No. 21-03004.	Wynn Las Vegas, LLC; Smart Energy Alliance	Single-Issue Rate Filing
In re PacifiCorp d.b.a. Pacific Power, 2022 Transition Adjustment Mechanism, Or.PUC Docket No. UE 390.	Alliance of Western Energy Consumers	Power Cost Modeling
In re Avista 2020 General Rate Case, Wa.U.T.C. Docket No. UE-200900 (Cons.).	Alliance of Western Energy Consumers	Revenue Requirement
In re NV Energy's Fourth Amendment to Its 2018 Joint Integrated Resource Plan, PUC Nv. Docket No 20-07023.	Wynn Las Vegas, LLC; Smart Energy Alliance	Transmission Planning
In Re Cascade Natural Gas Corporation, 2020 General Rate Case, Wa.U.T.C. Docket No. UG-200568	Alliance of Western Energy Consumers	Revenue Requirement
In re Cascade Natural Gas Corporation, Petition to File Depreciation Study, Or.PUC Docket No. UM 2073	Alliance of Western Energy Consumers	Depreciation Rates
In re the Application of Rocky Mountain Power for Authority to Increase Current Rates By $7.4 Million to Recover Deferred Net Power Costs Under Tariff Schedule 95 Energy Cost Adjustment Mechanism and to Decrease Current Rates by $604 Thousand Under Tariff Schedule 93, Rec and So2 Revenue Adjustment Mechanism, Wy.PSC Docket No. 20000-582-EM-20	Wyoming Industrial Energy Consumers	Power Cost Deferral
In re the Complaint of Willamette Falls Paper Company and West Linn Paper Company against Portland General Electric Company, Or.PUC Docket No. UM 2107	Willamette Falls Paper Company	Consumer Direct Access, Tariff Dispute
In re The Application of Rocky Mountain Power for Authority to Increase its Retail Electric Service Rates by Approximately $7.1 Million Per Year or 1.1 Percent, to Revise the Energy Cost Adjustment Mechanism, and to	Wyoming Industrial Energy Consumers	Power Cost Modeling

Docket	Party	Topics
Discontinue Operations at Cholla Unit 4, Wy.PSC Docket No. 2000-578-ER-20		
Avista Corporation 2021 General Rate Case, Or.PUC Docket No. UG 389	Alliance of Western Energy Consumers	Revenue Requirement, Rate Design
In re NW Natural Request for a General Rate Revision, Or.PUC Docket No. UG 388.	Alliance of Western Energy Consumers	Revenue Requirement, Rate Design
In re PacifiCorp, Request to Initiate an Investigation of Multi-Jurisdictional Issues and Approve an Inter-Jurisdictional Cost Allocation Protocol, Or.PUC, UM 1050.	Alliance of Western Energy Consumers	Jurisdictional Allocation
In re Puget Sound Energy 2019 General Rate Case, Wa.UTC Docket No. UE 190529.	Alliance of Western Energy Consumers	Revenue Requirement, Coal Retirement Costs
Avista Corporation 2020 General Rate Case, Wa.UTC Docket No. UE-190334 (Cons.)	Alliance of Western Energy Consumers	Revenue Requirement, Rate Design
In re Cascade Natural Gas Corporation Application for Approval of a Safety Cost Recovery Mechanism, Or. PUC Docket No. UM 2026.	Alliance of Western Energy Consumers	Ratemaking Policy
In re Avista Corporation, Request for a General Rate Revision, Or.PUC Docket No. UG 366.	Alliance of Western Energy Consumers	Revenue Requirement, Rate Design
In re Portland General Electric, 2020 Annual Update Tariff (Schedule 125), Or.PUC Docket No UE 359.	Alliance of Western Energy Consumers	Power Cost Modeling
In re PacifiCorp 2020 Transition Adjustment Mechanism, Or.PUC Docket No. UE 356.	Alliance of Western Energy Consumers	Power Cost Modeling
In re PacifiCorp 2020 Renewable Adjustment Clause, Or.PUC Docket No. UE 352.	Alliance of Western Energy Consumers	Single-Issue Rate Filing
2020 Joint Power and Transmission Rate Proceeding, Bonneville Power Administration, Case No. BP-20.	Alliance of Western Energy Consumers	Revenue Requirement, Policy
In the Matter of the Application of MSG Las Vegas, LLC for a Proposed Transaction with a Provider of New Electric Resources, PUC Nv. Docket No. 18-10034	Madison Square Garden	Customer Direct Access
Puget Sound Energy 2018 Expedited Rate Filing, Wa.UTC Dockets UE-180899/UG-180900 (Cons.).	Alliance of Western Energy Consumers	Revenue Requirement, Settlement
Georgia Pacific Gypsum LLC's Application to Purchase Energy, Capacity, and/or Ancillary Services from a Provider of New Electric Resources, PUC Nv. Docket No. 18-09015.	Georgia Pacific	Customer Direct Access
Joint Application of Nevada Power Company d/b/a NV Energy for approval of their 2018-2038 Triennial Integrated Resource Plan and 2019-2021 Energy Supply Plan, PUCN Docket No. 18-06003.	Smart Energy Alliance	Resource Planning
In re Cascade Natural Gas Corporation Request for a General Rate Revision, Or.PUC, Docket No. UE 347.	Alliance of Western Energy Consumers	Revenue Requirement, Rate Design
In re Portland General Electric Company Request for a General Rate Revision, Or.PUC Docket No UE 335.	Alliance of Western Energy Consumers	Revenue Requirement, Rate Design
In re Northwest Natural Gas Company, dba NW Natural, Request for a General Rate Revision, Or.PUC Docket No. UG 344.	Alliance of Western Energy Consumers	Revenue Requirement, Rate Design
In re Cascade Natural Gas Corporation Request for a General Rate Revision, Wa.UTC, Docket No. UE-170929.	Northwest Industrial Gas Users	Revenue Requirement, Rate Design
In the Matter of Hydro One Limited, Application for Authorization to Exercise Substantial Influence over the Policies and Actions of Avista Corporation, Or.PUC, Docket No. UM 1897.	Alliance of Western Energy Consumers	Merger

