BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 390

In the Matter of	)
	)
PACIFICORP, dba PACIFIC POWER,	)
	)
2022 Transition Adjustment Mechanism.	)
	)
	)

REDACTED OPENING TESTIMONY

OF THE

OREGON CITIZENS' UTILITY BOARD

June 9, 2021

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OF OREGON

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	)	TESTIMONY OF THE OREGON
2022 Transition Adjustment Mechanism.	)	CITIZENS' UTILITY BOARD
	)	

I. INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is Bob Jenks. I am the Executive Director of the Oregon Citizens' Utility Board (CUB). My business address is 610 SW Broadway, Ste. 400 Portland, Oregon 97205.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in exhibit CUB/101.

Q. What is the purpose of your testimony?

A. This testimony responds to issues raised by PacifiCorp (PAC or the Company) in its 2022 Transition Adjustment Mechanism (TAM), filed with the Oregon Public Utility Commission (Commission) on April 1, 2021. CUB reviewed PacifiCorp's filing and has a number of concerns. CUB also reviewed the Issues List issued by Administrative Law Judge Rowe on May 21, 2021.

Q. How is your testimony organized?

A. First, CUB will address our concerns with Issue 3, the Company' proposal to change the methodology used to determine its market capacity limits that reduce the forecast of short-term firm and balancing sales. Second, CUB has concerns related to Issue 1, how the Company models coal plant operations and the impact of minimum take coal contracts on those operations. Finally, CUB will address concerns with the schedule for next year's 2023 TAM.

II. MARKET CAPACITY LIMITS

Q. How does PacifiCorp's Generation and Regulation Initiative Decision Tools (GRID) model operate in terms of market prices?

A. The Company uses GRID to forecast its net power costs (NPC) in the TAM each year. GRID is a model that simulates the dispatch of PacifiCorp's resources. It is designed to interact with the wholesale power market, allowing it to forecast market purchases and market sales at various hubs. It does not model the regional market. This means that if it includes a market price that is above the dispatch cost of PacifiCorp's marginal unit(s), it will dispatch that unit(s) into the market. It will dispatch as much power as PacifiCorp has that is not needed to serve load into the market even if this volume exceeds the demand of the market. This happens because GRID does not forecast market demand – it dispatches resources based on what it is told is the market price.

Q. What is the purpose of a market capacity limit or market cap?

A. Market caps are a way to constrain GRID and prevent it from over-forecasting sales. Markets are extremely dynamic. Markets are constantly adjusting to supply and demand, transmission constraints, current and expected weather, plant availability, fuel prices and other factors. The use of market caps in the GRID model was fully litigated in the 2013 TAM. There, much of the issue was about the inability of GRID to forecast market liquidity and allowing market caps to serve as a substitute for that liquidity.

Q. Does CUB believe that market caps are necessary?

A. CUB is not disputing that GRID is limited in terms of its ability to forecast a functioning wholesale market. However, next year, PacifiCorp will switch from GRID to the AURORA model to forecast NPC in the TAM. AURORA will have better capabilities, as it looks beyond dispatching the utility's system and includes prices at load points across the region as a whole. But for this year, we are left with GRID as our modeling tool and trying to get it to produce the most accurate forecast that is possible. In 2012, the Commission found that, based on the way GRID is constructed, some level of market cap was necessary.[1]

Q. What is PacifiCorp's current market cap methodology?

A. The Company's current methodology uses the maximum monthly market sales capacity from the last four years to set monthly market caps, which limit the volume of short-term firm and balancing sales that GRID will allow.[2]

Q. What changes is PacifiCorp proposing to this methodology?

A. Rather than setting the cap based on the maximum level of monthly sales for the last four years, the Company is proposing using the average of each month's short-term firm, balancing and spot sales to set the cap. CUB is concerned that this methodology will under-forecast market sales.

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[1] OPUC Order No. 12-409.
[2] UE 390 – PAC/100/Webb/11, lines 7-9.

