Oregon Citizens' Utility Board

EST. 1984

610 SW Broadway, Suite 400
Portland, OR 97205

(503) 227-1984
www.oregoncub.org

July 27, 2020

Public Utility Commission of Oregon
201 High St SE, Suite 100
Salem, Oregon 97301

Re: UE 374 - In the Matter of PACIFICORP, dba PACIFIC POWER, Request for a General Rate Revision

The Oregon Citizens' Utility Board files herewith a correction to its originally submitted UE 374 Rebuttal and Cross-Answering Testimony on July 24, 2020. The testimony and exhibits were incorrectly labeled as CUB/300-310. The testimony and exhibits attached here are correctly labeled as CUB/400-410. CUB requests that this be amended and apologies for any inconvenience.

Please contact me if you have any questions with this filing.

Sincerely,

Michael P. Goetz, OSB #141465
General Counsel
Oregon Citizens' Utility Board
610 SW Broadway, Ste. 400
Portland, OR 97205
T. (503) 227-1984 x 16
F. (503) 224-2596
E. mike@oregoncub.org

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 374

In the Matter of	)
	)
PACIFICORP, dba PACIFIC POWER,	)
	)
Request for a General Rate Revision.	)
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REDACTED

REBUTTAL AND CROSS-ANSWERING TESTIMONY

OF THE

OREGON CITIZENS' UTILITY BOARD

July 24, 2020

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 374

In the Matter of PACIFICORP, dba PACIFIC POWER, Request for a General Rate Revision.	)))))))	REBUTTAL AND CROSS-ANSWERING TESTIMONY OF THE OREGON 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. What is the purpose of your Rebuttal and Cross-Answering Testimony?

A. I respond to issues raised in PacifiCorp's (PAC or the Company) Reply Testimony in response to CUB's Opening Testimony. This testimony also respond to some issues raised by Staff of the Oregon Public Utility Commission (Staff), the Alliance of Western Energy Consumers (AWEC), and Sierra Club.

Q. How is your Rebuttal Testimony organized?

A. My testimony is organized as follows:

A. COVID-19 Impacts and the Company's Request;
B. Cost of Capital;
C. Proposed Changes to the Power Cost Adjustment Mechanism (PCAM);
D. Wheeling Revenues; and

E. Jim Bridger Units 3 and 4 SCRs.

II. DISCUSSION

A. COVID-19 Impacts and the Company's Request

Q. The Company's Opening Case was developed before the COVID-19 emergency. CUB addressed the impacts of COVID-19 on the Company's customers in its Opening Testimony. In Reply Testimony, did the Company address how COVID-19 changes its case?

A. CUB's review of the Company's Reply Testimony found only one adjustment to the Company's case due to the COVID-19 emergency—the Company discussed what happens if it causes a construction delay for the new wind facilities that Company is constructing.[1] Beyond that, the Company spent a considerable amount of ink discussing how the effects of the virus on capital markets are not a reason to reject the Company's proposed capital structure and Return on Equity (ROE).[2] The Company dismissed CUB's concern that the economic effects of the virus on customers are a reason not eliminate the earnings test and deadbands associated with the current PCAM, which would shift risk to customers.[3] Finally, PAC was clear that it should get cost recovery for the effects of the virus on the Company's earnings.[4] In short, the Company's position is that everything it requested when this case was filed when unemployment was at record low levels is still appropriate, even with the largest numbers of customers unemployed since the Great Depression. The Company seeks to mitigate the risk COVID-19 may place

[1] UE 374 – PAC/2000/Wilding/9.
[2] UE 374 – PAC/2100/Kobliha/5; PAC/2200/Bulkley/3, 20, 22-23, 25-27, 29, 31-32, 50, 54, 81, 87-88, 114.
[3] UE 374 – PAC/3000/Graves/32-33.
[4] UE 374 – PAC/3000/Graves/33.

on its shareholders while simultaneously turning a cold shoulder to the impacts its rate request would have on its struggling customers.

Q. Do you agree with the Company that COVID-19 has little effect on the Company's case in this docket?

A. Absolutely not. The Governor of Oregon issued an emergency order more than four months ago and has extended it twice. PacifiCorp recognized this when it voluntarily issued a moratorium on disconnections. Hundreds of thousands of Oregonians have lost their jobs not due to poor performance, but their jobs have been sacrificed as a public health measure. Many of these customers are finding it difficult to pay for rent, utilities, food and medicine. If the Company gets its way, these customers will pay an additional $12 million per year to raise the Company's ROE from 9.8% to 10.2%. CUB is incredulous that the Company finds it appropriate to raise its rates so it can increase returns to its shareholders under these economic circumstances. I will provide further discussion of ROE later in my testimony, but the Company's attempt to increase profits while its customers are experiencing severe economic hardship shows a complete lack of empathy.

Q. What approach should the Company take to the COVID-19 crisis?

A. CUB challenges PacifiCorp to begin recognizing the hardship that many of its customers are facing and review its case to determine which requests should be put on hold or simply eliminated under these circumstances. Cutting costs and delaying new programs is a reasonable response to the crisis faced by customers. Many businesses and households that are customers of PacifiCorp are being financially harmed and are looking for places to reduce costs. State and local governments are seeing tax revenues decline and are looking for ways to cut programs and personnel. Non-profits are seeking alternative income sources in response to decreased donations or grants revenue and are cutting back on services. Meanwhile, PacifiCorp seems to think it has virus immunity because of its status as a monopoly utility.

However, if the utility will not eliminate unnecessary costs, then the regulator must. This is a time when customers need the protection of the Oregon Public Utility Commission (Commission). The Washington Utilities and Transportation Commission recently limited customer rate increases in Puget Sound Energy's general rate case in light of the uncertain economic environment caused by COVID-19.[5] Now is the time for the Commission to carefully examine similar customer protection measures.

B. Cost of Capital

Q. Did CUB sponsor Opening Testimony on cost of capital?

A. No. However, CUB has reviewed the Company's testimony, the testimony of Staff and AWEC, and the Company's subsequent response. CUB would like to respond to these parties' testimony as it relates to ROE.