Docket	Party	Topics
Application of Rocky Mountain Power for Approval of a Significant Energy Resource Decision and Voluntary Request for Approval of Resource Decision, Ut.PSC Docket No. 17-035-40	Utah Industrial Energy Consumers, & Utah Associated Energy Users	New Resource Addition
In re PacifiCorp, dba Rocky Mountain Power, for a CPCN and Binding Ratemaking Treatment for New Wind and Transmission Facilities, Id.PUC Case No. PAC-E-17-07	PacifiCorp Idaho Industrial Customers	New Resource Addition
In re PacifiCorp, dba Pacific Power, 2016 Power Cost Adjustment Mechanism, Or.PUC, Docket No. UE 327.	Alliance of Western Energy Consumers	Power Cost Deferral
In re PacifiCorp 2016 Power Cost Adjustment Mechanism, Wa.UTC Docket No. UE-170717	Boise Whitepaper, LLC	Power Cost Deferral
In re Avista Corporation 2018 General Rate Case, Wa.UTC Dockets UE-170485 and UG-170486 (Consolidated).	Industrial Customers of Northwest Utilities, & Northwest Industrial Gas Users	Revenue Requirement, Rate Design
Application of Nevada Power Company d/b/a NV Energy for authority to adjust its annual revenue requirement for general rates charged to all classes of electric customers and for relief properly related thereto, PUCN. Docket No. 17-06003.	Smart Energy Alliance	Revenue Requirement
In re the Application of Rocky Mountain Power for Authority to Decrease Current Rates by $15.7 Million to Refund Deferred Net Power Costs Under Tariff Schedule 95 Energy Cost Adjustment Mechanism and to Decrease Current Rates By $528 Thousand Under Tariff Schedule 93, REC and SO2 Revenue Adjustment Mechanism, Wy. PSC, Docket No. 20000-514-EA-17 (Record No. 14696).	Wyoming Industrial Energy Consumers	Power Cost Deferral
In re the 2018 General Rate Case of Puget Sound Energy, Wa.UTC, Docket No. UE-170033 (Cons.).	Industrial Customers of Northwest Utilities, & Northwest Industrial Gas Users	Revenue Requirement, Rate Design
In re PacifiCorp, dba Pacific Power, 2018 Transition Adjustment Mechanism, Or.PUC, Docket No. UE 323.	Industrial Customers of Northwest Utilities	Power Cost Modeling
In re Portland General Electric Company, Request for a General Rate Revision, Or.PUC, Docket No. UE 319.	Industrial Customers of Northwest Utilities	Revenue Requirement, Rate Design
In re Portland General Electric Company, Application for Transportation Electrification Programs, Or.PUC, UM 1811.	Industrial Customers of Northwest Utilities	Electric Vehicle Charging
In re Pacific Power & Light Company, Application for Transportation Electrification Programs, Or.PUC, Docket No. UM 1810.	Industrial Customers of Northwest Utilities	Single-issue Ratemaking
In re the Public Utility Commission of Oregon, Investigation to Examine PacifiCorp, dba Pacific Power's Non-Standard Avoided Cost Pricing, Or.PUC, Docket No. UM 1802.	Industrial Customers of Northwest Utilities	Qualifying Facilities
In re Pacific Power & Light Co., Revisions to Tariff WN U-75, Advice No. 16-05, to modify the Company's existing tariffs governing permanent disconnection and removal procedures, Wa.UTC, Docket No. UE-161204.	Boise Whitepaper, LLC	Customer Direct Access
In re Puget Sound Energy's Revisions to Tariff WN U-60, Adding Schedule 451, Implementing a New Retail Wheeling Service, Wa.UTC, Docket No. UE-161123.	Industrial Customers of Northwest Utilities	Customer Direct Access
2018 Joint Power and Transmission Rate Proceeding, Bonneville Power Administration, Case No. BP-18.	Industrial Customers of Northwest Utilities	Revenue Requirement, Policy
In re Portland General Electric Company Application for Approval of Sale of Harborton Restoration Project Property, Or.PUC, Docket No. UP 334 (Cons.).	Industrial Customers of Northwest Utilities	Environmental Deferral

Docket	Party	Topics
In re An Investigation of Policies Related to Renewable Distributed Electric Generation, Ar.PSC, Matter No. 16-028-U.	Arkansas Electric Energy Consumers	Net Metering
In re Net Metering and the Implementation of Act 827 of 2015, Ar.PSC, Matter No. 16-027-R.	Arkansas Electric Energy Consumers	Net Metering
In re the Application of Rocky Mountain Power for Approval of the 2016 Energy Balancing Account, Ut.PSC, Docket No. 16-035-01	Utah Associated Energy Users	Power Cost Deferral
In re Avista Corporation Request for a General Rate Revision, Wa.UTC, Docket No. UE-160228 (Cons.).	Industrial Customers of Northwest Utilities, & Northwest Industrial Gas Users	Revenue Requirement, Rate Design
In re the Application of Rocky Mountain Power to Decrease Current Rates by $2.7 Million to Recover Deferred Net Power Costs Pursuant to Tariff Schedule 95 and to Increase Rates by $50 Thousand Pursuant to Tariff Schedule 93, Wy.PSC, Docket No. 20000-292-EA-16.	Wyoming Industrial Energy Consumers	Power Cost Deferral
In re PacifiCorp, dba Pacific Power, 2017 Transition Adjustment Mechanism, Or.PUC, Docket No. UE 307.	Industrial Customers of Northwest Utilities	Power Cost Modeling
In re Portland General Electric Company, 2017 Annual Power Cost Update Tariff (Schedule 125), Or.PUC, Docket No. UE 308.	Industrial Customers of Northwest Utilities	Power Cost Modeling
In re Pacific Power & Light Company, General rate increase for electric services, Wa.UTC, Docket No. UE-152253.	Boise Whitepaper, LLC	Revenue Requirement, Rate Design
In The Matter of the Application of Rocky Mountain Power for Authority of a General Rate Increase in Its Retail Electric Utility Service Rates in Wyoming of $32.4 Million Per Year or 4.5 Percent, Wy.PSC, Docket No. 20000-469-ER-15.	Wyoming Industrial Energy Consumers	Power Cost Modeling
In re Avista Corporation, General Rate Increase for Electric Services, Wa.UTC, Docket No. UE-150204.	Industrial Customers of Northwest Utilities	Revenue Requirement, Rate Design
In re the Application of Rocky Mountain Power to Decrease Rates by $17.6 Million to Recover Deferred Net Power Costs Pursuant to Tariff Schedule 95 to Decrease Rates by $4.7 Million Pursuant to Tariff Schedule 93, Wy.PSC, Docket No. 20000-472-EA-15.	Wyoming Industrial Energy Consumers	Power Cost Deferral
Formal complaint of The Walla Walla Country Club against Pacific Power & Light Company for refusal to provide disconnection under Commission-approved terms and fees, as mandated under Company tariff rules, Wa.UTC, Docket No. UE-143932.	Columbia Rural Electric Association	Customer Direct Access / Customer Choice
In re PacifiCorp, dba Pacific Power, 2016 Transition Adjustment Mechanism, Or.PUC, Docket No. UE 296.	Industrial Customers of Northwest Utilities	Power Cost Modeling
In re Portland General Electric Company, Request for a General Rate Revision, Or.PUC, Docket No. UE 294.	Industrial Customers of Northwest Utilities	Revenue Requirement, Rate Design
In re Portland General Electric Company and PacifiCorp dba Pacific Power, Request for Generic Power Cost Adjustment Mechanism Investigation, Or.PUC, Docket No. UM 1662.	Industrial Customers of Northwest Utilities	Power Cost Deferral
In re PacifiCorp, dba Pacific Power, Application for Approval of Deer Creek Mine Transaction, Or.PUC, Docket No. UM 1712.	Industrial Customers of Northwest Utilities	Single-issue Ratemaking
In re Public Utility Commission of Oregon, Investigation to Explore Issues Related to a Renewable Generator's Contribution to Capacity, Or.PUC, Docket No. UM 1719.	Industrial Customers of Northwest Utilities	Resource Planning
In re Portland General Electric Company, Application for Deferral Accounting of Excess Pension Costs and Carrying Costs on Cash Contributions, Or.PUC, Docket No. UM 1623.	Industrial Customers of Northwest Utilities	Single-issue Ratemaking

Docket	Party	Topics
2016 Joint Power and Transmission Rate Proceeding, Bonneville Power Administration, Case No. BP-16.	Industrial Customers of Northwest Utilities	Revenue Requirement, Policy
In re Puget Sound Energy, Petition to Update Methodologies Used to Allocate Electric Cost of Service and for Electric Rate Design Purposes, Wa.UTC, Docket No. UE-141368.	Industrial Customers of Northwest Utilities	Cost of Service
In re Pacific Power & Light Company, Request for a General Rate Revision Resulting in an Overall Price Change of 8.5 Percent, or $27.2 Million, Wa.UTC, Docket No. UE-140762.	Boise Whitepaper, LLC	Revenue Requirement, Rate Design
In re Puget Sound Energy, Revises the Power Cost Rate in WN U-60, Tariff G, Schedule 95, to reflect a decrease of $9,554,847 in the Company's overall normalized power supply costs, Wa.UTC, Docket No. UE-141141.	Industrial Customers of Northwest Utilities	Power Cost Modeling
In re the Application of Rocky Mountain Power for Authority to Increase Its Retail Electric Utility Service Rates in Wyoming Approximately $36.1 Million Per Year or 5.3 Percent, Wy.PSC, Docket No. 20000-446-ER-14.	Wyoming Industrial Energy Consumers	Power Cost Modeling
In re Avista Corporation, General Rate Increase for Electric Services, RE, Tariff WN U-28, Which Proposes an Overall Net Electric Billed Increase of 5.5 Percent Effective January 1, 2015, Wa.UTC, Docket No. UE-140188.	Industrial Customers of Northwest Utilities	Revenue Requirement, Rate Design, Power Costs
In re PacifiCorp, dba Pacific Power, Application for Deferred Accounting and Prudence Determination Associated with the Energy Imbalance Market, Or.PUC, Docket No. UM 1689.	Industrial Customers of Northwest Utilities	Single-issue Ratemaking
In re PacifiCorp, dba Pacific Power, 2015 Transition Adjustment Mechanism, Or.PUC, Docket No. UE 287.	Industrial Customers of Northwest Utilities	Power Cost Modeling
In re Portland General Electric Company, Request for a General Rate Revision, Or.PUC, Docket No. UE 283.	Industrial Customers of Northwest Utilities	Revenue Requirement, Rate Design
In re Portland General Electric Company's Net Variable Power Costs (NVPC) and Annual Power Cost Update (APCU), Or.PUC, Docket No. UE 286.	Industrial Customers of Northwest Utilities	Power Cost Modeling
In re Portland General Electric Company 2014 Schedule 145 Boardman Power Plant Operating Adjustment, Or.PUC, Docket No. UE 281.	Industrial Customers of Northwest Utilities	Coal Retirement
In re PacifiCorp, dba Pacific Power, Transition Adjustment, Five-Year Cost of Service Opt-Out (adopting testimony of Donald W. Schoenbeck), Or.PUC, Docket No. UE 267.	Industrial Customers of Northwest Utilities	Customer Direct Access

