BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 375

In the Matter of	)
	)
PACIFICORP, dba PACIFIC POWER,	)
	)
2021 Transition Adjustment Mechanism.	)
	)

OPENING TESTIMONY

OF THE

OREGON CITIZENS' UTILITY BOARD

May 15, 2020

(Redacted Version)

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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. In my testimony, I recommend several adjustments in response to arguments made by PacifiCorp ("PAC" or "the Company") in the filing of its 2021 Transition Adjustment Mechanism ("TAM"). I also recommend a change to the TAM Guidelines, which is appropriate in a general rate case year.[1]

[1] *In re PacifiCorp, dba Pacific Power, 2009 Transition Adjustment Mechanism Schedule 200, Cost-Based Supply Service,* OPUC Docket No. UE 199, Order No. 09-274 at Appx. A, Page 9 (Jul. 16, 2019) ("Nothing in this agreement prevents any Party, including the Company, from advocating in a future general rate case or other proceeding other than a stand-alone TAM, that the TAM should be eliminated or revised.") (hereafter "TAM Guidelines").

Q. What is the purpose and goal of the TAM?

A. According to the Company, the purpose is to update net power costs ("NPC") for 2021 and to set transition credits for Oregon customers who choose direct access in the November open enrollment window. In the TAM, forecasts are used to adjust the Company's rates, which makes forecast accuracy significantly important.[2]

Q. Please summarize your testimony.

A. In my testimony, I recommend several adjustments:

1. In a change to the TAM Guidelines, I recommend wheeling revenues ("Transmission Revenues" or "OATT Revenues") which are currently forecast in the general rate case ("GRC") and updated annually through a deferral should be moved into the TAM. These revenues are more appropriately handled in the TAM. Transmission Revenues are variable, associated with the production and transmission of bulk power, parallel wheeling costs (which are included in the TAM), and are included in the Company's Utah annual power cost proceeding.
2. Legacy pension costs associated with the Deer Creek Mine should be removed from the TAM and moved into base rates, which will be determined in the GRC, OPUC Docket No. UE 374. These costs are fixed, not variable, have no relationship to 2020 net power costs, parallel the legacy pension costs associated with coal plant retirements (which are considered in the GRC), and should be recovered as by adding [redacted] to pension expense (FAS 87).
3. Jim Bridger coal production should be adjusted to remove the impact of the SCRs which have not been demonstrated to be prudent.
4. The penalties associated with reduced coal burning due to the conversion of Naughton 3 to gas should be shared. PacifiCorp has only recently begun to address the economic risk of burning coal, in spite of ample warnings and direction to address this risk. Costs that were incurred because of PacifiCorp's delayed approach should not be fully allocated to customers.
5. PacifiCorp's proposal to model Energy Imbalance Market ("EIM") benefits should not be accepted.

[2] *In re PacifiCorp, dba Pacific Power's 2017 Transition Adjustment Mechanism,* OPUC Docket No. UE 307, Order No. 16-482 at 2 (Dec. 20, 2016).

II. WHEELING REVENUES

Q. What are PacifiCorp's wheeling revenues?

A. PacifiCorp is a wholly-owned subsidiary of MidAmerican Energy Holdings Company. It provides delivery of electric power and energy to approximately 2 million retail electric customers in six western states. The retail customer rates are regulated by the six state's public utility commissions. PacifiCorp owns or has interest in approximately 16,500 miles of transmission lines. The Company uses this transmission system to deliver power to retail customers. PacifiCorp also buys and sells access to transmission. When PacifiCorp needs to deliver power to its system, PacifiCorp purchases transmission service from other transmission operators. The cost of this is called wheeling cost. PacifiCorp is a major provider of wholesale transmission service in the West; the revenue generated from providing wholesale transmission service is called wheeling revenue.

Q. What is the ratemaking treatment for Wheeling costs and revenues?

A. Wheeling costs vary from year-to-year and are forecast and recovered through the annual TAM mechanism.[3] Wheeling revenues also vary from year-to-year, though they trend upward. Currently, wheeling revenues are forecast at a base level in the GRC and, since 2013, deferred accounting has been used to track revenues greater than amount embedded in base rates.

Q. What change is CUB proposing to make to the TAM Guidelines?

A. CUB is proposing to change the TAM Guidelines to include amounts booked to FERC Account 565 – Transmission of Electricity by Others in the determination of

[3] UE 375 – PAC/100/Webb/8, lines 15-16.