Q. You already stated that the Company's proposal to increase its ROE is inappropriate because of the pandemic. Would it be reasonable if there was not a pandemic?

[5] CUB Exhibit 401 – Moody's issuer comment on PSE GRC.

A. No. While it is irresponsible to propose raising shareholder returns during the pandemic, I also want to highlight that the ROE PAC is asking for is out-of-line with other utilities, including Oregon utilities whose ROEs were set before the global pandemic. ROE is set at levels that reflect underlying financial conditions and represent the returns to shareholders that is necessary to attract capital. PacifiCorp's proposal is not consistent with the returns of other Oregon utilities and it is not consistent with returns in other states.

Q. How does it compare with other Oregon regulated utilities?

A. PacifiCorp has higher authorized returns than nearly all other regulated utilities in the state. ROE is determined in general rate cases based on financial conditions at the time of the rate case. On the following page is a chart that shows the authorized and requested ROEs of all utilities that have had at least two Oregon general rate cases in the last decade.[6]

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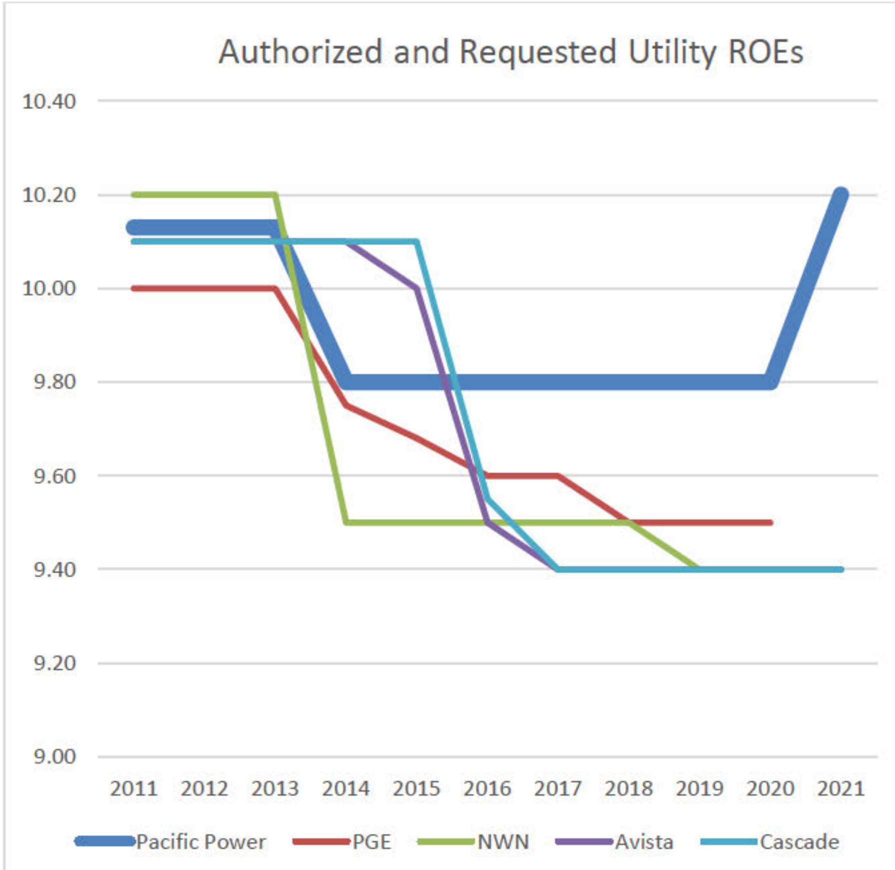
[6] This includes all regulated utilities except Idaho Power. Idaho Power's last rate case was in 2011 and its ROE was set at 9.90%. It has not been reviewed since that time, so it is not reflective of current market conditions.

CUB Figure 1



This chart shows that ROEs have been trending downward for the last decade. PacifiCorp's current ROE of 9.8% is greater than any other Oregon utility that has had a recent rate case. Avista, Cascade and NW Natural all have ROEs set at 9.4%, while Portland General Electric's is 9.5%. As the chart demonstrates, if PacifiCorp's request is approved in this case, it will have a significantly higher ROE than any peer utility in the state. Even staying at its currently authorized 9.8% would give it the highest by a significant margin. If PacifiCorp had filed an Oregon general rate case in the last five years, the Company would likely have a lower ROE today.

It is also worth noting that PacifiCorp is one of four utilities with a current general rate case seeking to raise Oregon rates in 2020. However, PacifiCorp is the only one that is proposing an increase in its ROE after the COVID-19 crisis. The other utilities have lower ROEs than PacifiCorp, which reflects Commission decisions in more recent rate cases. Even with these lower ROEs, other Oregon utilities are not asking the Commission to raise their ROE. This is demonstrated in the following table.

CUB Table 1:
Utilities with Oregon Rate Cases

	Current ROE	Proposed ROE
PacifiCorp	9.80%	10.20%
NW Natural	9.40%	9.40%[7]
Avista	9.40%	9.40%[8]
Cascade	9.40%	9.40%[9]