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UE 400

In the Matter of	)
	)
PacifiCorp, dba Pacific Power,	)
	)
2023 Transition Adjustment Mechanism.	)
	)

EXHIBIT AWEC/102

PACIFICORP RESPONSES TO DISCOVERY REQUESTS

(REDACTED)

UE 400 / PacifiCorp
April 14, 2022
AWEC Data Request 010

AWEC Data Request 010

Reference work paper "Aurora GN Transmission Links CONF", tab "1 Transmission Links": Please provide work papers, including all supporting historical transaction data, used to establish short-term and non-firm transmission links and link capacity input into the AURORA model.

Response to AWEC Data Request 010

Please refer to Confidential Attachment AWEC 010 which provides data relating to short-term (ST) and non-firm (NF) transmission links.

For transmission link capacities other than those mentioned above, the Company uses values from the Open Access Same-Time Information System (OASIS).

Confidential information is designated as Protected Information under Order No. 16-128 and may only be disclosed to qualified persons as defined in that order.

UE 400 / PacifiCorp
April 14, 2022
AWEC Data Request 014

AWEC Data Request 014

Reference work papers “TAM Allocation - CY 2023 - Initial Filing,” Tab “Summary TAM 2023”, Excel Column “I:” Please provide work papers supporting the derivation of the allocation factors, including load forecasts for each state and each jurisdiction.

Response to AWEC Data Request 014

Please refer to Attachment AWEC 014.

Pro Forma Factors December 31, 2023
Oregon Transition Adjustment Mechanism - December 2023
COINCIDENTAL PEAKS

FORECAST LOADS (CP)

			Non-FERC						FERC	
Month	Day	Time	CA	OR	WA	UT	ID	WY		Total
Jan-23	12	8	148	2,655	838	3,495	469	1,223	33	8,861
Feb-23	7	8	139	2,484	704	3,438	453	1,184	34	8,436
Mar-23	9	8	135	2,379	674	3,295	437	1,167	34	8,120
Apr-23	5	8	117	2,196	576	3,088	426	1,105	34	7,542
May-23	16	16	113	1,917	577	4,075	545	1,095	22	8,344
Jun-23	22	16	129	2,051	684	4,913	769	1,200	34	9,780
Jul-23	17	16	140	2,409	760	5,176	783	1,237	35	10,541
Aug-23	24	16	132	2,474	743	5,033	616	1,202	36	10,236
Sep-23	7	16	116	2,161	660	4,673	556	1,146	36	9,348
Oct-23	2	18	103	1,901	602	3,783	429	1,129	35	7,983
Nov-23	22	18	122	2,196	695	3,730	466	1,236	34	8,479
Dec-23	13	18	136	2,398	726	3,923	494	1,282	36	8,995
			1,531	27,220	8,239	48,623	6,443	14,205	404	106,665

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Adjustments for Curtailments, Buy-Throughs and Load No Longer Served (Reductions to Load)

			Non-FERC						FERC	
Month	Day	Time	CA	OR	WA	UT	ID	WY		Total
Jan-23	12	8	-	-	-	198	-	-	30	228
Feb-23	7	8	-	-	-	201	-	-	32	233
Mar-23	9	8	-	-	-	202	-	-	32	233
Apr-23	5	8	-	-	-	202	-	-	32	234
May-23	16	16	-	-	-	233	-	-	21	254
Jun-23	22	16	-	-	-	359	170	-	31	560
Jul-23	17	16	-	-	-	385	146	-	32	563
Aug-23	24	16	-	-	-	305	79	-	33	417
Sep-23	7	16	-	-	-	352	-	-	34	386
Oct-23	2	18	-	-	-	220	-	-	33	252
Nov-23	22	18	-	-	-	222	-	-	32	255
Dec-23	13	18	-	-	-	304	-	-	33	337
			-	-	-	3,182	395	-	376	3,953

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COINCIDENTAL PEAK SERVED FROM COMPANY RESOURCES

			Non-FERC						FERC	
Month	Day	Time	CA	OR	WA	UT	ID	WY		Total
Jan-23	12	8	148	2,655	838	3,297	469	1,223	3	8,633
Feb-23	7	8	139	2,484	704	3,237	453	1,184	3	8,204
Mar-23	9	8	135	2,379	674	3,093	437	1,167	2	7,886
Apr-23	5	8	117	2,196	576	2,886	426	1,105	2	7,308
May-23	16	16	113	1,917	577	3,842	545	1,095	1	8,090
Jun-23	22	16	129	2,051	684	4,554	599	1,200	2	9,219
Jul-23	17	16	140	2,409	760	4,791	637	1,237	3	9,978
Aug-23	24	16	132	2,474	743	4,728	537	1,202	3	9,818
Sep-23	7	16	116	2,161	660	4,321	556	1,146	2	8,962
Oct-23	2	18	103	1,901	602	3,563	429	1,129	2	7,730
Nov-23	22	18	122	2,196	695	3,508	466	1,236	2	8,225
Dec-23	13	18	136	2,398	726	3,619	494	1,282	3	8,658
			1,531	27,220	8,239	45,441	6,048	14,205	29	102,712

+ plus

Adjustments for Ancillary Services Contracts including Reserves and Direct Access (Additions to Load)

			Non-FERC						FERC	
Month	Day	Time	CA	OR	WA	UT	ID	WY		Total
Jan-23	12	8	-	-	-	30	-	-	-	30
Feb-23	7	8	-	-	-	32	-	-	-	32
Mar-23	9	8	-	-	-	32	-	-	-	32
Apr-23	5	8	-	-	-	32	-	-	-	32
May-23	16	16	-	-	-	21	-	-	-	21
Jun-23	22	16	-	-	-	31	-	-	-	31
Jul-23	17	16	-	-	-	32	-	-	-	32
Aug-23	24	16	-	-	-	33	-	-	-	33
Sep-23	7	16	-	-	-	34	-	-	-	34
Oct-23	2	18	-	-	-	33	-	-	-	33
Nov-23	22	18	-	-	-	32	-	-	-	32
Dec-23	13	18	-	-	-	33	-	-	-	33
			-	-	-	376	-	-	-	376

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LOADS FOR JURISDICTIONAL ALLOCATION (CP)