NPC. This TAM is being filed during a general rate case year, and is not a stand-alone TAM proceeding. Therefore, parties can propose revisions to the guidelines.[4]

Q. Why is CUB proposing this change?

A. These revenues fit well into the TAM. Wheeling revenues are variable, associated with the production and transmission of bulk power, parallel wheeling costs which are already included in the TAM, and are updated annually in Utah's annual power cost proceeding. The current methodology of establishing a baseline in the GRC and then using deferred accounting to track increases is not ideal. CUB believes these variable revenues should be forecast alongside variable power costs in the TAM.

Q. Why are wheeling revenues variable?

A. There are two reasons.

First, transmission usage is a function of how a utility dispatches its system to meet load. Utilities and other load serving entities (LSEs) must use transmission lines to move bulk power to distribution systems so it can be delivered to customers. The use of transmission is a function of energy demand, the performance of generation assets, and wholesale power prices. These factors are influenced by season, temperature, time of day, fuel prices, and economic conditions. Transmission costs and revenues are like NPC in that they are caused by the dispatch of power by LSEs to meet load.

[4] *Supra*, note 1.

The second reason is the rate that PacifiCorp charges for use of its transmission system changes annually. Transmission rates are regulated by FERC. FERC has approved formula rates for PacifiCorp:

> The Company's transmission formula rate is updated annually with the annual transmission revenue requirement (ATRR) that represents the annual total cost of providing firm transmission service over the test year. The ATRR calculation incorporates all transmission system investments by the Company, a return on rate base, income taxes, expenses, and certain revenue credits, among other specific elements and adjustments.[5]

The forecast of transmission revenues in the GRC test year is based on the formula rates that PacifiCorp expects in 2021.[6] But the transmission revenue requirement will be reset and rates in 2022 will be different, which will require a new deferral to track the difference between the wheeling revenues forecast in the rate case and the wheeling revenues expected from new rates. This is inefficient and poor ratemaking. Since PacifiCorp's transmission rates are set annually, it makes sense to also adjust wheeling revenues and costs annually in the TAM.

Q. How are wheeling costs treated?

A. Wheeling costs are included in the TAM. The current forecast projects that wheeling costs will increase by $8 million in 2021 due primarily to the California ISO introducing nodal pricing.[7] However, wheeling costs will be updated later in the TAM for new transmission contracts, changes in the terms of existing contracts, changes in third-party transmission rates, and contracts whose prices are linked to market indexes and inflation rates.[8] The transmission rates that PacifiCorp pays to

[5] UE 374 – PAC/1000/Vail/12.
[6] Because transmission rates are set on a June 1—May 31 basis, the 2021 forecast is actually a combination of the June, 2020—May 2021 transmission rate and the June 2021 – May 2022 transmission rate.
[7] UE 375 – PAC/100 Webb/16.

[8] UE 375 – PAC/106/Webb/2.

other transmission owners change annually. Including wheeling costs in the TAM not only allows reforecasting them annually, but allows PacifiCorp to update the TAM as new rates are set.

Q. What is CUB's proposal for wheeling revenues?

A. CUB believes that they should be treated in the same manner as wheeling costs. Wheeling revenues should be forecast annually in the TAM and, to the degree that PacifiCorp transmission rates change during the TAM proceeding, these revenue forecasts should be updated. It would be unfair to set them in a GRC and leave them untouched while customers pay the annual revenue requirement increases associated with other transmission owners who sell to PacifiCorp.

Q. Wheeling revenues are currently updated annually through deferred accounting, why not continue this approach?

A. If the Commission leaves transmission revenues in the GRC, then deferred accounting is an alternative approach. This will require a party to file a deferral application on January 1, 2022 and have it renewed every year until there is a new GRC. But deferred accounting is not the preferred manner of ratemaking. As the Commission notes, "deferrals should be used sparingly" and the Commission "will consider whether there are other more appropriate regulatory tools to address recovery of the identified costs or revenues."[9] Rather than relying on it, it makes more sense to forecast transmission revenues in the TAM. Further, there are several other problems with using deferred accounting.

[9] *In re Public Utility Commission of Oregon, Investigation into the Scope of the Commission's Authority to Defer Capital Costs*, OPUC Docket No. UM 1909, Order No. 20-147 at 13 (Apr. 30, 2020).

First, deferred accounting creates a timing mismatch between costs and revenues. In 2022, customers would be paying rates that reflect 2022 wheeling costs at 2022 FERC-approved wheeling rates, but the transmission credits would still reflect 2021 wheeling revenues at 2021 FERC-approved wheeling rates. The difference would be deferred, but those deferrals would flow back to customers at some later date.