Q. Why do you believe that PacifiCorp's new methodology will under-forecast market sales?

A. CUB has two concerns with PacifiCorp's proposed approach. First, the mathematics of using averages to set caps is problematic. Second, the new methodology is backwards looking and fails to recognize that PacifiCorp's market sales are trending upward. This upward trend reflects the fact that PacifiCorp's available resources are changing; that the marginal resource being dispatched into the market is often a lower cost resource than it previously was; and that all things being equal the Company has positioned itself to win a greater share of the market than it had previously. CUB recommends the Commission reject PacifiCorp's proposal. However, if the Commission agrees with PAC that a new methodology is necessary, that methodology should be designed to forecast the level of market sales expected on a going forward basis.

Q. Please explain your concern about the mathematics of PacifiCorp's new approach.

A. PacifiCorp explains its new approach in simple terms:

> For example, for the month of January, PacifiCorp would now take the average of the past four Januarys for each trading hub to develop the market cap. A lower market cap reduces the market depth at each hub, which reduces market sales modeled in GRID, and results in fewer wholesale sales which increases NPC.[3]

Using an average to set a cap is problematic. An average recognizes that there are numbers above the average and that there are numbers below the average. When the average is used as a cap, it eliminates the numbers that are above the average,

[3] UE 390 – PAC/100/Webb/12, lines 4-7.

but allows numbers that are below the cap. If you had three children, ages 2, 6 and 13, their average age is 7. But if you said that instead of identifying the real ages, you will no longer count any years above the average, then you would claim your children are 2, 6 and 7 with an average age of 5. Mathematically, this simply does not make sense.

Q. Please explain your concerns about PacifiCorp's proposal's failure to recognize that PacifiCorp's market sales are trending upward.

A. At issue here are short-term firm and balancing sales. In recent PCAMs, PacifiCorp has identified that the current methodology has overestimated the actual short-term firm and balancing sales. But the actual sales for the last 4 years, in GWh, show a trend upward.[4]

2017	2018	2019	2020	2022 TAM forecast
7371	6441	10624	9114	[redacted]

The average of 2017-2020 is 8388 GWh, but PacifiCorp is not proposing a forecast equal to the average of the last four years. Instead, it is asking that the monthly average of the last four years be used to set monthly caps. This results in a forecast that is [begin confidential] [redacted] [end confidential] But this also ignores the trend. The average of the 2019 and 2020 is 9869 GWh, while the average of the 2017 and 2018 is 6906 GWh. This

[4] UE 344 – PAC/100/Wilding/10; UE 361 – PAC 100/Wilding/11; UE 379 – PAC/100/Webb/11; UE 392 – PAC/100/Painter/12; UE 309 – Webb Confidential Workpapers ORTAM22 TAM CONF

upward trend makes sense due to the dramatic changes to PacifiCorp resource base over the last four years.

Q. Describe the change in PacifiCorp resources and how it explains this trend.

A. There has been a dramatic shift in the Company's resource base. In Confidential Exhibit 102, CUB compares the initial TAM forecast in 2018 to this initial forecast for 2022. The four-year average PacifiCorp uses is 2017, 2018, 2019, and 2020. CUB chose 2018 for comparison, recognizing that the changes we discuss below occurred after 50% of PacifiCorp average was fully baked into their number set. Using the initial forecast from 2018 was done to compare a weather-normalized forecast to a weather-normalized forecast. The Comparison shows dramatic changes to the Company's resources. Coal generation has [begin confidential] [redacted] [end confidential] But the biggest change in in renewables. Company-owned wind production has [begin confidential] [redacted] [end confidential] Wind and solar under long term contracts have also [begin confidential] [redacted][5] [end confidential]

Solar and wind do not have a fuel cost, and therefore have an incremental cost near zero and will dispatch to their maximum level based on weather.[6] They are variable resources that produce based on the amount of sun and wind. If the wind

[5] CUB Exhibit 102 CONF.