			Non-FERC						FERC	
Month	Day	Time	CA	OR	WA	UT	ID	WY		Total
Jan-23	12	8	148	2,655	838	3,327	469	1,223	3	8,663
Feb-23	7	8	139	2,484	704	3,269	453	1,184	3	8,235
Mar-23	9	8	135	2,379	674	3,125	437	1,167	2	7,918
Apr-23	5	8	117	2,196	576	2,919	426	1,105	2	7,341
May-23	16	16	113	1,917	577	3,863	545	1,095	1	8,112
Jun-23	22	16	129	2,051	684	4,585	599	1,200	2	9,251
Jul-23	17	16	140	2,409	760	4,823	637	1,237	3	10,010
Aug-23	24	16	132	2,474	743	4,761	537	1,202	3	9,852
Sep-23	7	16	116	2,161	660	4,355	556	1,146	2	8,996
Oct-23	2	18	103	1,901	602	3,596	429	1,129	2	7,763
Nov-23	22	18	122	2,196	695	3,540	466	1,236	2	8,257
Dec-23	13	18	136	2,398	726	3,652	494	1,282	3	8,691
			1,531	27,220	8,239	45,816	6,048	14,205	29	103,088
System Capacity			1.485%	26.404%	7.993%	44.444%	5.867%	13.780%	0.028%	100.000%
System Generation			1.467%	$\boxed{26.070\%}$	7.839%	44.395%	6.006%	14.193%	0.029%	100.000%

Pro Forma Factors December 31, 2023
Oregon Transition Adjustment Mechanism - December 2023
ENERGY

FORECAST LOADS (MWh)

Year	Month	CA	OR	WA	UT	ID	WY	FERC	Total
		Non-FERC						FERC	
2023	Jan	78,390	1,438,180	438,220	2,298,190	309,560	813,290	24,441	5,400,271
2023	Feb	67,180	1,257,950	370,680	2,036,940	270,310	736,210	23,009	4,762,279
2023	Mar	68,700	1,298,140	362,940	2,133,840	281,240	802,650	24,250	4,971,760
2023	Apr	66,270	1,190,510	327,090	2,052,730	277,990	762,420	24,189	4,701,199
2023	May	71,900	1,181,490	334,590	2,163,970	335,990	765,160	24,073	4,877,173
2023	Jun	75,680	1,179,260	343,070	2,406,360	416,930	783,120	23,154	5,227,574
2023	Jul	82,380	1,329,280	397,920	2,803,180	489,470	785,910	25,094	5,913,234
2023	Aug	78,240	1,311,840	392,590	2,740,080	393,900	820,570	25,399	5,762,619
2023	Sep	67,140	1,173,020	350,790	2,326,440	310,150	759,100	25,045	5,011,685
2023	Oct	62,970	1,187,200	361,320	2,185,070	277,630	780,910	25,385	4,880,485
2023	Nov	66,800	1,289,570	385,440	2,192,300	258,140	779,820	24,930	4,997,000
2023	Dec	77,510	1,474,010	441,550	2,373,950	302,220	837,470	26,141	5,532,851
		863,160	15,310,450	4,506,200	27,713,050	3,923,530	9,426,630	295,110	62,038,130

- (less)

Adjustments for Curtailments, Buy-Throughs and Load No Longer Served (Reductions to Load)

Year	Month	CA	OR	WA	UT	ID	WY	FERC	Total
		Non-FERC						FERC	
2023	Jan				55,864		-	22,398	78,262
2023	Feb				48,407		-	21,260	69,667
2023	Mar				76,018		-	22,559	98,577
2023	Apr				83,808		-	22,741	106,548
2023	May				81,921		-	22,610	104,531
2023	Jun				80,771		-	21,664	102,435
2023	Jul				85,708		-	23,098	108,807
2023	Aug				92,440		-	23,408	115,848
2023	Sep				94,556		-	23,468	118,024
2023	Oct				96,135		-	23,815	119,950
2023	Nov				96,195		-	23,240	119,434
2023	Dec				70,963		-	24,079	95,041
		-	-	-	962,785	-	-	274,339	1,237,124

= equals

LOADS SERVED FROM COMPANY RESOURCES (NPC)

Year	Month	CA	OR	WA	UT	ID	WY	FERC	Total
		Non-FERC						FERC	
2023	Jan	78,390	1,438,180	438,220	2,242,326	309,560	813,290	2,042	5,322,009
2023	Feb	67,180	1,257,950	370,680	1,988,533	270,310	736,210	1,750	4,692,613
2023	Mar	68,700	1,298,140	362,940	2,057,822	281,240	802,650	1,691	4,873,183
2023	Apr	66,270	1,190,510	327,090	1,968,922	277,990	762,420	1,448	4,594,650
2023	May	71,900	1,181,490	334,590	2,082,049	335,990	765,160	1,462	4,772,642
2023	Jun	75,680	1,179,260	343,070	2,325,589	416,930	783,120	1,490	5,125,139
2023	Jul	82,380	1,329,280	397,920	2,717,472	489,470	785,910	1,996	5,804,428
2023	Aug	78,240	1,311,840	392,590	2,647,640	393,900	820,570	1,991	5,646,771
2023	Sep	67,140	1,173,020	350,790	2,231,884	310,150	759,100	1,577	4,893,661
2023	Oct	62,970	1,187,200	361,320	2,088,935	277,630	780,910	1,570	4,760,535
2023	Nov	66,800	1,289,570	385,440	2,096,105	258,140	779,820	1,690	4,877,566
2023	Dec	77,510	1,474,010	441,550	2,302,987	302,220	837,470	2,062	5,437,810
		863,160	15,310,450	4,506,200	26,750,265	3,923,530	9,426,630	20,771	60,801,006

+ plus

Add: Resolute NTUA (UT) - Grossed up for Line Losses

Year	Month	CA	OR	WA	UT	ID	WY	FERC	Total
		Non-FERC						FERC	
2023	Jan				22,398		-		22,398
2023	Feb				21,260		-		21,260
2023	Mar				22,559		-		22,559
2023	Apr				22,741		-		22,741
2023	May				22,610		-		22,610
2023	Jun				21,664		-		21,664
2023	Jul				23,098		-		23,098
2023	Aug				23,408		-		23,408
2023	Sep				23,468		-		23,468
2023	Oct				23,815		-		23,815
2023	Nov				23,240		-		23,240
2023	Dec				24,079		-		24,079
		-	-	-	274,339	-	-	-	274,339

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LOADS FOR JURISDICTIONAL ALLOCATION (MWh)

Year	Month	CA	OR	WA	UT	ID	WY	FERC	Total
		Non-FERC						FERC	
2023	Jan	78,390	1,438,180	438,220	2,264,725	309,560	813,290	2,042	5,344,407
2023	Feb	67,180	1,257,950	370,680	2,009,792	270,310	736,210	1,750	4,713,872
2023	Mar	68,700	1,298,140	362,940	2,080,381	281,240	802,650	1,691	4,895,742
2023	Apr	66,270	1,190,510	327,090	1,991,663	277,990	762,420	1,448	4,617,391
2023	May	71,900	1,181,490	334,590	2,104,660	335,990	765,160	1,462	4,795,252
2023	Jun	75,680	1,179,260	343,070	2,347,253	416,930	783,120	1,490	5,146,803
2023	Jul	82,380	1,329,280	397,920	2,740,570	489,470	785,910	1,996	5,827,526
2023	Aug	78,240	1,311,840	392,590	2,671,048	393,900	820,570	1,991	5,670,179
2023	Sep	67,140	1,173,020	350,790	2,255,352	310,150	759,100	1,577	4,917,129
2023	Oct	62,970	1,187,200	361,320	2,112,749	277,630	780,910	1,570	4,784,349
2023	Nov	66,800	1,289,570	385,440	2,119,345	258,140	779,820	1,690	4,900,805
2023	Dec	77,510	1,474,010	441,550	2,327,066	302,220	837,470	2,062	5,461,888
		863,160	15,310,450	4,506,200	27,024,604	3,923,530	9,426,630	20,771	61,075,345
System Energy		1.413%	25.068%	7.378%	44.248%	6.424%	15.434%	0.034%	

UE 400 / PacifiCorp
April 14, 2022
AWEC Data Request 020

AWEC Data Request 020

Reference work paper "ORTAM23 NPC CONF: Tab "UT Solar Adjustment" Cells "A20:M26": Please provide work papers supporting the hardcoded values in the referenced cells.

Response to AWEC Data Request 020

PacifiCorp objects to this request as outside the scope of the transition adjustment mechanism (TAM) and not reasonably calculated to lead to the discovery of admissible evidence. Without waiving the foregoing objection, PacifiCorp responds as follows:

In the course of responding to this data request, PacifiCorp identified an error. The generation data for the solar resources in cell "D2:G13" has been identified as incorrect. These cells should be linked to the "NPC Summary" tab of the net power costs (NPC) report. Additionally, this leads to incorrect calculation of costs in referenced cells "A20:M26".