Second, deferring transmission revenues can also lead to large deferral balances. Having pots of money that the Company owes to customers can be useful in solving problems, but it is not transparent ratemaking. In 2016, the transmission revenue deferral was $18.5 million and the Commission decided to amortize it over 4 years to customers, but to first subtract the MSP equalization adjustment.[10] The equalization adjustment was an agreement between the MSP parties to add a surcharge to state's revenue requirement to recognize that the MSP agreement in place at the time did not allow PacifiCorp to fully recover its costs. Oregon's annual surcharge was $2.6 million.[11] PacifiCorp customers paid $2.6 million per year to PacifiCorp as part of this agreed upon MSP equalization adjustment, but it showed up on bills as reduced wheeling revenue. Earlier this year, the wheeling revenue deferral balance was used to offset the remaining rate base associated with investment that was being removed from PacifiCorp's wind plants as part of its wind repowering.[12] While CUB supported these actions, we recognize that these actions do not represent ideal, transparent ratemaking.

[10] OPUC Order No 16-491.
[11] OPUC Order No 16-491.
[12] UM 374 – PAC/1300/McCoy/33.

Q. How does Utah treat wheeling revenues for ratemaking purposes?

A. Utah includes wheeling revenues as an offset to NPC in its annual power cost tracker. The Utah Commission:

> determined that while not modeled through the Generation and Regulation Initiative Decision Tool (GRID), wheeling revenues have a relationship with NPC in that they form an offset to wheeling expenses.[13]

CUB finds the logic of the Utah Commission compelling on this issue.

Q. Are there other reasons to make this change?

A. Yes. As the Western United States continues to explore new regional approaches, the treatment of wheeling costs and revenues could change. For example, a new extended day-ahead market (EDAM) might include wheeling costs and revenues. Placing both wheeling costs and wheeling revenues in the TAM would create more regulatory flexibility and enhance Oregon's ability to accommodate new regional markets outside a general rate case.

III. LEGACY DEER CREEK PENSION COSTS

Q. What are legacy Deer Creek Pension costs?

A. In 2015, the Commission found that closing PAC's Deer Creek mine produced a "substantial net benefit" to customers.[14] Much of this benefit derived from changes in future pension liability. Closing the mine allowed PacifiCorp to withdraw from the 1974 Pension Trust associated with the mine. The Pension Trust was a multi-employee pension plan that was very under-funded. Keeping the mine open and staying in the trust would result in incurring substantial future liability.

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[13] Utah PSC, Order in DOCKET NO. 09-035-15, page 8.

[14] OPUC Order No 15-161, page 5.

Withdrawing from the pension trust required PacifiCorp to incur a penalty, which could be paid with a lump sum payment or a [redacted] [redacted] payment "in perpetuity."[15] The Commission found that withdrawing from the trust and agreeing to pay this [redacted] penalty would provide "significant net benefits to customers."[16] CUB and PacifiCorp recommended, and the Commission approved placing that [redacted] payment in the TAM, where it has been since. For the 2021 TAM, PacifiCorp allocated [redacted] of this to its Huntington coal plant and [redacted] to Hunter.[17] CUB no longer believes that the TAM is the appropriate recovery vehicle for this cost and proposes to move it base rates determined in the GRC as a [redacted] increase to pension expense.

Q. Why is CUB proposing this Change?

A. This cost is fixed, not variable, and has no relationship to the cost of fueling either Huntington or Hunter. It is not part of NPC.[18] Instead, it should be included in pension expense in the same manner as legacy pension costs associated with PacifiCorp employees who once worked at Huntington or Hunter but are retired. Further, such a move would clarify how these costs should be treated under SB 1547.

Q. Please explain why these are not appropriate for NPC?

A. The pension cost is a fixed cost that PacifiCorp pays regardless of whether it burns coal at Huntington, Hunter or any other facility. This cost has nothing to do with

[15] OPUC Order No. 15-161, page 5.
[16] OPUC Order No. 15-161, page 9.
[17] UM 375 – PAC/300/Ralston/16.

[18] UE 375 – PAC/100/Webb/8 ("NPC are the sum of fuel expenses, wholesale power purchases, and wheeling expenses, less wholesale sales revenue.").

the current fueling costs at Huntington and Hunter. If those plants closed, PAC would continue to occur this cost. If PacifiCorp was powered by 100% renewable energy, PacifiCorp would continue to incur this cost. If PacifiCorp divested itself of generation and pursued all its power through market purchases and PPAs, the Company would incur this cost. It is a legacy cost associated with coal mining pensions from a mine that no longer is operating. It has nothing to do with current NPC.