[6] Solar and wind that is under contract will show up in the TAM with a unit cost ($XX/MWh), but this represents PacifiCorp's contract terms. The owner of the asset recognizes the zero marginal cost and dispatches them to PacifiCorp based on their maximum production levels.

is blowing at night when a utility has a minimum amount of load, it will sell the power into the market as long as it can find a buyer. Coal is different. Coal has fuel costs. In 2018, PacifiCorp had Naughton 3 and Cholla burning coal. Their production costs were [begin confidential [redacted][7] [end confidential] The 2018 annual average price for System Balancing Sales, the largest component of the market sales category at issue here, was [begin confidential] [redacted][8] [end confidential] PacifiCorp has replaced coal plants that were often not economic as market resources with renewables which are always economic in the market. This should lead to an increase in market sales.

Of course, resources are not dispatched to market based on a yearly average price. PacifiCorp's power plants are used to serve load first, and may be dispatched into the market if generation exceeds load. Market sales will depend what is the next resource in the Company's resource stack after serving load and how that marginal resource compares to the market price. The addition of significant renewables should lead to a lower dispatch cost resource being the marginal unit. All things being equal, if a market participant enters a market with a lower cost product, that participant should win a greater volume of the market. In addition, going into a market with a lower cost resource will increase the margin on that sale. Therefore, market sales should increase and net income from those sales should increase at an even greater level.

[7] UE 361 TAM Workpapers, OR2018 NPC Study CONF.
[8] UE 361 TAM Workpapers, OR2018 NPC Study CONF.

Q. Does PacifiCorp dispute that an increase in renewables increases market sales?

A. No. But their proposed methodology does not account for the changing resource base. PacifiCorp looked at the impact the new wind projected added in this TAM (TB Flats, Cedar Springs I, II and III, Ekola Flats and Pryor Mountain) and concluded that they would increase balancing sales by 233 GWh.[9] It is important to remember that this increase happened with the GRID model's market caps based on average sales, so GRID's ability to sale the added renewables into the market was constrained by the historic average volume of sales. It is also important to recognize that this included the newly added wind projects but did not include the repowering of PAC's wind fleet that occurred between 2018 and 2020.

Q. Does CUB have an alternative proposal?

A. Yes. Adding renewables to PacifiCorp's fleet should increase market sales. PacifiCorp agrees that it does and there is a clear trend of increasing market sales. It is important to recognize this trend in any methodology that forecasts market sales.

The Company is proposing to change away from the current methodology and bears the burden of proof to demonstrate it is a reasonable alternative. This burden has not been met. Since the methodology that Company proposes does not adjust for its changing resource base, the Commission should reject this new

[9] UE 390 – PAC/100/Webb/28.

methodology. The problem being addressed is a problem that is associated with the GRID model. Next year, the Company will stop using the GRID model to forecast power costs and replace it with AURORA, which has greater capabilities when it comes to modeling the market prices associated with trading hubs in the Western region.

However, CUB recognizes that there has been an over-projection of market sales. What is needed is a methodology that recognizes the changing nature of PacifiCorp's generation system while reducing the caps from their current level. CUB believes that such a mechanism is possible. CUB Exhibit 103 shows that actual short-term firm and balancing sales have been increasing by 7.88% per year. CUB accepts the Company's market cap average methodology as representative of 2017 to 2020, but then escalates it by 16.38% to allow account for the upward trend in these sales[10]. CUB then applies this 16.38% increase to the monthly market caps.

Making this adjustment in GRID would allow market sales to reflect the changing nature of PacifiCorp's generation. However, the effect of this on the TAM will depend on how much it increases sales, the price of those sales, and the underlying cost of the resource that is being used to produce the power that is being sold.