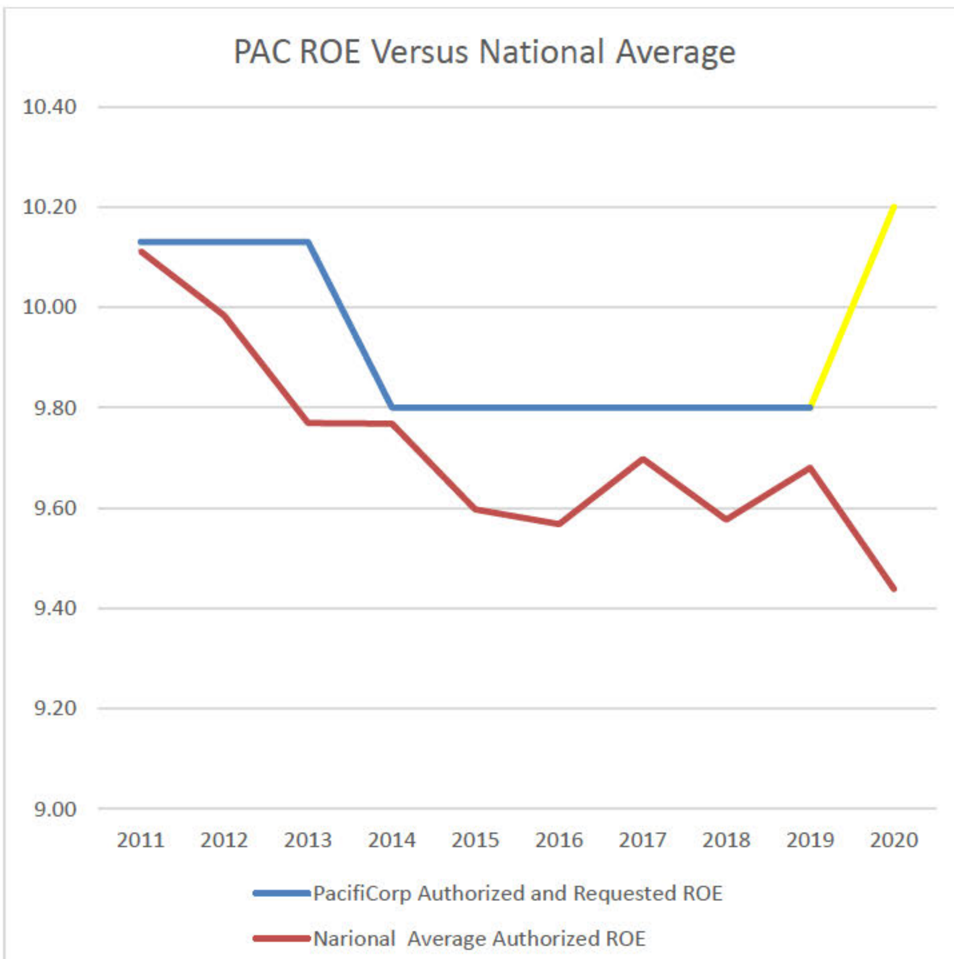
Q. You state that PacifiCorp's ROE request is not consistent with utilities in other states. What evidence do you have to support this?

A. Surprisingly, this information was provided in the testimony of PacifiCorp's own witness. CUB Exhibit 402 contains the numbers that are included in a table from PacifiCorp's testimony.[10] From this we can see that the ROE the Company is seeking, 10.2%, is greater than any of the 27 ROE decisions by Commissions anywhere in the country this year.[11] In addition, the average ROE authorized by

[7] UG 388 – Stipulating Parties/100.
[8] UG 389 – Joint Testimony/100.
[9] UG 390 – Cascade Natural Gas/Kivisto/8/Lines 5-6.
[10] CUB Exhibit 402, data from PacifiCorp/2200/Bulkley/11.
[11] UE 374 – PacifiCorp/2200/Bulkley/11.

Commissions in the US has not been above 10.0% since 2012.[12] Finally, the table and underlying data shows that ROEs have been falling since PacifiCorp's last Oregon rate case in 2013. At that time, the average ROE decision was 9.77 nationally, and was 9.78 in Oregon. There has been a general trend down since then. This year the average nationally was 9.44%, significantly below PacifiCorp's request of 10.2%. The following chart reflects this.

CUB Figure 2



[12] UE 374 – PacifiCorp/2200/Bulkley/11.

PacifiCorp presents a graph of 54 ROEs that have been granted since 1/1/2018.[13] Only three times (5.6%) have Commissions granted ROEs above what PacifiCorp is asking, while 51 times (94%) Commissions have granted ROEs that are less than what PacifiCorp is asking.

Q. Should the Commission consider the impact of COVID-19 when setting ROE?

A. Yes. Setting a utility's ROE is normally a two-step process. The first step is to identify a reasonable range for earnings. The second step is to consider what point along this reasonable range should be selected for the targeted, authorized earnings level.[14] COVID-19 has the potential to affect both areas.

Q. How could it affect the reasonable range of ROEs?

A. ROEs are supposed to compensate shareholders at a level that is comparable to other enterprises with similar risk.[15] The pandemic has the potential to cause wider economic distress and could drive down earning for investments in general. One effect could be that investors find stable utility stocks to be safe havens and this would put downward pressure on ROE ranges due to decreased risk.

Q. How would it affect the choice of the authorized earnings level?

A. The Commission has authority to set the ROE at a reasonable level. Because the entire range of earnings defined in the first step is reasonable, the Commission has authority to set it anywhere within the range. An important element of the Commission's authority is to balance the interests of customers and shareholders.[16] Under normal circumstances, a Commission might pick a level that is at the

[13] UE 374 – PacifiCorp/2200/Bulkley/10.
[14] *See* OPUC Order No. 08-487 at 5.
[15] *Bluefield Water Works and Improvement Company v. Public Service Commission*, 262 US 679 (1923).
[16] OPUC Order no. 08-487 at 101.

midpoint of the reasonable range, but some circumstances might have a Commission choose a level that is less than the midpoint. For example, if a utility was seeking a huge rate increase that created rate shock to customers, the Commission could reasonably balance the interests of shareholders and customers by picking a targeted ROE that was near the bottom of the reasonable range, so while the utility still had expectations of reasonable earnings, rate shock was minimized. In a circumstance like the present, when economic conditions have led to significant unemployment among customers, CUB recommends that the Commission pick a targeted earnings level that is in the lower half of the reasonable range, recognizing that customers are in more difficult financial circumstances than shareholders and a lower point will create a better balance of interests between customers and shareholders. The Commission should not set the ROE at a level that is below the reasonable range, but under current conditions it should look to the lower half of the reasonable range

Q. Does CUB have a specific ROE recommendation?

A. CUB believes that utility ROEs approved in Oregon and around the country demonstrate that PacifiCorp's current authorized ROE is inflated and should be lowered. In light of the effects of the COVID-19 on utility customers, CUB recommends that the Commission grant the Company a ROE no higher than 9.4 %.

C. Proposed Changes to the PCAM

Q. Do you have a response to PacifiCorp's Reply Testimony concerning the elimination of the deadbands and earnings test associated with the current PCAM?