Q. Please explain how this treatment compares to legacy pension costs of coal plant workers?

A. Employees who worked at the coal plants also have legacy pension costs. These costs are recovered through general rate cases and identified as Pension Expense, not coal production expense. CUB believes that for ratemaking purposes there is no reason to treat these two costs differently.[19]

Q. How does this change help clarify how these costs are treated under SB 1547?

A. SB 1547 directs PGE and PacifiCorp to eliminate the costs and benefits of coal fire resources by 2030. Continuing to label these legacy pension costs as part of the cost of fueling Huntington and Hunter identifies these costs as current costs of coal fire resources. This identification will lead to these costs being unrecoverable after January 1, 2030. Removing these costs from net power costs and placing them in pension expense will help make clear that these are not costs associated with coal resources used to provide electricity to retail customers – by 2030 there will not be coal resources providing electricity to Oregon retail customers of PacifiCorp. I was

[19] From a bookkeeping/accounting basis, there may be reasons to treat these differently but for ratemaking purposes Deer Creek pensions costs should act as a $3 million annual adder to pension expense (FAS 87).

CUB's representative in the negotiations that led to SB 1547 and lobbied in support of the bill. The bill was not intended to create barriers to PacifiCorp's recovery of legacy pension expenses associated with coal mining, or operating coal expenses. Its intent was to eliminate coal from the fuel mix of Oregon utilities by 2030.

IV. JIM BRIDGER SCRs

Q. How is PacifiCorp proposing to treat the Bridger SCRs in this TAM?

A. While the capital costs associated with an environmental upgrade like an SCR are considered in a general rate case, SCRs affect the performance of coal units which increase NPC. PacifiCorp installed a SCR on Jim Bridger Unit 3 in November 2015 and a SCR on Jim Bridger Unit 4 in November of 2016. In this docket, PacifiCorp is proposing to increase NPC to reflect the effect that the SCRs have on Bridger's operation. CUB opposes this proposed increase to NPC because the installation of SCRs has not been found to be prudent.

Q. Has this issue been considered in a TAM since the SCRs were installed? If so, please explain.

A. Yes. In the 2017 TAM, PacifiCorp proposed such a treatment. CUB objected because the SCRs had not been found to be prudent. PacifiCorp removed those costs to "avoid litigation" over the issue.[20] In the 2018 TAM, PacifiCorp again included these costs in its TAM filing. CUB objected, requesting an adjustment of

[20] UE 307 – PAC/400/Dickman/14.

$168,000 to remove the effect of the SCR.[21] In response to CUB's testimony, PacifiCorp again removed the costs.[22]

Q. Has PacifiCorp requested a prudence determination on the SCRs?

A. Yes. In the current GRC, PacifiCorp is requesting a prudence determination. However, the issue will be contested and will be unresolved when a final order in this docket is published. These were installed in 2015 and 2016. Since then the Company has not asked for a prudence determination on this capital investment. As CUB has argued in previous TAM, it is inappropriate to increase rates because of an investment that has not been found to be prudent.

Q. What effect would removing the impact of the SCRs have on TAM rates?

A. The effect will be relatively small. PacifiCorp's step log did not separate out the effects of the change in the Bridger minimum operating requirements from changes at other coal plants. In 2018, the cost was $168,000. To identify the cost, PacifiCorp should conduct a GRID run that removes the operating constraints associated with SCRs.

V. NAUGHTON COAL PENALTIES

Q. What are the Naughton coal penalties?

A. With Naughton 3 discontinuing burning coal and converting to natural gas, PacifiCorp is no longer able to burn the minimum amount of coal required under its fuel contract. Under the terms of PacifiCorp's Naughton fuel contract, PAC is

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[21] UE 323 – CUB/100/Jenks/3.

[22] UE 323 – CUB/200/Jenks/1-2.

required to pay a penalty in order to lower volume of coal deliveries. These penalties began last year. PacifiCorp includes [redacted] in penalties in its NPC for 2021.[23]

Q. Did CUB request a similar adjustment last year?

A. No. A review of last year's TAM suggests no party contested the issue. CUB has limited resources and does not investigate every potential issue. However, just because we do not object to an element of rates does not necessarily mean that we approve that element.

Just as important, CUB is hesitant to impose costs on PacifiCorp shareholders for actions that reduce the economic risk associated with coal such as discontinuing burning coal at Naughton 3. It has taken years to get PacifiCorp to seriously begin phasing out coal plants. Now that the Company is acting in a manner that aligns with stakeholder and ratepayer interests, there is discomfort about disallowing costs that are part of this transition. But now that this transition has begun, CUB has been forced to wade into this issue, both here and in the GRC. Over the last decade, PacifiCorp has incurred millions of dollars in unnecessary costs due to it bullish attitude towards coal, even as the Commission repeatedly warned the Company to more fully consider the risks associated with coal generation. Requiring the Company absorb costs when it takes actions to reduce coal burning seems like we are proposing to punish it for doing the right thing. It may seem like CUB is saying that adding an SCR is imprudent and not putting on an SCR and ending coal