[10] CUB Exhibit 103, see CUB workpaper ORTAM22 Dir_Market Capacity Dec 20 CONF CUB for applying this to monthly caps at market hubs

III. COAL PLANT DISPATCH

Q. What are CUB's concerns about coal plant dispatch?

A. In recent years, stakeholders have expressed concerns about whether PacifiCorp's Coal Supply Agreements (CSAs)—which require PacifiCorp to purchase a significant amount of coal—are inappropriately driving the dispatch of coal plants beyond what is economic. These contracts have take-or-pay requirements which require the Company to pay for a certain level of coal regardless of whether the Company needs the coal, or liquidated damages which require the Company to pay a penalty for purchasing below a certain volume of coal. For the purposes of this testimony, I am referring to both as "minimum take" provisions. This issue, combined with PacifiCorp's historic practice of placing a "must-run" requirement on coal plants to prevent GRID from eliminating them as resources when they are not economic, raises questions about both the modeling and the operation of its coal fleet. CUB believes that both issues are still a concern.

1. Minimum Take Provisions

Q. What evidence is there that coal contract minimum take provisions are driving coal dispatch?

A. Several of PacifiCorp's coal plants are operating at levels just above the minimum take levels:[11]

[11] CUB Exhibit 104 – Sierra Club 1.6c

[Begin Confidential]

[redacted]

[End Confidential]

From this chart we can see that Colstrip, Hayden, Hunter and Huntington are all have contract minimum take provisions that are [begin confidential] [redacted] [end confidential] But the expected generation is not allowed to go below the minimums. In actual operations, the Company dispatches the coal unit as if it has no fuel costs up to that contract minimum:

> The take-or-pay provisions in PacifiCorp's coal supply agreements [CSAs] require the payment for the coal even if it is not delivered or used for generation, therefore the fuel portions of the marginal cost of generation in that price tier is zero. The Company does not use the average price as a dispatch price in short-term forecasts because the cost of coal in a take-or-pay volume tier is not avoidable.
>
> For example, suppose a CSA had a provision with a minimum take-or-pay volume of 1 million tons. The incremental price for volumes between zero and 1 million tons would be zero because the take-or-pay volumes are treated as a previously incurred cost[12].

This means that when actual fuel costs are considered in the dispatch decision, there is very little additional generation at [begin confidential] [redacted] [end confidential]

[12] CUB Exhibit 105, Sierra Club 1.5

2. New CSAs

Q. Does CUB have concerns about the new coal supply agreements that were added in this proceeding?

A. Yes. The Company has entered into five new CSAs: two related to the Dave Johnston plant, two related to the Hunter plant and one related to the Craig plant. CUB notes the significant contrast between the Dave Johnston and Hunter CSAs.

Q. What is the contrast between the Dave Johnston and Hunter CSAs?

A. Dave Johnston consists of four older coal units. The oldest came online in 1959. [begin confidential] [redacted][13] [end confidential] They are scheduled to close in 2027 as an alternative to expensive retrofits under Regional Haze regulations. The two new contracts are priced favorably as Dave Johnston is in the Powder River Basin and has a number of competitive options. They are take-or-pay contract that require the Company [begin confidential] [redacted] [end confidential] of its expected annual fuel supply. PacifiCorp is confident that it can procure the remaining supply at reasonable cost due to the plant's location.

The contract prices are favorable when compared to other CSAs and the take-or-pay risk is reduced by the [begin confidential] [redacted] [end confidential] Because it has [begin confidential] [redacted] [end confidential] of any of PacifiCorp's coal plant, it is likely to operate at a high capacity factor and unlikely to be economically cycled. The primary take-or-pay

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[13] 361 TAM Workpapers, OR2018 NPC Study CONF.

risk would be associated with significant outages of the plant and that is managed [begin confidential] [redacted] [end confidential