A. Yes. PAC witness Mr. Graves criticizes the five principles the Commission established to evaluate the PCAM, while simultaneously trying to redefine those principles. I will show that the Commission's principles are reasonable, were thoughtfully articulated, and should continue to be applied. I respond to Mr. Graves argument that the Commission should ignore the impact of the COVID-19 crisis on customers. Finally, I will discuss the impact approving PacifiCorp's proposal will have on utility regulation in Oregon.

The core element of Mr. Graves testimony is that a utility should not take risk for factors that are outside of its control. To understand why this is a flawed argument, this testimony will discuss business risk, debt versus equity, prices versus costs, and the regulatory compact.

1. *Business Risk*

Q. Please explain what you mean by business risk.

A. PacifiCorp is a business. It sells a product to customers for a price that is available to the customer before the customer makes a purchase. Most businesses operate under a business plan that attempts to ensure that the price of the product will recover the cost of the product. But all businesses are subject to changes in production costs, and changes in demand from a variety of causes. For example, lets evaluate the business risk of a ski shop. During a cold winter with snowy conditions, the Company will experience high demand for its product and over recover its costs. During a warm winter, the ski shop will reduce its sales and limit its ability to cover its fixed costs. Compare this to PacifiCorp. During a cold winter, PacifiCorp's electric sales for space heating will increase, which will lead to the utility over-recovering its fixed costs. During a warm winter, reduced sales will lead to it under-recovering its fixed costs.

This is business risk. It is not unusual for a private enterprise. It is not unique to utilities. Circumstances arise where a business plan's forecast of costs and demand may not fully recover all costs and provide the full profit that it projects. While PacifiCorp is asking for protection from business risk in multiple arenas, nearly all businesses are subject to some form of business risk. Regulation reduces business risk for electric utilities. For example, when the COVID-19 crisis hit, PacifiCorp and other utilities filed deferrals to ensure that they can recover costs—such as bad debt—associated with the virus whereas many retail businesses shut down. Most businesses would love to live in a world where the only risks they face are the risks that are under their control, but that is not the world we live in. While regulation recognizes that utilities provide an essential service and protects them from some business risk, that protection cannot be without limit. It important to note that the Company's proposal would shift all the business risk associated with net variable power costs to customers. The Company's proposal in regards to the PCAM is just another in a long line of proposals—such as the COVID-19 deferral—to shift business risk to customers.

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2. *Debt versus Equity*

Q. Please discuss the role of equity and debt as it relates to business risk?

A. One of the important tools that allow businesses to absorb business risk is the role of shareholders and the difference between equity and debt. Shareholders provide equity which acts as a shock absorber and allows a company to manage business risk. When a company finances with debt there is an obligation to pay a specific interest rate on that debt and to maintain a specific payment schedule. If the Company fails to meet its payment obligation, it will go into default. Equity is different. While an equity shareholder might expect a specific dividend, there is no guarantee. In exchange for no guarantee of payment, the cost of capital from equity is higher than debt. The higher the company's equity capitalization the more business risk it can absorb. Conversely, a business that is highly leveraged with debt may not have an adequate balance sheet and may be limited in the amount of business risk that can be absorbed.

This role of equity in allowing a utility to absorb business risk is important to recognize, because customers pay for it. PacifiCorp's case requests a cost of equity of 10.2% and a cost of debt at 4.774%. Equity, however, comes out of net earnings which are subject to federal and state corporate income. The federal rate is 21% and the state rate varies across PacifiCorp's service territory. Assuming the composite state rate of 5%, then the pretax earnings that customers would have to pay to earn the Company's requested ROE would be is around 12.8%. On $1 billion of capital investment, the difference in financing cost is vast. The cost of debt would be $47.7 million and the pretax cost of equity would be $127 million. Customers clearly pay a premium for the value of equity shareholders and their ability to absorb risk.

This was clearly recognized in the design of the PCAM. The deadbands under the Commission's approach were originally set based on the shareholder equity that was used to finance the utility. The Commission first established the upper threshold of the earning band at 150 basis points of equity, not $30 million. The deadband was established to identify the level of normal business risk Oregon expected utilities to absorb based on the amount of equity investment in the utility.[17]

If normal business risk falls on customers, and the utility is only subject to the risk of prudence disallowances for items under its control, then customers are paying millions in equity costs, but not receiving the full benefit of equity investment. It would be better to change the capital structure so the utility is financing more heavily with debt or even create a publicly-owned utility which can use low-cost tax-exempt public debt and has no equity component.

Q. PacifiCorp argues that having more leverage and less equity in its capital structure could impact its credit rating. Would this happen if the Commission reduced equity in the capital structure?

[17] OPUC Order No. 07-015 at 26.

A. This is a possible outcome. Credit agencies recognize that equity absorbs business risk and helps ensure that debt obligation is met. Credit agencies also recognize that regulation can place this risk on customers rather than shareholders. But even if bond ratings were downgraded and a utility's cost of debt increased, the cost of debt would still be well below the pre-tax cost of equity. PacifiCorp argues that lowering its equity percentage could impact its credit rating. It does not argue that lowering its equity percentage will raise the overall cost of financing capital investment.

Q. How does PacifiCorp's credit rating compare to peer utilities in the region?

A. The Company's present credit rating is similar to other peer utilities in the region. The following table is highlighted to provide clarity, but the information therein is not confidential.

CUB Table 2

Utility	State (Headquarters)	Credit Rating (Moody's)
PGE	Oregon	A3
Puget Sound Energy	Washington	Baa1
Avista Corporation	Washington	Baa2
Idaho Power	Idaho	A3
PacifiCorp	Oregon	A3

Moody's Credit Rating Hierarchy
Aaa
Aa1

Aa2	
Aa3	
A1	
A2	
A3	<- Pacific Power's current rating.
Baa1	< - A notch downgrade rating.
Baa2	
Baa3	

3. *Prices Versus Costs and the Regulatory Compact*

Q. Please explain the role of prices versus costs.

A. A healthy business must set its prices at a level that covers its costs and allows the company to earn a profit. The business risk associated with this is that costs, sales volumes, or unexpected events create a situation that prices no longer fully recover costs and expected profits. But businesses do not know the future when they set prices. Prices are set without full knowledge of the future and, in normal competitive markets, businesses do not have the ability to go back recover costs after all business risks are known.