[23] UE 375 – PAC/300 Ralston/12

burning is imprudent. However, CUB cannot ignore the fact that as other utilities were moving away from coal, PacifiCorp was retrofitting plants, extending their useful lives and signing long term coal contracts. PacifiCorp was incurring millions of dollars in liability that it believes is the responsibility of customers. CUB believes the Company acted prudently when it decided to end coal burning at Naughton 3. But CUB has serious doubts concerning the prudency of the 2010 long term coal supply contract that assumed an SCR would be installed at Naughton 3 and that all three Naughton units would continue running through the length of the contract. Fundamental ratemaking principles require that ratepayers should be held harmless when a Company acts imprudently.

Q. What is CUB's recommendation regarding these penalties?

A. While CUB believes that a strong case can be made to fully disallow these penalties, CUB is recommending that that penalties be shared equally between customers and the Company. This sharing is primarily because the imprudent action in this case came early in the Company's decade of inaction – it relates to a coal contract that was signed in 2010.

Q. What was imprudent about the contract?

A. The contract for coal deliveries at Naughton was a 11.5-year contract signed in 2010[24] that assumed that the three Naughton Units would continue business-as-usual operations, including retrofitting Naughton 3 with a SCR as part of its Clean Air Act regional haze obligations. By this time, Portland General Electric had proposed eliminating its proposed regional haze retrofit of the Boardman coal plant

[24] UE 375 – PacifiCorp Presentation to Oregon Commissioners, May 12, 2020. Page 6 (note: CUB is only referencing non-confidential information from this presentation).

and instead planned to close the plant in 2020.[25] Boardman had a 2015 regional haze compliance deadline. Naughton 3 had a December 31, 2014 compliance obligation.[26] PacifiCorp signed this coal supply contract knowing it had a regional haze obligation and with the knowledge that PGE's recent analysis demonstrated that under some circumstances it is more cost effective to phase out a coal plant than it is to retrofit it. In addition, the Company moved forward on this contract and this assumed retrofit of Naughton 3 in spite of warnings from the Commission.

Q. Please describe these warnings.

A. There were three Commission orders that the Company should have taken as a warning:

- Order 06-029. The Commission refused to acknowledge IRP action items relating to 600 MW of new coal generation in Utah. No parties to the IRP supported acknowledgment.[27]
- Order 08-232. The Commission refused to acknowledge IRP action items relating to two new coal investments: a 550 MW coal plant in Wyoming expected to be online in 2014 and a 340 MW coal plant in Utah expected to be online in 2012[28]:

> For the next planning cycle, consider the impact of forced early retirements of existing coal plants, or retrofits necessary to reduce their CO_2 emissions, under stringent carbon regulation scenarios[29].

[25] PGE To Close Boardman Plant by 2020, OPB, January 15, 2010 *available at* https://www.opb.org/news/article/pge-close-boardman-plant-2020/.
[26] CUB Exhibit 102, (Utah PSC Docket No 13-035-184 – PAC Exhibit TT0),
[27] OPUC Order No 06-029 ("None of the Parties, including Staff, recommends that the Commission acknowledge acquisition of a coal-fired resource in the summer of 2011.").
[28] OPUC Order No 08-232.
[29]OPUC Order No 08-232.

- Order 08-327. The Commission rejected a stipulation between Commission Staff and PacifiCorp revising depreciation rates and extending the life of coal plants. No party asked the Commission to reject the stipulation, but the Commission did so. The Commission's Order sent a clear warning to the Company:

> Pacific Power assumes that coal-fired generating plants will continue to be an economic source of power "well into the foreseeable future" and will stay in service as long as the plants are operational. Pacific Power also assumes that any increased capital expenditures resulting from environmental regulations will be recoverable in rates because the expenditures will be "for the benefit of customers.[30]

> and

> In other words, continued operation of a coal-fired generating plant could become uneconomic, leading to early retirement of the facility. Pacific Power ignores this possibility by assuming both that coal-fired generating plants will remain economic and that all capital expenditures associated with these plants will be recoverable in rates.[31]

In 2010, PacifiCorp needed a new contract for fuel supply at Naughton. It knew Unit 3 was facing a regional haze requirement. It knew that Oregon stakeholders were not supportive of new investments in coal plants. It knew that the Oregon Commission was directing it to consider the possibility of "forced early retirement of coal plants." PAC also knew that the Oregon Commission had admonished it for ignoring the possibility that a coal unit could become uneconomic and retire early. PacifiCorp assumed that Naughton 3 would remain economic. It assumed that the SCR investment on Naughton 3 would be made. It signed a coal supply contract based on its rosy assumptions about the future of coal.