At the Hunter plant, PacifiCorp replaced a long-term (20 year) supply agreement with [begin confidential] [redacted] [end confidential] But unlike Dave Johnston, the Hunter CSA [begin confidential] [redacted] [end confidential This increases the likelihood that the plant may run uneconomically. CUB is concerned about the amount of coal that is subject to the minimum take provision. [begin confidential] [redacted] [end confidential] it is the same volume that was in the previous agreement. PacifiCorp's view of its requirements at the Hunter plant are unchanged from the year 2000. This, in spite of the fact that it has reduced it coal generation by 32% from 2018 to 2020.[14] The contract minimum take provision accounts for [begin confidential] [redacted] [end confidential] of the forecast production at the plant.[15] One of the contracts [begin confidential] [redacted] [end confidential] so the Company's operation of the plant is not limited by the minimum take provision. CUB is concerned that the minimum take provisions does not allow enough flexibility. A plant outage, or the growing supply of renewables could lead to the contract minimums placing additional costs on customers.

Q. Does CUB recommend adjustments for the Hunter coal supply contracts?

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[14] CUB Exhibit 102.
[15] CUB Exhibit 105, Sierra Club 1.5.

A. No. CUB has concerns regarding these Hunter contracts and their minimum take provisions but we are not recommending any adjustments to the 2022 TAM for the contracts. Much of the risk associated with the take-or-pay contracts will fall into the current PCAM deadband, which is functioning as intended. We will, however, monitor the performance of these contracts in future power cost case and may recommend adjustments in a future proceeding.

3. Huntington Coal Contract.

Q. In last year's TAM order, the Commission raised concerns about the Huntington CSA. Has CUB reviewed the Huntington CSA?

A. Yes. The Huntington CSA is a long-term agreement that grew out of the Deer Creek Mine settlement. When this agreement first came before the Commission, CUB joined the Company in arguing that it was a prudent contract. That was done based on the Company's claim that the Company could get out of the contract if environmental regulations made the contract uneconomic.

In that docket, PacifiCorp stated that:

> "[t]he Huntington CSA provides the Company with broad termination rights if new environmental laws or regulations, or a settlement agreement, adversely affect the Company's ability to consume coal at the Huntington power plant."[16]

In CUB's response testimony, CUB argued that much of the value of this depended on whether it applied only to environmental laws and regulations that directly affected the plant's operations, or whether it applied to environmental laws and regulations that affected the plant's economics and therefore indirectly affect the plant's operations. PacifiCorp responded to this by stating that it could

[16] UM 1712 – PacifiCorp's Application for Approval at 9-10.

terminate the coal supply agreement if environmental laws or regulations affected the economics of the plant:[17]

> **Q. Parties are also concerned that the long-term CSA creates an incentive for the Company to continue to burn coal at Huntington when it would otherwise be uneconomic to do so and therefore limits the Company's future options. Please respond.**
>
> **A**. Because the Company can exercise its termination rights if it becomes uneconomic to burn coal at Huntington, there is no incentive to continue burning coal when it is uneconomic to do so and the Company's options are not limited.

It was after this assurance by the Company that CUB urged the Commission to find this agreement to be prudent. Since 2015, when the Commission considered this, there have been a great deal of changes to environmental laws and regulations. Oregon passed SB 1547 that phases out coal plants and requires 50% renewables. Washington and California have passed 100% clean electricity laws. The Company has responded by investing billions in new renewables.

The issue is not whether the contract was prudent in 2015, but whether new environmental laws and regulations has led to uneconomic coal dispatch under the contract.

Q. Does CUB have a recommendation with regards to the Huntington CSA?

A. CUB believes that the Company should conduct an analysis to determine whether the contract is leading to uneconomic dispatch of the plant, whether that is related to new environmental laws and regulations and whether it is in customers' interests to invoke the contract termination provisions.

[17] UM 1712 – PAC/500/Crane/7.

4. Must Run/Coal Cycling

Q. What are your concerns abouts the Company's use of must run requirements for coal plants that prevent those plants from economic cycling?