Q. What is the regulatory compact?

A. Vertically integrated electric utilities are not normal businesses. States grant them monopoly power in exchange for the state having a regulatory role in setting rates (prices). The primary responsibility of the regulator is to protect monopoly customers from the monopoly power to set excessive rates. A non-regulated business is limited in the prices they can charge by the competitive market. A monopoly utility does not have the constraint of a competitive market, so the regulatory system is supposed to bring the discipline of the market to the monopoly. The core responsibility of the Commission is to set just and reasonable rates. This means that rates allow for the utility to recover its costs and earn a reasonable return on a prospective basis. It also means that rates must be "set at a level sufficiently low to avoid unjust and unreasonable exactions" to protect customers.[18]

PacifiCorp, on behalf of its shareholders, Berkshire Hathaway, would rather have regulators focus on retroactive cost recovery than prospective rate setting. In the case of PacifiCorp, rates have allowed it to recover it costs and earn a reasonable return, as I discussed in Opening Testimony.[19] But the utility can identify cost elements that were not recovered. Establishing mechanisms that allow the utility to retroactively recover costs that were inaccurately forecast—such as deferred accounting applications—reduces business risk. By applying this selectively, a utility can reduce business risk and earn above its targeted return on equity.

Q. Please explain what you mean by applying this selectively.

A. As demonstrated in CUB's Opening Testimony, in spite of under-recovering power costs, the Company has consistently been earning a reasonable return on equity. This means that while power costs have been higher than forecast, there are other offsetting costs that are lower than forecast. The Company has complete access to

[18] OPUC Order No. 08-487 at 5.
[19] UE 374 – CUB/100/Jenks/32.

its books of accounts. Yet, it has not identified those offsets, nor has it proposed a mechanism to fix the over-recovery of those costs. In Opening Testimony, CUB demonstrated that PacifiCorp has earned on average more than 50 basis points above its authorized ROE since 2014.[20] If PacifiCorp's approach to dollar-for-dollar retroactive recovery of power costs were in place during this time, the Company would have consistently earned above its authorized rate of return by even more. From the Company's viewpoint cost recovery will have improved, but overall rates will be above a just and reasonable level.

4. *PCAM Principles*

Q. Did PacifiCorp respond to the five principles that the Commission established to evaluate PCAMs?

A. Yes. Mr. Graves lists the five conditions and then attempts to dismiss them or parse them in a manner that is inconsistent with the establishment of these principles. PacifiCorp's attempt to remove the deadbands and earning test and guarantee dollar-for-dollar recovery of power costs violates all five principles. The five principles are found on the following page:[21]

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[20] UE 374 – CUB/100/Jenks/32
[21] OPUC Order No. 12-493 at 8.

> **1. any adjustment under a PCAM should be limited to unusual events and capture power cost variances that exceed those considered normal business risk for the utility;**
>
> **2. there should be no adjustments if the utility's overall earnings are reasonable;**
>
> **3. the PCAM's application should result in revenue neutrality;**
>
> **4. the PCAM should operate in the long-term to balance the interests of the utility shareholder and ratepayer;**
>
> **5. the PCAM should provide an incentive to the utility to manage its costs effectively.**

Q. How did PacifiCorp address the first principle?

A. Mr. Graves argued that the term "unusual" is not well-defined and is not a "sufficient basis for excluding prudent costs."[22] Instead he suggests the Commission should reinterpret this principle using the words "uncontrollable" and "unpredictable."

Q. What is your response to Mr. Graves assertion?

A. The Commission knew exactly what it was doing when it established this principle. It was well-defined. The definition is in the principle itself: unusual events "*that exceed those considered normal business risk for the utility*." Normal business risk is defined by the deadband. The Commission intended to limit recovery of under-

[22] UE 374 – PAC/3000/Graves/6.

forecasted net power costs to 150 basis points of ROE.[23] The Commission believed that equity allowed a utility to absorb normal business risk. The more equity, the more business risk that the utility could absorb. Because the benefit of equity for customers is it allows the utility to absorb risk in a manner that debt does not, this makes a great deal of sense. There is a normal business risk that customers pay the utility to absorb. An unusual event is one that goes beyond this amount.

As to his claim that this is not a "sufficient basis for excluding prudent costs" misrepresents Oregon's rate setting process. Prudently incurred costs are not being excluded. Prudently incurred costs are being forecast. The rate setting process establishes rates on a prospective basis rather than a retroactive basis. Our forecasts attempt to include all prudently incurred costs on a weather normalized basis.

His suggestion that the Commission should instead use the word "uncontrollable" and "unpredictable" misreads the history of the mechanism. Mr. Graves states that these principles were first articulated by the Commission in 2005 when PGE's requested a Hydro-only PCAM. Hydro conditions are outside of the Company's control. The Commission clearly intended to apply a principle related to unusual (outside of normal) business risk to a cost that was outside of the Company's control and unpredictable.

[23] OPUC Order No. 07-015 at 26

It is also not reasonable to say that these costs are not under the utility's control. The utility cannot control the weather, but the utility can control what resources and contracts it has in place to meet peak weather events. The utility clearly has control over the coal contracts and the operations of its subsidiary coal mines. The utility every day must decide which resources to commit in bilateral day-ahead arrangement and which resources to hold back from the EIM. The utility develops its natural gas procurement policy. The utility has a degree of control over its generation plant operations. The utility controls its maintenance schedule. While the utility does not control the wind, the Company selects the sites of its wind resources based on its analysis of expected wind output. The Company selects the sites of its solar resources. The utility controls the terms of its contracts for wholesale power.