PacifiCorp will make this correction in the June reply update.

UE 400 / PacifiCorp
April 14, 2022
AWEC Data Request 022

AWEC Data Request 022

Reference Exhibit PAC/102, Wilding/2: Please provide all economic analyses and internal memoranda supporting entering into the power purchase agreements titled Appaloosa 1A Solar and Appaloosa 1B Solar.

Response to AWEC Data Request 022

Referencing the power purchase agreements (PPA) executed with Appaloosa Solar I, LLC for the Appaloosa I-A and Appaloosa I-B solar projects, the Company did not complete any economic analysis for these solar projects because 100 percent of the costs associated with the PPAs are passed through to an individual customer under Utah Electric Service Schedule 34. Among other things, the Schedule 34 agreements contains provisions that obligate the customer to "continue to pay all of the costs of the renewable energy resource(s) acquired by the Company on the Customer's behalf in the event the Customer contract is terminated early and a cost obligation related to the renewable energy resource(s) continues beyond the termination" of the Schedule 34 agreement.

A copy of Utah Electric Service Schedule 34 can be accessed by utilizing the following website link:

034 Renewable Energy Purchases for Qualified Customers 5000kW and Over.pdf (rockymountainpower.net)

UE 400 / PacifiCorp
April 14, 2022
AWEC Data Request 023

AWEC Data Request 023

Reference Exhibit PAC/102, Wilding/1: Please provide a copy of the power sales agreement, and any other amendments or formal documentation supporting the agreement, associated with the PSCo Sale line item.

Response to AWEC Data Request 023

Please refer to Confidential Attachment AWEC 023 which provides a copy of the contract (Physical Transaction Confirmation) between PacifiCorp and the Public Service Company of Colorado (PSCo).

Confidential information is designated as Protected Information under Order No. 16-128 and may only be disclosed to qualified persons as defined in that order.

UE 400 / PacifiCorp
April 14, 2022
AWEC Data Request 024

AWEC Data Request 024

Reference Exhibit PAC/102, Wilding/1: Please provide all economic analysis and internal memoranda supporting the decision to enter into the PSCo Sale agreement identified on the referenced exhibit.

Response to AWEC Data Request 024

Please refer to Confidential Attachment AWEC 024.

Confidential information is designated as Protected Information under Order No. 16-128 and may only be disclosed to qualified persons as defined in that order.

[redacted]

PACIFICORP
A BERKSHIRE HATHAWAY ENERGY COMPANY

[redacted]

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A BERKSHIRE HATHAWAY ENERGY COMPANY

[redacted]

PACIFICORP
A BERKSHIRE HATHAWAY ENERGY COMPANY

[redacted]

UE 400 / PacifiCorp
May 16, 2022
AWEC Data Request 035

AWEC Data Request 035

Reference PacifiCorp's response to AWEC Data Request 22: Please explain how the load associated with customer's participation in the Utah Schedule 35 program is considered when calculating jurisdictional allocation factors.

Response to AWEC Data Request 035

The Company advises that there is not a "Utah Schedule 35" at this current time among the rate schedules offered to Rocky Mountain Power's (RMP) customers in Utah. The Company assumes that the reference to "Utah Schedule 35" was intended to be a reference to Utah Schedule 34 (Renewable Energy Purchases for Qualified Customers – 5,000 kW and Over). Based on the foregoing assumption, the Company responds as follows:

The load associated with a customer's participation in Utah Schedule 34 is treated consistent with the customer agreement and as follows for the calculation of jurisdictional allocation factors:

Energy: energy supplied by the renewable resources is excluded from jurisdictional allocation factors. Any energy supplied by PacifiCorp is included in the jurisdictional allocation factors.

Capacity (coincident peak (CP)): capacity served by the renewable resource is excluded for the monthly renewable generation, not to exceed the customer's demand. Any capacity supplied by PacifiCorp is included in the monthly CP.

UE 400 / PacifiCorp
May 16, 2022
AWEC Data Request 036

AWEC Data Request 036

Reference PacifiCorp's response to AWEC Data Request 22: Please identify the monthly load and CP demand for aggregate customers participating in Schedule 35 for the test period.

Response to AWEC Data Request 036

PacifiCorp objects to this request as outside the scope of this proceeding, requesting customer specific information, and not reasonably calculated to lead to the discovery of admissible information. Without waiving the foregoing objection, PacifiCorp responds as follows:

The Company advises that there is not a "Utah Schedule 35" at this current time among the rate schedules offered to Rocky Mountain Power's (RMP) customers in Utah. The Company assumes that the reference to "Utah Schedule 35" was intended to be a reference to Utah Schedule 34 (Renewable Energy Purchases for Qualified Customers – 5,000 kW and Over). Based on the following assumption, the Company responds as follows:

At this time, there is only one customer on Utah Schedule 34 during the test period. The monthly load and coincident peak (CP) demand is confidential customer-specific information. The Company is generally unable to provide customer-specific information without the explicit permission of the customer. After discussions with that customer, PacifiCorp is declining to provide this customer-specific information.

UE 400 / PacifiCorp
May 16, 2022
AWEC Data Request 037

AWEC Data Request 037

Reference PacifiCorp's response to AWEC Data Request 14, Attachment AWEC 014: Please provide hourly data used to derive each of the values in the referenced work paper.

Response to AWEC Data Request 037

Please refer to Confidential Attachment AWEC 037-1 which provides the hourly load data used to derive the forecast load coincident peaks (CP) supporting the Company's response to AWEC Data Request 014.

Please refer to Confidential Attachment AWEC 037-2 which provides the monthly load data used to derive the adjustments for curtailments, buy-throughs and load no longer served supporting the Company's response to AWEC Data Request 014.

Confidential information is designated as Protected Information under Order No. 16-128 and may only be disclosed to qualified persons as defined in that order.

[redacted]

[redacted]

UE 400 / PacifiCorp
May 16, 2022
AWEC Data Request 038

AWEC Data Request 038

> Reference PacifiCorp's response to AWEC Data Request 14, Attachment AWEC 014, Tab "Peak Load," cells "H24:H35": Please provide an explanation for why the demand values identified in the referenced cell are being subtracted from Utah's demand requirements.

Response to AWEC Data Request 038

As defined in the 2020 Protocol, Demand-Side Management Programs:

> Benefits from these programs, in the form of reduced consumption and contribution to Coincident Peak, will be reflected in the Load-Based Dynamic Allocation Factors.

Contracts are to be handled as defined in the 2020 Protocol, Appendix G, Special Contracts without Ancillary Service Contract Attributes:

> When interruptions of a Special Contract customer's service occur, the reduction in load will be reflected in the host jurisdiction's Load-Based Dynamic Allocation Factors.

Utah Schedule 34 load that is not being served by PacifiCorp is being subtracted from the load.

UE 400 / PacifiCorp
May 16, 2022
AWEC Data Request 039

AWEC Data Request 039

Reference PacifiCorp's response to AWEC Data Request 14, Attachment AWEC 014, Tab "Peak Load," cells "H24:H35": Please provide work papers used to support the values in the referenced cells.

Response to AWEC Data Request 039

Please refer to the Company's response to AWEC Data Request 037, specifically Confidential Attachment AWEC 037-2.

UE 400 / PacifiCorp
May 16, 2022
AWEC Data Request 045

AWEC Data Request 045

Reference work paper "TAM Allocation - CY 2023 - Initial Filing," Tab "Oregon Situs - 2023 Initial", Cells "D8:O11": Please provide work papers supporting the situs assignment calculations in each of the referenced cells.

Response to AWEC Data Request 045

Please refer to Confidential Attachment AWEC 045.

Confidential information is designated as Protected Information under Order No. 16-128 and may only be disclosed to qualified persons as defined in that order.

UE 400 / PacifiCorp
May 16, 2022
AWEC Data Request 050

AWEC Data Request 050

Please state the Oregon depreciable life for each of PacifiCorp's coal and gas units, including the month and year of the end-of-life assumption.