A. Economic cycling is where a plant is closed for a period of time due to economic reasons. The Company has historically modeled coal plants with must run requirements that limit the ability of GRID to economic cycle these plants. Because of an agreement reached in last year's TAM, the Company did not include must run requirements, but they included other restrictions on coal plant dispatch. The Company included a confidential study of allowing coal plants to economically cycle and included it with this filing. CUB believes that this study raises concerns particularly about the operations of [begin confidential] [redacted] [end confidential]

Q. Did the Company's Confidential analysis of this issue impact your thinking?

A. Confidential Exhibit 107 is a study of economic cycling of coal plants that the Company conducted. The Company points to this having [begin confidential] [redacted][18] [end confidential]

But the study also showed that [begin confidential] [redacted][9] [end confidential] This is

[18] UE 390 – Exhibit PAC/107/Webb/3 CONF.
[19] UE 390 – CONF Exhibit PAC/107/Webb/5.

consistent with the IRP which found that the preferred portfolio included the retirement of Jim Bridger 1 at the end of 2023.[20] The original coal study conducted as part of the IRP concluded that there was a benefit in closing Jim Bridger Unit 1 in 2022.[21]

PAC Exhibit 107 raises real doubts about the [begin confidential] [redacted] [end confidential] The Company states that in actual operations it will typically cycle a coal unit to its minimum when needed but will not entirely shut it down[22] and cites reliability concerns due to the time that it takes to bring a unit back online. CUB has trouble understanding how temporarily cycling down a Bridger unit would cause reliability problem up until December 2023 at which time the unit can be completely shut down.

Q. Does CUB have a recommendation related to cycling coal plants?

A. Yes. CUB has two recommendations. The coal study that was conducted as part of the IRP found there was a customer benefit to closing Jim Bridger Unit 1 in 2022.[23] [begin confidential] [redacted] [end confidential] First, CUB would like to see the Company conduct a GRID study that closes Bridger 1[begin confidential] [redacted] [end confidential] Second, CUB believes that PacifiCorp should generally allow

[20] OPUC Order No. 20-186.
[21] LC 70 – Volume II, Appendix R
[22] UE 390 – PAC100/Webb/13.
[23] LC 70 --- Volume II, Appedix R

GRID to economically cycle Bridger 1 in its forecasts and that its operators should also increase the economic cycling of Jim Bridger 1 in actual operations.

IV. 2023 TAM

Q. Please summarize CUB's requested change.

A. Due to the shift in modeling software that will occur in next year's proceeding, CUB believes stakeholders will need additional time to evaluate the Company's filing to ensure the TAM forecast is reasonable. For the 2023 TAM, CUB recommends that the Company file make its initial filing for the TAM on January 15, 2022. Under the TAM Guidelines, TAM filings made in a general rate case year must be filed no later than March 1. If the TAM is filed on a stand-alone basis, as it is this year, the initial filing must occur no later than April 1. While this process has worked in prior TAM proceedings, in the next TAM proceeding, PAC is moving from using the GRID model to AURORA to forecast its Net Power Costs. CUB requests a change to the initial filing date to accommodate a necessarily intensive stakeholder review of the nodal pricing model and PacifiCorp's implementation of AUOROA.

Q. What program is currently used to model net variable power costs for PacifiCorp in the TAM?

A. PacifiCorp has used the GRID model for several decades to determine NPC for regulatory filings. The GRID model deterministically models the Company's net variable power cost subject to the Company's transmission topology, resources, and access to markets.

Q. Does the Company plan on using a different modeling software to model net variable power costs?

A. Yes. The Company is planning on moving toward using the AURORA Model, which is developed by a third-party company Energy Exemplar.

Q. Are there any major differences between the GRID model and the AURORA model?

A. While the GRID and AURORA models use similar inputs to determine net variable power costs, AURORA has more parameters to model resources and facilitates a larger transmission topology. Unlike the internally created GRID model, the AURORA model uses publicly sourced, and continually updated tested datasets. It is a more complicated modeling software. The combination of switching to new software that is also more complicated makes it necessary to provide stakeholders with adequate time to review the filing.