Q. Does the Company hire employees to manage net variable power costs?

A. Yes.

For example, the job responsibilities of the [redacted] are the following:

- [redacted].
- [redacted]
- [redacted]

- [redacted]
- [redacted].[24]

CUB presents this employees job description to highlight that the Company does have a degree of control over net variable power costs elements. The Company uses its trading strategy and judgement [redacted].[25]

Q. How does the Company address the second principle?

A. The Company suggests that it is “neither well defined (as to how much of a deviation is material) nor productive in terms of better regulatory oversight.”[26] I disagree that this is not well defined. Earnings tests have been applied to deferrals for decades. Earnings test are sometimes established at the authorized ROE level from the last rate case and sometimes apply a band around that ROE that represents a reasonable level. With the PCAM, the Commission has applied a band around authorized earnings that it believed represented reasonable earnings. The reason for this is simple. If the rates that have been established allow the utility to earn a reasonable return, the Commission has met it responsibility to establish rates that allow for recovery of prudently incurred costs and allow the Company to earn a reasonable return. A true up when a utility has

[24] CUB Exhibit 403 CONF – An excerpt from PAC data response to CUB DR 13.
[25] CUB Exhibit 403 CONF.
[26] UE 374 –PAC/3000/Graves/8.

already earned a reasonable return has the potential to create rates that are no longer just and reasonable. It is not clear as to what Mr. Graves means when he says "better regulatory oversight." The primary concern seems to be that the Company is not allowed to retroactively adjust rates when it has already had reasonable earnings. The PCAM is a good example of good regulatory oversight designed to protect customers of a monopoly.

Q. How does the Company address the third principle?

A. The Company dismisses it by stating that it would be inappropriate in resource expansion circumstances and Mr. Graves believes "it does not apply here."[27] First, the Commission said this applies to power cost adjustment mechanism, so it does apply. It is important to recognize that the Commission was not saying that net power costs are revenue neutral, but that retroactive recovery mechanism should be revenue neutral. The reason that the deadband is assymetrical is because non-normalized power cost excursions of higher cost than forecast potentially have a higher magnitude than power cost excursions of lower cost than forecast. The mechanism was designed so the transfer of dollars changing between shareholders and customers would even out over time. The Commission, by design, was trying to create a mechanism that did not change the allocation of risk from our normal prospective rate setting.

His suggestion that this principle would not apply to resource expansion makes little sense. Resource expansion, like net power costs is charged to customers on

[27] UE 374 – PAC/3000/Graves/7.

a prospective basis and is not revenue neutral. But because we forecast load on a normalized basis there is no guarantee that the utility will recover it prudently incurred cost associated with depreciation and return on undepreciated investment. If load is below forecast, the utility under-recovers its fixed costs, including resource expansion cost. If load is above forecast, the utility over-recovers its resource expansion cost. True-ups are revenue neutral for resource expansion investments, because they are zero on both sides of the equation.

Q. How does the Company address the fourth principle?

A. The Company appears to be misstating the fourth principle. Mr. Graves states that the fourth principle is that the PCAM operate "in ratepayer interests" and claims that eliminating deadbands and the earnings test is in "harmony with customer interests." But what the fourth principle says is that the PCAM "should operate in *the long term* to *balance* the interests of utility shareholders and customers." The key to understanding this principle is the phrase "in the long term" and the word "balance." The Commission was trying to establish a mechanism that was only triggered in unusual circumstances and would be revenue neutral. However, because when it is occasionally triggered it shifts money from customers to shareholders or vice versa, the Commission was saying that it needs to stay in place for the long term. The balance comes over time. If it is triggered once every ten years, it could take decades for the balance to become apparent.

Q. How does the Company address the fifth principle?

A. The fifth principle is that a PCAM should provide an incentive to the utility to manage its costs. Mr. Graves largely dismisses this principle, stating that no party has identified "any kind of operational performance that is believed to be enhanced" because of the PCAM.[28] Essentially, he is arguing that no party is pointing to anything that the Company would have more poorly managed if this incentive had not been in place.

While this may be true, PacifiCorp has not demonstrated that it would have invested differently if the Commission had set its ROE at 6%. There are two broad incentives that have been part of Oregon utility regulation since at least the 1980s. The first is the incentive to invest capital, because their profits (ROE) largely come from investing capital. Oregon regulation has, in fact, been criticized for being overly dependent on this incentive which may be causing utilities like PacifiCorp to build large generating assets rather than enter into Purchase Power Agreements. In fact, the Commission found that there was an inherent bias in utility resource procurement that "favors utility ownership of generation assets over Purchase Power Agreements."[29] The second incentive is to control costs. This incentive is created by having rates set on a prospective basis and allowing utilities to retain the difference between forecast and actuals. A utility that controls its costs is allowed to earn above its authorized ROE.

[28] UE 374 – PAC/3000/Graves/13.
[29] OPUC Order No 11-001 at 1.

This has been true since the 1980's. In the 80's and 90's utilities did not have PCAMs or TAMs – all costs were set in general rate cases. These happened every few years. A utility that could innovate and reduce costs would benefit from it. A large part of net power costs at the time was hydro power. The three regulated electric utilities all had their own hydro facilities and PGE and PacifiCorp had large contracts for Mid-C hydro. Hydro varied a great deal from year-to-year and the volume of hydro was largely outside of the utilities control. Without a PCAM mechanism, utilities such as Pacific Power, Portland General Electric and Idaho Power were able to manage the business risk, obtain financing for capital investments and meet the needs of customers. And to the degree these utilities could find efficiencies which reduced costs, these were retained as net earnings until the next general rate case.

This incentive to control costs exists for all energy utilities. It is built into the structure of power cost recovery for the electric utilities and it is part of the Purchased Gas Adjustment for gas utilities – though CUB recognizes that the level of risk sharing for gas utilities in the PGA is smaller, but this is due to the Commission linkage of risk sharing to equity investment (rate base) and gas utilities have very limited capital investment in gas supply.

Q. What would happen if this incentive is not in place?

A. First, if the Commission removes this incentive to control costs from PacifiCorp, all other energy utilities will likely file rate cases next year asking for the cost control incentives applied to them also be removed. All utilities have opposed these incentives and asked that they be removed and the Commission has declined to remove them. PGE, PacifiCorp, and Idaho Power all would have preferred a PCAM without any incentives to control costs and advocated for such mechanisms. In 2015, PGE and PacifiCorp jointly asked the Commission to change the mechanism and remove the incentives.[30] In 2008, the Commission rejected a proposal by gas utilities to abolish the cost control incentive built into the Purchased Gas Adjustment (PGA) mechanism stating that the current mechanism "provides a simple, direct incentive for the LDCs to minimize their gas costs."[31] If the Commission removes this incentive for PacifiCorp, PGE, Idaho Power, Northwest Natural, Avista and Cascade will all likely file cases to remove this incentive from their mechanisms. CUB believes that there are higher priorities for the Commission to address next year including the effects of the COVID-19 pandemic and its economic effects and implementing the Governor's Executive Oregon on Greenhouse Gas Reductions.