Response to AWEC Data Request 050

Please refer to Attachment AWEC 050 which provides the retirement date assumptions included as part of the 2018 Depreciation Study and approved under Docket UM 1968 and Docket UE 374.

Plant	Commercial Operations Date	2018 Depreciation Study Retirement Date	Depreciable Life Span (Years)
Steam Plants			
Blundell 1 (Geothermal)	1984	2037	53
Blundell 2 (Geothermal)	2007	2037	30
Colstrip-3	1984	2027	43
Colstrip-4	1986	2027	41
Craig-1	1980	2025	45
Craig-2	1979	2026	47
Dave Johnston-1	1959	2027	68
Dave Johnston-2	1960	2027	67
Dave Johnston-3	1964	2027	63
Dave Johnston-4	1972	2027	55
Gadsby-1 (Rankine)	1951	2032	81
Gadsby-2 (Rankine)	1952	2032	80
Gadsby-3 (Rankine)	1955	2032	77
Hayden-1	1965	2023	58
Hayden-2	1976	2023	47
Hunter-1	1978	2029	51
Hunter-2	1980	2029	49
Hunter-3	1983	2029	46
Huntington-1	1977	2029	52
Huntington-2	1974	2029	55
Jim Bridger-1	1974	2023	49
Jim Bridger-2	1975	2025	50
Jim Bridger-3	1976	2025	49
Jim Bridger-4	1979	2025	46
Naughton-1	1963	2025	62
Naughton-2	1968	2025	57
Naughton-3	1971	2029	58
Wyodak-1	1978	2029	51
Gas Plants			
Chehalis (CCCT)	2003	2043	40
Currant Creek (CCCT)	2005	2045	40
Gadsby-4,5,6 (CT)	2002	2032	30
Hermiston (CCCT)	1996	2036	40
Lake Side 1 (CCCT)	2007	2047	40
Lake Side 2 (CCCT)	2014	2054	40

UE 400 / PacifiCorp
May 18, 2022
AWEC Data Request 060

AWEC Data Request 060

Reference PAC/200, Owens/22 at 16-18: Please provide all economic analyses, in Excel format with all formulas and links intact, supporting the decision identified with respect to the coal supply at the Hayden Plant.

Confidential Response to AWEC Data Request 060

The Hayden coal supply agreement (CSA) **[CONFIDENTIAL BEGINS]** [redacted] **[CONFIDENTIAL ENDS]** referenced above only gave the plant owners, including PacifiCorp, **[CONFIDENTIAL BEGINS]** [redacted] **[CONFIDENTIAL ENDS]** an economic analysis would have served no meaningful purpose.

Confidential information is designated as Protected Information under Order No. 16-128 and may only be disclosed to qualified persons as defined in that order.

UE 400 / PacifiCorp
May 18, 2022
AWEC Data Request 061

AWEC Data Request 061

Reference PAC/200, Owens/22 at 16-18: Please provide all internal memoranda prepared supporting the decision identified with respect to the coal supply at the Hayden Plant.

Response to AWEC Data Request 061

No internal memoranda were prepared concerning the referenced coal supply. Please refer to the Company's response to AWEC Data Request 60 which provides further details explaining why no internal memoranda was necessary.

UE 400 / PacifiCorp
May 18, 2022
AWEC Data Request 062

AWEC Data Request 062

Please provide detail of each plant addition at the Trapper mine over the period January 1, 2018, through April 30, 2022.

Response to AWEC Data Request 062

This requested information is not available because Trapper mine does not provide PacifiCorp with that level of detail on plant additions.

UE 400 / PacifiCorp
May 18, 2022
AWEC Data Request 063

AWEC Data Request 063

Please provide detail of each forecast plant addition at the Trapper mine over the period January 1, 2022, through December 31, 2022, corresponding to the schedule provided in Schedule 8.2.1 in witness Cheung's workpapers in Docket No. UE 399.

Response to AWEC Data Request 063

This information is not available because Trapper mine does not provide this level of detail to PacifiCorp. Forecasted values for 2022 assumes a flat gross plant balance consistent with continued operations at the plant.

UE 400 / PacifiCorp
May 18, 2022
AWEC Data Request 064

AWEC Data Request 064

Please provide the detailed calculation of depreciation expense at the Trapper mine, including detail of all depreciation parameters used.

Response to AWEC Data Request 064

PacifiCorp does not receive a detailed calculation of the depreciation expense or the detail of all depreciation parameters from the Trapper mine.

UE 400 / PacifiCorp
May 18, 2022
AWEC Data Request 065

AWEC Data Request 065

Please provide a description of how the plant at the Trapper mine is included in rate base

Response to AWEC Data Request 065

PacifiCorp owns a 29.14 percent interest in the Trapper Mine. This investment is accounted for on the Company's books in FERC Account 123.1 (Investment in Subsidiary Company), which is not included in rate base. Accordingly, in Docket No. UE-399, Exhibit PAC/1002/Cheung/200, Adjustment 8.2, Trapper Mine Rate Base, adds PacifiCorp's portion of the Trapper Mine plant investment to rate base. Please note: Trapper Mine rate base is not part of the Transition Adjustment Mechanism (TAM) and is addressed in the Company's general rate case (GRC) proceedings. The adjustment was stipulated to and approved in Docket No.UE-111, and it has been included in all GRC filings since.

UE 400 / PacifiCorp
May 18, 2022
AWEC Data Request 066

AWEC Data Request 066

Please provide any analysis PacifiCorp, and or PacifiCorp's mining partners, has performed to quantify the cost of closing, decommissioning and remediating the Trapper mine.

Response to AWEC Data Request 066

Please refer to the Company's response to AWEC Data Request 056, specifically Confidential Attachment AWEC 056 which provides the Trapper reclamation analysis.

UE 400 / PacifiCorp
May 18, 2022
AWEC Data Request 067

AWEC Data Request 067

Please provide any recommendations submitted to the Oregon Commission between January 1, 2020, and February 1, 2021, regarding the treatment of Hayden Units 1 and 2.

Response to AWEC Data Request 067

PacifiCorp objects to this request as overly broad, ambiguous and not reasonably calculated to lead to the discovery of admissible evidence. Without waiving the foregoing objection, PacifiCorp responds as follows:

It is unclear what is meant by “the treatment of Hayden Units 1 and 2”. For PacifiCorp’s recommendations on future generation portfolios, please refer to the 2021 Integrated Resource Plan (IRP), which is publicly available and can be accessed by utilizing the following PacifiCorp website link:

https://www.pacificorp.com/energy/integrated-resource-plan.html.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UE 400

In the Matter of	)
	)
PacifiCorp, dba Pacific Power,	)
	)
2023 Transition Adjustment Mechanism.	)
	)