Q. Has CUB been preparing for the move from GRID to AURORA internally?

A. Yes. CUB has attended training for its regulatory staff to gain exposure to using the AURORA model. CUB understands that PAC is working to move towards AURORA for power cost modeling and is looking forward to gaining hands-on experience with the AURORA model.

Q. Does CUB have any concerns about the current date for TAM?

A. Yes. If PacifiCorp files the TAM on April 1, Intervenors and Commission Staff would only have a two-month window to review a major modeling change for net variable power cost. This time frame may have worked when reviewing regular annual updates. However, it has taken several years for the PAC to implement this modeling change. CUB expects this proceeding to require more time to review due to the amount of modeling changes.

V. CONCLUSION

Q. Can you summarize CUB's recommendations for this proceeding?

A. Yes. CUB makes the following recommendations:

Market Cap Methodology. The Commission should reject PacifiCorp's proposed methodology for calculating market caps. As an alternative, the Commission should adopt CUB's recommended methodology which establishes new, lower market caps but recognizes that changes in PacifiCorp's resource base has created an upward trend in market sales.

Huntington CSA. The Company should conduct an analysis to determine whether the contract is leading to uneconomic dispatch of the plant, whether that is related to new environmental laws and regulations and whether it is in customers' interests to invoke the contract termination provisions.

Jim Bridger Unit 1. The Company should consider closing Jim Bridger Unit 1 [begin confidential] [redacted] [end confidential] and should allow Jim Bridger Unit 1 to be economically cycled in GRID and in actual operations.

2023 TAM. Due the change from GRID to AURORA, the Company should file next year's TAM on January 15, 2022.

Q. Does this conclude your testimony?

A. Yes.

UE 390– CERTIFICATE OF SERVICE

I hereby certify that, on this 9th day of June, 2021, I served the **Confidential Opening Comments of the Oregon Citizens' Utility Board** in docket UE 390 upon the Commission and each party designated to receive confidential information pursuant to Order 16-128 through a secure, encrypted attachment to an e-mail.

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TITLE: Executive Director

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EDUCATION: Bachelor of Science, Economics
Willamette University, Salem, OR

EXPERIENCE: Provided testimony or comments in a variety of OPUC dockets, including UE 88, UE 92, UM 903, UM 918, UE 102, UP 168, UT 125, UT 141, UE 115, UE 116, UE 137, UE 139, UE 161, UE 165, UE 167, UE 170, UE 172, UE 173, UE 207, UE 208, UE 210, UE 233, UE 246, UE 283, UG 152, UM 995, UM 1050, UM 1071, UM 1147, UM 1121, UM 1206, UM 1209, UM 1355, UM 1635, UM 1633, and UM 1654. Participated in the development of a variety of Least Cost Plans and PUC Settlement Conferences. Provided testimony to Oregon Legislative Committees on consumer issues relating to energy and telecommunications. Lobbied the Oregon Congressional delegation on behalf of CUB and the National Association of State Utility Consumer Advocates.

Between 1982 and 1991, worked for the Oregon State Public Interest Research Group, the Massachusetts Public Interest Research Group, and the Fund for Public Interest Research on a variety of public policy issues.

MEMBERSHIP: National Association of State Utility Consumer Advocates
Board of Directors, OSPIRG Citizen Lobby
Telecommunications Policy Committee, Consumer Federation of America
Electricity Policy Committee, Consumer Federation of America
Board of Directors (Public Interest Representative), NEEA

CUB Exhibit 102 is Confidential and has been served upon the Commission and each party designated to receive confidential information pursuant to Order 16-128.