Q. When did PacifiCorp reverse course on investing in the SCR?

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[30] OPUC Order No. 08-327.
[31] OPUC Order No. 08-327.

A. In September 16, 2011, the Company filed for an order granting a certificate of public convenience and necessity (CPCN).[32] This included a cost effectiveness analysis of the investment. This was the final step of the regulatory process before the SCR could be installed. Some of the parties to the case criticized the Company's analysis as outdated and the Company agree to update it in Rebuttal. On April 9, 2012, the Company updated its System Optimizer analysis and found that the investment was no longer cost effective when compared to closing the plant in 2014 and converting the plant to natural gas in 2015.[33] This results of the analysis were a surprise to the Company as it was moving forward with the plans to install the SCR. Four months earlier on December 8, 2011, PacifiCorp signed a contract to install the SCR.[34] CUB heard about this around this time and was also surprised. In CUB's view, PacifiCorp analysis was attempting to validate the SCR installation, not examine whether there was the least cost alternative.

Q. Please Explain.

A. PacifiCorp analyzed the difference in cost between installing an SCR in 2014 and closing the plant in 2014 and converting it to gas in 2015. CUB believed that this was unlikely to be the least cost alternative. One of the factors involved in a Regional Haze analysis is the life of the plant. PGE had already shown that a Regional Haze upgrade could be avoided by shortening the life of a plant, making the capital investment unnecessary. So, while an SCR was required by the end of 2014, the Company was not required to shut the plant as an alternative. It could

[32] CUB Exhibit 102. (Utah PSC document providing background on Naughton)
[33] CUB Exhibit 102.
[34] CUB Exhibit 102.

have proposed running the plant for a few more years and then converting it to gas or closing it down at that time. Because operating the plant was not uneconomic – it was the capital investment in the SCR that made it uneconomic, this should have been the least cost option. Ultimately this is what the Company did. In its 2013 IRP, the Company proposed running the plant until 2018 and then converting it to gas.[35] But in the CPCN process the Company did not analyze this least cost option to the SCR. This suggests that the Company was not looking for the least cost alternative to the SCR, but instead was attempting to justify the SCR.

Q. Please explain how this decision relates to the coal penalties at issue in this case.

A. The Commission was correct in its 2008 depreciation order. PacifiCorp was operating under the assumption that coal plants would not be found to be uneconomic, and that the cost of environmental upgrades could be passed through to customers. It signed a coal contract for the Naughton plants that assumed all of them would continue operating for more than a decade, even though it knew that Naughton 3 was subject to a costly Regional Haze upgrade that included an SCR. It was moving forward with installing an SCR when its final analysis showed that such an installation was not cost effective. The consequences have led to it not purchasing enough coal under its contract and having to pay penalties. CUB believes that if the Company had heeded the Commission warning, operated under an assumption that coal plants and coal plant upgrades might not remain cost effective then it likely would have signed a coal supply contract with lower

[35] OPUC Order No 14-252 pages 5-6.

minimum requirements on coal deliveries and lower penalties. Because the Company did not believe that shutting a plant was possible, it did not reasonably protect its customers from that risk. This is the reason that CUB believes sharing this penalty equally between customers and the Company is reasonable.

VI. EIM Benefits

Q. What is PacifiCorp's proposal for EIM benefits?

A. PacifiCorp is proposing a new methodology to forecast EIM transfer benefits. That methodology is based on a market fundamentals approach and uses four statistical models. PAC's forecast of transfer benefits based upon this methodology can be found in its confidential testimony.[36]

Q. Does CUB agree with this approach?

A. CUB generally finds the forecasted revenue to be reasonable based on historical benefits, but we have concerns about PacifiCorp's methodology. There is limited data set to show that the methodology is reasonably accurate. While PacifiCorp provided a backcast of 2019 to demonstrate the reasonableness of this methodology, CUB believes that a single year of data is not enough to demonstrate the reasonableness of such a complex methodology. Forecasting subhourly markets is not something that Oregon stakeholders have a lot of experience with and we should be cautious about endorsing a methodology with such little data to support it.

Q. Explain your concern about subhourly markets.

[36] UM 375 – PAC/200/Mitchell/4.