The second effect of removing this incentive is that Oregon will be moving away from performance-based ratemaking (PBR), before it even explores PBR as it committed to do in its SB 978 Legislative Report.[32]

Q. What is your recommendation?

[30] *See* UM 1662.
[31] OPUC Order No 08-504 at 16.
[32] OPUC, SB 978 Actively Adapting to the Changing Electricity Sector – SB 978 Report at 18.

A. The Commission should reject the Company's proposal to alter the PCAM. Any proposed changes should be considered in a multi-party docket, such as an investigation into PBR.

D. Wheeling Revenues

Q. The Company responded to CUB's proposal to move Wheeling Revenues to the TAM by claiming that Wheeling Revenues are an offset to transmission assets, and therefore the matching principle says these costs should be in a General Rate Case. How do you respond?

A. I disagree. While it is true that capital investment in transmission assets is a general rate case issue, that does not mean that annual sales of transmission need to be in a general rate case. The capital investment associated with power supply, whether it be a coal plant, or a wind farm, is also handled through a general rate case, but wholesale power sales from those assets, whether through bilateral arrangements or through EIM, are a net power cost issue in the TAM. In addition, because transmission rates are set annually by FERC, the forecast of Wheeling Revenues for 2021 is not a reasonable forecast of Wheeling Revenues for 2022. A deferral will be required to take into the new transmission rates. The move toward more regionalization of markets, such as the move to an organized day-ahead market could significantly change Wheeling Revenues. Wheeling Revenues are also related to net variable power costs. The dispatch of system resources to meet load requires transmission. The transmission that is available to be sold to third parties is what is available after dispatch of PacifiCorp's system.

Finally, CUB again notes that Utah found that Wheeling Revenues should be an offset to Wheeling Costs which is a net power cost.[33]

Q. PacifiCorp claims that the Company was in a FERC rate case during the last general rate case and a deferral was established because the outcome of that case was unknown. They are not in a rate case today, so why do you claim that a deferral will be necessary?

A. The Company now has formula rates. This means that rates are reset every year – essentially there is a new rate case every year. The forecast in this rate case may be a reasonable forecast for 2021, but rates will be different in 2022 and a new deferral will be necessary. In addition, fundamental changes in the marketplace, such as a day-ahead market will likely significantly change both Wheeling Revenues and Wheeling Costs.

It is important to recognize that the primary purpose of CUB's proposal was to improve ratemaking. Wheeling Revenues are variable and fit well within the TAM which is an ongoing automatic adjustment clause. CUB believes utilizing this mechanism is preferable to a series of annual deferrals. CUB continues to urge the Commission to alter the TAM Guidelines—which is appropriate in a general rate case year—to include Wheeling Revenues in the annual TAM forecast.

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[33] UE 374 – CUB/100/Jenks/6.

E. Jim Bridger Units 3 and 4 SCRs

Q. Has CUB reviewed the testimony of other parties regarding PacifiCorp's decision to invest in SCRs at Bridger Unit 3 and Bridger Unit 4?

A. Yes. CUB reviewed the Reply Testimony of PacifiCorp and the testimony of Sierra Club and Staff. In addition, we have reviewed data requests from those parties, as well as ones that CUB submitted. After review, CUB finds that that the decision to invest in the SCR at the two Bridger units was imprudent. Further, upon additional review, CUB has additional concerns about the level of cost that PacifiCorp is assigning to customers in this proceeding.

1. *Imprudence of the Investment*

a. Background

Q. CUB raised concerns about the prudence of the Bridger SCR investments in Opening Testimony. Did the Company address your concerns about the prudency of its decision to invest in the SCRs at Bridger Unit 3 and Bridger Unit 4?

A. The Company's response was not satisfactory to address CUB's concerns. The Company changed its testimony regarding what it considered as an alternative before making the Bridger investment. In addition, after examining the Company's Reply Testimony and Sierra Club's testimony and data requests, CUB has concerns whether the Company properly accounted for the flexibility that is allowed under Regional Haze Rules. Finally, CUB remains concerned that the Company's attempt to dismiss the Oregon useful life as irrelevant ignores the clear direction the Commission gave the Company when it refused to extend the life of the Bridger units. CUB continues to believe the Company's decision to invest in the Bridger SCRs was imprudent.

Q. What did the Company change in its testimony concerning the alternative to the Bridger SCRs?

A. In its Opening Testimony, PacifiCorp stated that they made the decision to install the SCRs at the Bridger units in May 2013[34] after considering two options as alternatives in the Wyoming Certificate of Public Convenience and Necessity proceeding: early retirement in January 2016 and January 2017 or conversion to natural gas in March 2016 and March 2017.[35] In its Reply Testimony, the Company says that it considered two additional alternatives: retiring the Units in 2020 and 2021 and retiring the Units in 2022 and 2023, pointing to the Oregon 2013 IRP as a place where these alternatives were modeled.[36]

Q. Do you believe this is accurate?

A. Only to a degree. I believe the Company when it says that it made the decision to proceed based on the Wyoming case and that it only considered two alternatives at that time. While I agree that the Company modeled other alternatives in the 2013 Oregon IRP, I do not believe that the Company was seriously considering alternatives to the SCRs at that time. For example, it did not engage in discussions with environmental regulators concerning the flexibility that exists in the Regional Haze Rules. It did not raise this issue in Wyoming where the plant is located. Instead it chose some future retirement dates to model in Oregon

[34] UE 374 – PAC/700/Link/87.
[35] UE 374 – PAC/700/Link/91.
[36] UE 374 – PAC /2300/Link/13.

where it had been criticized for not considering retirement. CUB was active in PacifiCorp IRPs at the time, and believed that the Company did not seriously consider committing to a future shut down date as an SCR-alternative for the Bridger units.