EXHIBIT AWEC/103

PRODUCTION TAX CREDIT FORECAST FOR 2023

PTC Inflation Adjustment Factor Calculations

	GDP Implicit Price Deflator						Inflation Adjustment Factor			PTC
Year	**Q1**	**Q2**	**Q3**	**Q4**	**AVG.**	**1992**	**Recalc'd**	**Actual**	**Delta**	**Rate**
1992	119.80	120.60	121.20	121.80	120.90	120.90	1.0000	1.0000	-	1.5
1993	123.30	124.00	124.50	124.90	124.20	120.90	1.0273	1.0273	-	1.5
1994	125.00	125.90	126.50	126.90	126.10	120.90	1.0430	1.0430	-	1.6
1995	106.70	107.30	107.80	108.30	107.50	100.00	1.0750	1.0750	-	1.6
1996	109.00	109.50	109.90	110.30	109.70	100.00	1.0970	1.0970	-	1.6
1997	111.71	112.22	112.62	113.05	112.40	100.00	1.1240	1.1240	-	1.7
1998	112.32	112.56	112.84	113.04	112.69	100.00	1.1269	1.1269	-	1.7
1999	103.83	104.19	104.46	104.98	104.37	91.70	1.1382	1.1382	-	1.7
2000	106.10	106.73	107.15	107.65	106.91	91.84	1.1641	1.1641	-	1.7
2001	108.65	109.21	109.82	109.75	109.36	91.84	1.1908	1.1908	-	1.8
2002	110.14	110.48	110.76	111.21	110.65	91.84	1.2048	1.2048	-	1.8
2003	105.15	105.43	105.85	106.16	105.65	86.39	1.2230	1.2230	-	1.8
2004	107.25	108.09	108.48	109.06	108.22	86.39	1.2528	1.2528	-	1.9
2005	110.91	111.62	112.53	113.49	112.14	86.39	1.2981	1.2981	-	1.9
2006	114.95	115.89	116.42	116.89	116.04	86.39	1.3433	1.3433	-	2.0
2007	118.75	119.52	119.83	120.61	119.68	86.39	1.3854	1.3854	-	2.1
2008	121.51	121.89	123.06	123.21	122.42	86.39	1.4171	1.4171	-	2.1
2009	109.69	109.69	109.78	109.88	109.76	76.53	1.4342	1.4342	-	2.2
2010	109.95	110.49	111.05	111.15	110.66	76.53	1.4459	1.4459	-	2.2
2011	112.40	113.12	113.84	114.08	113.36	76.60	1.4799	1.4799	-	2.2
2012	114.60	115.04	115.81	116.07	115.38	76.60	1.5063	1.5063	-	2.3
2013	106.11	106.26	106.78	107.20	106.59	70.64	1.5088	1.5088	-	2.3
2014	107.66	108.23	108.60	108.64	108.28	70.57	1.5344	1.5336	0.00	2.3
2015	109.10	109.67	110.03	110.29	109.77	70.57	1.5555	1.5556	(0.00)	2.3
2016	110.63	111.26	111.65	112.21	111.44	70.57	1.5791	1.5792	(0.00)	2.4
2017	112.75	113.03	113.61	114.27	113.42	70.57	1.6072	1.6072	-	2.4
2018	109.37	110.27	110.68	111.22	110.38	67.33	1.6396	1.6396	-	2.5
2019	111.47	112.19	112.66	113.04	112.34	67.33	1.6686	1.6687	(0.00)	2.5
2020	113.42	112.82	113.84	114.37	113.63	67.33	1.6877	1.6878	(0.00)	2.5
2021	115.65	117.41	119.12	121.19	118.37	67.33	1.7582			2.6

	Year	Q1	Q2	Q3	Q4	AVG.	1992	Recalc'd	Actual	Delta	PTC Rate
Zero Inflation	2022	123.545	*123.545*	*123.545*	*123.545*	*123.545*	67.33	1.8351			***2.8***
		0	*0%*	*0%*	*0%*	1.9%					
Inflation Req'd to 2.9 cents	2022	123.55	126.41	129.35	132.35	127.92	67.33	1.9000			***2.9***
			2.32%	*2.32%*	*2.32%*	*9.2%*					

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UE 400

In the Matter of	)
	)
PacifiCorp, dba Pacific Power,	)
	)
2023 Transition Adjustment Mechanism.	)
	)

EXHIBIT AWEC/104

PGE PRODUCTION TAX CREDIT FORECAST FOR 2023

Taylor La Prairie

From:	Robin Kapela
Sent:	Thursday, March 10, 2022 5:22 PM
To:	Taylor La Prairie
Subject:	RE: Updated PTC Forecasted Rates

Hi Taylor,

The hydro PTC rate is just the 1/2 the wind rate.

Robin Kapela Tax Analyst | 503-464-7761

From: Taylor La Prairie <taylor.laprairie@pgn.com>
Sent: Thursday, March 10, 2022 5:16 PM
To: Robin Kapela <Robin.Kapela@pgn.com>
Subject: RE: Updated PTC Forecasted Rates

Hi Robin,

Thank you for sending this to me. Can you provide updates to the hydro PTC rate as well, or clarification on how to derive the hydro PTC from this table? As I understand it, right now, the rate per kWh is $.013.

Best,
Taylor

Taylor La Prairie Power Cost Forecasting Analyst

From: Robin Kapela <Robin.Kapela@pgn.com>
Sent: Tuesday, March 8, 2022 3:28 PM
To: Jon Bildner <Jon.Bildner@pgn.com>; Taylor La Prairie <taylor.laprairie@pgn.com>; Marco Espinoza <Marco.Espinoza@pgn.com>
Subject: Updated PTC Forecasted Rates

Hello,

Here is the list of updated PTC forecasted rates.

Year	$ Rate per KWh
2023	0.028
2024	0.028
2025	0.029
2026	0.030
2027	0.030
2028	0.031

2029	0.032
2030	0.032
2031	0.033
2032	0.034
2033	0.035
2034	0.035
2035	0.036
2036	0.037
2037	0.038
2038	0.039
2039	0.039
2040	0.040
2041	0.041
2042	0.042
2043	0.043
2044	0.044
2045	0.045
2046	0.046
2047	0.047

PGE

Robin Kapela
Tax Analyst | 503-464-7761
portlandgeneral.com | Follow us on social @PortlandGeneral
An Oregon kind of energy.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

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	)

EXHIBIT AWEC/105

UTAH SCHEDULE 34

ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

ROCKY MOUNTAIN POWER

ELECTRIC SERVICE SCHEDULE NO. 34

STATE OF UTAH

Renewable Energy Purchases for Qualified Customers – 5,000 kW and Over

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PROVISION: This Schedule governs contract guidelines for the Company to acquire renewable energy on behalf of qualified Customers, pursuant to Utah Code Annotated **§** 54-17-806.

AVAILABILITY: At any point on the Company's interconnected system where there are facilities of adequate capacity.

APPLICATION: To Customers in all territory served by the Company in the state of Utah whose total aggregated electric load is at least 5,000 kW, based on annual peak load. A Customer may aggregate multiple metered delivery points under a single corporate entity to satisfy the 5,000 kW threshold, based on annual peak load at each delivery point. Annual peak load will be based on the Customer's highest Demand reading during the prior 12-month period or its reasonably projected Demand including planned load expansions in the subsequent 12-month period. For new Customers, annual peak load will be based on the Customer's Contract Demand, to be reached within a ramp-up period of 36-months or such other period approved by the Commission.

MONTHLY BILL: As approved by the Commission, Customers taking service under this schedule shall be subject to all charges and rates specified in the Customer contract pursuant to Conditions of Service section 1.c., including monthly cost-based administrative fees for metering and billing.

Standard Administrative Fee (if not otherwise included in Customer contract):
$110 per generation source, and
$150 for the first Delivery Point, and
$50 per any additional Delivery Points

(continued)

ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

ELECTRIC SERVICE SCHEDULE NO. 34 - Continued

CONDITIONS OF SERVICE:

1. A contract is required for each Customer taking service under this Schedule. The Customer contract is subject to approval by the Commission.
   a. The Customer contract will provide delivery of electricity to the Customer by the Company from one or more renewable energy resources. See Conditions of Service paragraph 4, below, for eligible renewable energy resources criteria.
   b. The maximum amount of renewable energy to be acquired on behalf of a Customer hereunder shall be based upon the reasonably projected annual amount of energy to be consumed by the Customer, based on known and sound forecast methods typically used by the Company for large customers. Any energy output that exceeds the Customer's usage on an annual basis will be compensated at the Company's then-current Schedule 37 avoided costs for the relevant resource type.
   c. The Customer contract will include rates calculated in compliance with Utah Code Annotated § 54-17-806. Under the Customer contract the Customer shall pay:
      i. the Customer's normal tariff rate as specified in the applicable Electric Service Schedule (which may include a special contract as described in Electric Service Regulation 3(3)),
      ii. cost-based administrative fees, and:
      iii. either,
         1. an incremental charge equal to the difference between the cost to the Company to supply renewable generation to the Customer and the Company's avoided costs as defined in Utah Code Annotated § 54-2-1(1), or
         2. an amount based on a different method set forth in the Customer contract and approved by the Commission.
   d. The Customer contract will contain service termination provisions obligating the Customer to continue to pay all of the costs of the renewable energy resource(s) acquired by the Company on the Customer's behalf in the event the Customer contract is terminated early and a cost obligation related to the renewable energy resource(s) continues beyond the termination. At the discretion of the Company, a Customer with multiple delivery points shall have the option to transfer the renewable energy contract obligation of one delivery point to a new or existing delivery point within the Company's service territory without termination fees.
   e. The Customer shall be required to provide adequate credit assurances.
   f. The Customer contract shall specify the consequences if a new Customer fails by the end of the ramp up period described in the Application section, if applicable, to meet the 5,000 kW eligibility requirement for participation under this Schedule.
   g. The Customer contract shall address the extent to which rate adjustments identified in Electric Service Schedule 80, including but not limited to the Energy Balancing Account in Electric Service Schedule 94, will apply to the Customer.