A. The EIM is a subhourly market where PacifiCorp participates on a 5- and 15-minute basis. PacifiCorp claims that it is important to use the same price forecasts as used in forecasting NPC[37], but PacifiCorp's NPC forecast does not utilize subhourly prices. Consider PacifiCorp's example:

> Consider a hypothetical, two-hour scenario in GRID where the market price is $25/MWh in the first hour and $40/MWh in the second hour with sales of 100 MWh in the bilateral market and incremental sales of 10 MWh in the EIM in each of the two hours. If GRID and the EIM transfer benefit forecast use the same market prices then the second hour would result in increased wholesale sales' revenue of $1,500 from the bilateral market and $150 from the EIM, reducing NPC by $1,650. However, if the EIM transfer benefit forecast does not use the same market prices as an input then forecast NPC for the EIM benefit could either be higher or lower, and it would be inconsistent with the expected drivers of the underlying market fundamentals and overall net power costs[38].

EIM does not operate in a world where the market price is $25/hour in the first hour and then increases by 65% to $40 in the second hour. It exists in a world of real-time activity with prices constantly changing. While the price might be $25 for part of one hour and $40 for part of another hour, they are not stagnant during the hour. If the price averages $25 for an hour, this does not mean that a generating unit with a marginal cost of $30 is not dispatch into EIM during part of that hour. While PacifiCorp's methodology forecasts an increase in EIM benefits of $150 in the example above, the actual benefits will be higher or lower than that based on what is happening within that hour.

Q. Does PacifiCorp's demonstrate a relationship between price and EIM transfer benefits?

[37]UE 375 – PAC/200/Mitchell/5.
[38]UE 375 – PAC/200/Mitchel/5.

A. Yes. PacifiCorp shows a relationship between prices and EIM transfer benefits, but that is based on day ahead prices.[39] Day-ahead market prices, even if they are hourly, are likely closer to subhourly prices than forecasts that are made more than one year in advance. It seems reasonable that there is a relationship between day-ahead prices and EIM transfer benefits. The relationship between day-ahead prices and EIM benefits tells us little about PacifiCorp's methodology because PacifiCorp's methodology does not use day ahead prices.

Q. What is CUB recommending with regards to PacifiCorp's EIM benefits?

A. CUB is willing to accept PacifiCorp's forecast of transfer benefits, because when compared to a three-year average of actual EIM benefits, it seems reasonable. CUB is not, however, willing to endorse the methodology that PacifiCorp used, and does not believe this methodology should be used in a manner that may create a precedent.

VII. CONCLUSION

Q. Please summarize your recommendations.

A. CUB has five recommendations:

1. Wheeling revenues which are currently forecast in the GRC and updated annually through a deferral should be moved into the TAM.

2. Legacy pension costs associated with the Deer Creek Mine should be removed from the TAM and moved into base rates determined in the GRC.

3. Bridger coal production should be adjusted to remove the impact of the SCRs which have not been demonstrated to be prudent.

[39] UE 375 – PAC/200/Mitchell/7 and 9.

4. The penalties associated with reduced coal burning due to the conversion of Naughton 3 to gas should be equally shared between the Company and its customers.

5. PacifiCorp's proposal methodology to forecast EIM benefits should not be approved.

Q. Does this conclude your testimony?

A. Yes.

WITNESS QUALIFICATION STATEMENT

NAME:	Bob Jenks
EMPLOYER:	Oregon Citizens' Utility Board of Oregon
TITLE:	Executive Director
ADDRESS:	610 SW Broadway, Suite 400 Portland, OR 97205
EDUCATION:	Bachelor of Science, Economics Willamette University, Salem, OR
EXPERIENCE:	Provided testimony or comments in a variety of OPUC dockets from the 1990s to 2020. , 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.

Naughton Unit 3 CPCN Docket Summary

As a result of the Company's 2011 Wyoming general rate case Docket No. 20000-384-ER-10, the Company is obligated to participate in a pre-project implementation certificate of public convenience and necessity ("CPCN") approval process and public review of certain planned major environmental projects in the state of Wyoming via a "Stipulation and Agreement" effective on June 6, 2011. The signatory parties to the Stipulation and Agreement included: Rocky Mountain Power; the Wyoming Office of Consumer Advocate; Wyoming Industrial Energy Consumers; QEP Field Services Company; Cimarex Energy Company; Interwest Energy Alliance; AARP Wyoming; City of Casper, Wyoming; Town of Mills, Wyoming; Town of Bar Nunn, Wyoming; Town of Midwest, Wyoming; Natrona County, Wyoming; Granite Peak Development, LLC; Kinder Morgan Interstate Gas Transmission LLC; Utility Workers Union of America, Local 127; AFL-CIO; and Power River Basin Resource Council.