		GWh	**Precent Change**
2017	1	7371	
2018	2	6441	-14%
2019	3	10624	39%
2020	4	9114	-17%
4 year average		8387.5	
change from 2017 to 2020		1743	23.65%
average change		581	7.88%
2021 forecast		9832.183	
2022 forecast		10606.96	
change from 2010 to 2022		1492.959	16.38%

CUB Exhibit 104 is Confidential and has been served upon the Commission and each party designated to receive confidential information pursuant to Order 16-128.

Sierra Club Data Request 1.5

With respect to the dispatch and costing tiers of the Company's coal units in NPC:

(a) Please explain the use of different dispatch or costing price tiers in GRID and what each represents.

(b) Please explain and provide a numeric example for how the dispatch and costing tiers are related to the total unit price of coal for a fixed price or take-or-pay fuel contract.

(c) Please explain and provide a numeric example for how the dispatch and costing tiers are related to the total unit price of coal for a fuel contract with liquidated damages (i.e., damages less than the total cost of fuel).

(d) Please explain and provide a numeric example for how the dispatch tier and costing tiers are related to the total unit price of coal for a fuel contract with no fixed terms or liquidated damages.

(e) For each of the company's coal units, please provide the calculations used to derive the dispatch and costing tier. Please provide all associated work papers used to calculate the two tiers.

Response to Sierra Club Data Request 1.5

(a) Please refer to the Company's response to Sierra Club Data Request 1.2, subpart (l).

(b) The take-or-pay provisions in PacifiCorp's coal supply agreements (CSA) require the payment for the coal even if it is not delivered or used for generation, therefore the fuel portion of the marginal cost of generation in that price tier is zero. The Company does not use the average price as a dispatch price in short-term forecasts because the cost of coal in a take-or-pay volume tier is not avoidable.

For example, suppose a CSA had a provision with a minimum take-or-pay volume of 1 million tons. The incremental price for volumes between zero and 1 million tons would be zero because the take-or-pay volumes are treated as a previously incurred cost. Suppose further that the CSA set a price for the first 1 million tons at $2 per million British thermal units ($/MMBtu), and any purchases above 1 million tons were $1/MMBtu. The incremental price above the take-or-pay volume of 1 million tons would be $1/MMBtu. Assuming that the Company purchased 2 million tons, the average or "costing tier" price in the Generation and Regulation Initiative Decision Tool (GRID) would be

$1.50/MMBtu, and the incremental or "dispatch tier" price would be $1/MMBtu.

(c) Liquidated damages provisions provide for a payment, less than the full price of coal, to be due if PacifiCorp fails to take the minimum contract volume. The Company accounts for liquidated damages in its dispatch analysis by recognizing that these costs will be incurred if the units are not dispatched at a level that consumes coal above the contractual minimums.

For example, suppose the same CSA example in the Company's response to subpart (b) above had a liquidated damages provision in conjunction with the minimum volume of 1 million tons. Therefore, instead of the Company having a full take-or-pay provision and being obligated to pay $2/MMBtu for any shortfall of volumes below 1 million tons, the liquidated damages provision called for a payment of $0.25/MMBtu for any shortfall. Therefore, the "dispatch tier" price would be $1.75/MMBtu for volumes between zero tons and 1 million tons. The "dispatch tier" for volumes over 1 million tons would be $1.00/MMBtu. If the Company purchased 2 million tons, the "costing tier" price would remain at $1.50/MMBtu.

(d) Leaving aside the complexities that accompany multiple tiers, in an instance where there is a single tier with no minimum take and no maximum, the costing tier and dispatch tier would be identical.

(e) The "dispatch tiers" used in GRID for purposes of the 2022 transition adjustment mechanism (TAM) are determined via an iterative process to arrive at a fuel consumption number that satisfies the minimum purchase obligations of contracts with such provisions. As such, there is no closed form calculation and no work papers to provide. Please refer to the confidential work papers supporting the direct testimony of Company Witness, Dana M. Ralston for details on the calculation of costing tier prices.