(continued)

ELECTRIC SERVICE SCHEDULE NO. 34 - Continued

2. Approval by the Commission of an amount calculated using either method identified in Condition of Service 1.c.iii. under this schedule shall be based on a finding that the amount calculated is just and reasonable and in the public interest. Evaluation of the public interest shall include consideration of use of system facilities and contributions to system fixed costs, and any other issues the Commission determines to be relevant.

3. At the request of a Customer, the Company may agree to enter into a new contract with another customer to accommodate a transfer of the Customer's rights and obligations with respect to a renewable energy resource to another Customer, subject to Commission approval of the new contract.

4. The following provisions set out the criteria for renewable energy resources eligible under this schedule:
   a. A generation facility that derives its energy from a renewable energy source as defined in Utah Code Annotated § 54-17-601. The renewable resource may be owned by the Company, the Customer or any other person or entity(ies), provided that the Company will enter into a contract under reasonable terms and conditions to buy output from renewable energy resources owned by others.
   b. Renewable energy credits (RECs) associated with renewable energy delivered under this Schedule will be deposited into an account maintained by or on behalf of the Customer, and will be retired. If specified in the contract, unbundled RECs can be acquired in the marketplace by the Company on behalf of the Customer at the Customer's expense to allow the Customer to meet its renewable energy goals during time periods when a Customer's electrical usage is ramping up to full intended levels or the Customer is in the process of attempting to secure renewable resources.
   c. Renewable resources eligible for contract under this Schedule must not already be included in the Company's rates.
   d. The Company will take physical delivery of output from the renewable energy facility and will provide electric service to the Customer.

5. The Company will require a nonrefundable application fee of $5,000.00 from each Customer requesting service under this Schedule, as a partial offset to the Company's costs related to the preparation of a contract for review by the Commission, which fee shall not be refunded whether a contract is ultimately executed. For purposes of application of this fee, one application fee will be assessed on a Customer aggregating multiple points of delivery.

(continued)

ELECTRIC SERVICE SCHEDULE NO. 34.4 – Continued

ELECTRIC SERVICE REGULATIONS: Service under this Schedule will be in accordance with the terms of the Electric Service Agreement between the Customer and the Company. The Electric Service Regulations of the Company on file with and approved by the Public Service Commission of Utah, including future applicable amendments, will be considered as forming a part of, and be incorporated in said Agreement.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UE 400

In the Matter of	)
	)
PacifiCorp, dba Pacific Power,	)
	)
2023 Transition Adjustment Mechanism.	)
	)

EXHIBIT AWEC/106

MARKET CAP ANALYSIS

Historical Market Cap Analysis

	Actaual NPC Sales Adj. For Book-Outs						Average	PacifiCorp Proposed Mkt Caps			No Mkt Caps		
	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2016-2021	AURORA	Δ to Avg.	%	AURORA	Δ to Avg.	%
MWh Excl. Bookouts	6,018,797	6,651,663	7,765,501	4,947,298	4,885,911	4,652,718	6,053,834	2,642,174	(3,411,661)	-56%	5,125,482	(928,352)	-15%
Bookout MWh*	6,130,887	6,967,136	8,968,222	8,044,824	4,947,283	1,779,035	7,011,670	3,174,759	(3,836,911)	-55%	3,099,143	(3,912,527)	-56%
MWh Incl. Bookouts	12,149,684	13,618,799	16,733,723	12,992,122	9,833,194	6,431,753	13,065,505	5,816,933	(7,248,572)	-55%	8,224,625	(4,840,880)	-37%
								55%					
Rev $ Excl. Bookouts	148,084,741	189,651,228	224,869,978	168,712,218	173,806,881	175,995,889	181,025,009	158,918,464	(22,106,545)	-12%	289,993,254	108,968,245	60%
Bookout Rev. $*	141,563,258	176,562,582	239,685,688	215,933,990	135,193,456	62,562,372	181,787,795	177,194,015	(4,593,780)	-3%	201,183,969	19,396,175	11%
Rev. $ Incl. Bookouts	289,647,999	366,213,810	464,555,666	384,646,208	309,000,337	238,558,261	362,812,804	336,112,479	(26,700,325)	-7%	491,177,224	128,364,420	35%

BEFORE THE

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	)

EXHIBIT AWEC/107

PSCO CONTRACT EVALUATION

PSCo Contract Versus Market at Time of Execution

Sales Volumes

	aMW		Hours			Dollars		
Month	HLH	LLH	HLH	LLH		HLH	LLH	Total
1/1/2023	55	26	416	328		22,880	8,528	31,408
2/1/2023	55	26	384	288		21,120	7,488	28,608
3/1/2023	54	26	432	312		23,328	8,112	31,440
4/1/2023	40	32	400	320		16,000	10,240	26,240
5/1/2023	40	32	416	328		16,640	10,496	27,136
6/1/2023	60	32	416	304		24,960	9,728	34,688
7/1/2023	60	37	400	344		24,000	12,728	36,728
8/1/2023	60	37	432	312		25,920	11,544	37,464
9/1/2023	60	37	384	336		23,040	12,432	35,472
10/1/2023	50	26	432	312		21,600	8,112	29,712
11/1/2023	50	26	400	320		20,000	8,320	28,320
12/1/2023	50	26	400	344		20,000	8,944	28,944
					Total	259,488	116,672	376,160

Revenue At Contract Price

	$/MWh		Dollars		
Month	HLH	LLH	HLH	LLH	Total
1/1/2023	30.00	20.50	686,400	174,824	861,224
2/1/2023	30.00	20.50	633,600	153,504	787,104
3/1/2023	30.00	20.50	699,840	166,296	866,136
4/1/2023	23.75	20.50	380,000	209,920	589,920
5/1/2023	23.75	20.50	395,200	215,168	610,368
6/1/2023	23.75	20.50	592,800	199,424	792,224
7/1/2023	75.00	21.00	1,800,000	267,288	2,067,288
8/1/2023	75.00	21.00	1,944,000	242,424	2,186,424
9/1/2023	75.00	21.00	1,728,000	261,072	1,989,072
10/1/2023	23.75	20.50	513,000	166,296	679,296
11/1/2023	23.75	20.50	475,000	170,560	645,560
12/1/2023	23.75	20.50	475,000	183,352	658,352
			10,322,840	2,410,128	12,732,968

Revenue at 08.11.2022 OFPC

	$/MWh		Dollars		
Month	HLH	LLH	HLH	LLH	Total
1/1/2023	48.10	48.00	1,100,546	409,344	1,509,890
2/1/2023	46.04	47.00	972,407	351,936	1,324,343
3/1/2023	41.85	42.00	976,328	340,704	1,317,032
4/1/2023	29.38	29.00	470,138	296,960	767,098
5/1/2023	31.15	31.00	518,403	325,376	843,779
6/1/2023	63.72	51.75	1,590,555	503,460	2,094,014
7/1/2023	183.87	65.71	4,412,885	836,347	5,249,231
8/1/2023	183.83	67.72	4,764,866	781,787	5,546,653
9/1/2023	149.71	63.16	3,449,337	785,144	4,234,481
10/1/2023	50.75	49.91	1,096,131	404,880	1,501,011
11/1/2023	39.55	39.62	790,970	329,638	1,120,608
12/1/2023	43.09	42.90	861,782	383,698	1,245,480
			21,004,348	5,749,273	26,753,621

Delta	**14,020,653**
SG	25.75%
Oregon Allocated	**3,610,891**