On September 16, 2011, the Company applied to the Public Service Commission of Wyoming ("Commission") for an Order granting a CPCN to construct environmental compliance investments in a SCR and baghouse on Naughton Unit 3. On April 9, 2012, the Company filed rebuttal testimony and updated information in the proceeding, based on an updated analysis undertaken in response to changing market conditions and testimony filed by interveners, showing that the SCR and baghouse investments on Naughton Unit 3 are no longer cost-effective and that the interest of the Company and its customers would be best served by alternatively converting Naughton Unit 3 to a slow-start 100%

natural gas fueled peaking unit. The Company's updated analysis showed that the natural gas conversion was the risk-adjusted, least-cost compliance alternative when compared to the mandated SCR and baghouse (and other available options) using updated economic model input assumptions, updated market information and advancements in modeling methodology. The Wyoming Commission issued an Order granting the Company's motion to withdraw its CPCN application for SCR and baghouse on July 19, 2012.

In the Company's updated analysis, results from the System Optimizer ("SO") Model base case optimized simulation selected the natural gas conversion alternative, and in doing so, chose to avoid the SCR and baghouse project, and other environmental upgrades planned for Naughton Unit 3. The present value revenue requirement difference ("PVRR(d)") between the base case optimized simulation and the change case simulation showed that the natural gas conversion alternative was [redacted] favorable to the SCR and baghouse, and other environmental upgrades required for Naughton Unit 3 to continue operating as a coal-fueled facility. Additional sensitivity analysis around the base case analysis showed that the asset life and on-going operating cost assumptions ranges do not alter the updated base case results supporting natural gas conversion as the risk-adjusted, least-cost alternative to the SCR and baghouse investment at Naughton Unit 3. Key factors that changed in the Company's updated analysis included:

- Updates to the Company's base case natural gas price assumptions in response to lower observed forward market price and lower longer term natural gas price forecasts from third party experts.

- Updates and expansion of natural gas and carbon dioxide ("CO_2") sensitivity scenarios that are based upon a review of third party projections and that included varying combinations of natural gas and CO_2 price assumptions.
- Updates to the SO Model that incorporated a comprehensive assumption review process, aligning modeling assumptions with the Company's 2012 business plan and addressing issues by interveners.

SCR and Baghouse EPC Contract

In parallel with the CPCN proceedings described above, the Company competitively bid and negotiated an EPC contract associated with the SCR and baghouse during the period of December 23, 2010 (request for proposal release date) to December 8, 2011 (effective date of EPC contract). To comply with a December 31, 2014 compliance obligation, and given the uncertain outcome the CPCN proceeding at the time, the EPC contract was structured with a *limited* notice to proceed ("LNTP") concept and a *full* notice to proceed ("FNTP") authorization. The FNTP date was established as September 30, 2012. As a result of the Company's updated analysis in the CPCN proceeding, the EPC contract was suspended on February 27, 2012, during the LNTP period and ultimately terminated by the Company for convenience on December 31, 2012.

Naughton Unit 3 Deferred Accounting Docket

On May 3, 2012, the Company made application to the Public Service Commission of Utah under Docket No. 12-035-80, for an accounting order authorizing the Company to record a regulatory asset for the project development and LNTP phase costs incurred in the amount of approximately [redacted]

[redacted]. The costs were incurred in support of the anticipated project critical path schedule and included cost items associated with internal project development work; Owner's engineering consulting work; permitting applications and fees; design basis technical studies; Rocky Mountain Power interconnection costs; and early EPC contract detailed engineering, project execution planning and subcontracted site assessments. In its application, the Company specifically requested the Utah Commission to approve transfer of approximately [redacted] out of FERC Account 107 (Construction Work in Progress or "CWIP") and record a regulatory asset in FERC Account 182.3 (Other Regulatory Assets) that would be amortized over two years starting in the Company's next general rate case. The state of Utah's share of the regulatory asset would be established based on the system generation ("SG") allocation factor, resulting in an allocated amount of approximately $3.4 million. The Company did not request a final decision on rate recovery through its application in Docket No. 12-035-80 and proposed rate recovery of the Regulatory Asset in its next general rate case, and that amortization begin in that test period.

On August 7, 2012, the Company filed a settlement agreement and associated motions in the 2012 Utah general rate with the Utah Commission. The settlement agreement included a proposal to resolve the Naughton Unit 3 SCR and baghouse project development and LNTP phase cost deferral Docket No. 12-035-80. The Utah Commission issued an order on September 19, 2012, in a consolidated 2011 general rate case and two deferred accounting cases for decommissioning the Carbon plant and recovery of the Naughton Unit 3 SCR and baghouse project development and LNTP phase costs. In the settlement agreement, the parties agreed to defer and amortize the Naughton Unit 3 SCR and baghouse project development and LNTP phase costs by September 1, 2014, thereby providing full recovery to the Company prior to the effective date of new rates resulting from the 2014 general rate case.