Q. **Please explain.**

A. Consider the 2011, and 2013 PacifiCorp IRPs. These came after PGE had successfully shown that committing to a future retirement date could substantially reduce environmental compliance costs and save customer money with the announcement to shutter its Boardman coal plant. PacifiCorp took multiple IRP cycles to even consider this approach. Avoiding a Regional Haze Rule analysis like PGE's for several years allowed the Company to invest billions in environmental retrofits without seriously considering the alternatives. By the time PAC began seriously considering coal plant retirement as an alternative to environmental retrofits, the Company had completed most of its planned investments, which created large returns for shareholders. Consider the following chart from PacifiCorp in 2011:

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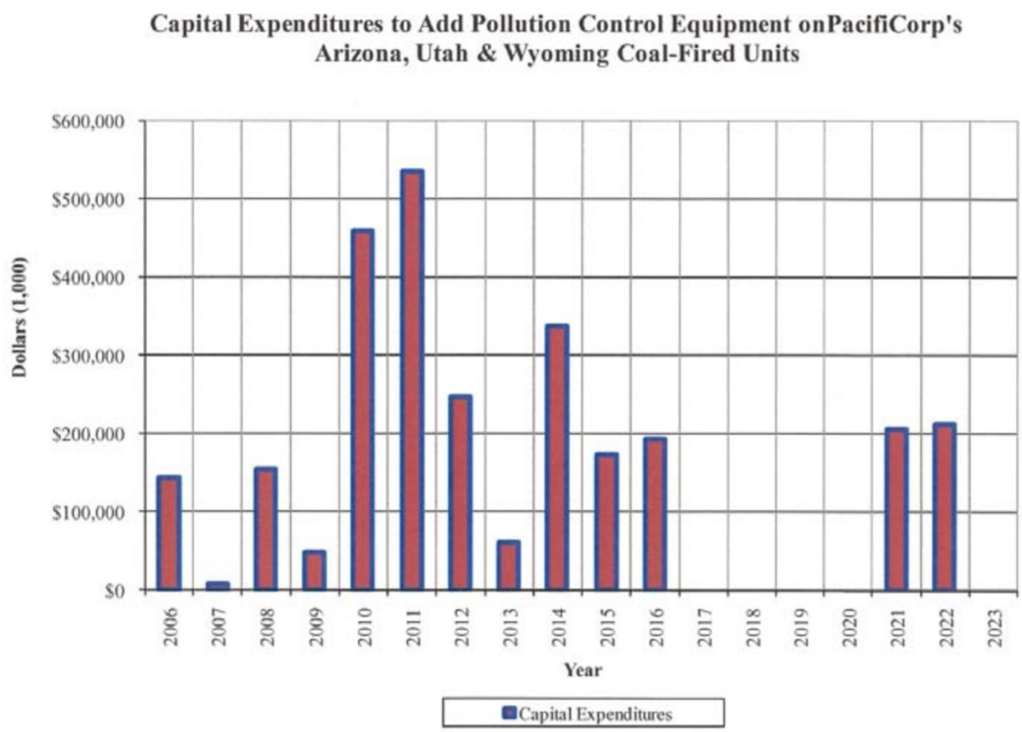
CUB Figure 3: Capital Expenditures on Coal-Fired Units by Year [37]



The Bridger Units in 2015 and 2016 were the end of a cycle that saw the Company spend billions on coal plant retrofits. PacifiCorp spent $1.2 billion on coal plant retrofits before 2011.[38] In 2011, Cathy Woolums, Senior Vice President and Chief Environmental Counsel of MidAmerican Energy Holdings Company testified to Congress that PacifiCorp expected to spend an additional $1.57 between 2011 and 2020[39] for a total clean air capital investment of $2.7 billion which, including O&M, would cost customers $4.2 billion or $360 million

[37] LC 52 – CUB Opening Comments *available at* https://edocs.puc.state.or.us/efdocs/HAC/lc52hac132518.pdf.
[38] PacifiCorp Environmental Update, June 1, 2011
[39] Testimony of Cathy S. Woolums, Senior Vice President and Chief Environmental Counsel, MidAmerican Energy Holdings Company, Committee on Environment and Public Works, United States Senate, June 15, 2011.

per year. The plan to construct and install environmental retrofit capital investments like the Bridger 3 and 4 SCRs was in place well in advance of the Commission's consideration of these investments in an IRP.

b. 2011 IRP

Q. How were clean air investments considered in the 2011 IRP?

A. First, stakeholders had to work to even get clean air investments considered. In the 2011 IRP, after already spending more than $1 billion on these investments, PacifiCorp told the parties that clean air investments were not an IRP issue.[40] At the same time the Company's position in rate cases was that coal retirement was an IRP issue not a general rate case issue.[41] The Company did not see clean air investments as resource decisions, since it did not seriously believe that retiring a plant was an alternative to clean air investments. It did admit that retiring a coal plant would be a resource decision and be analyzed in an IRP, but this had nothing to do with clean air investments.

Without IRP review of clean air investment, the only review of these capital investments was during a general rate case, after they had been made. This meant that piecemeal sections of environmental retrofits were being reviewed as the sections became used and useful, but the prudency of the overall decision to retrofit was not examined. For example, to meet Regional Haze compliance standards, SCRs are paired with Low-NO_x burners (LNB) with separate overfired

[40] LC 52 – CUB Opening Comments, page 9.
[41] LC 52 – CUB Opening Comments, page 8-9.

air (OFA).[42] PacifiCorp's approach allowed it to ask for approval of LNB with OFA in one rate case and an SCR in another, and avoid a review of the entire Regional Haze investment at a coal unit.

Ultimately, the Commission required the Company to supplement its 2011 IRP filing with a coal utilization study. The study was flawed in that it assumed all coal investments before 2015 were sunk costs that could not be avoided, and these costs had to be recovered from customers to close the plant. But these pre-2015 costs included the costs to meet 2015 compliance deadlines, which meant that the Company was examining what would happen if it invested to meet clean air requirements and then closed the plant anyway.[43] The primary progress made in the 2011 IRP was that clean air investments were established as a legitimate item for IRP review for the first time.

c. 2013 IRP

Q. How were clean air investments considered in the 2013 IRP?

A. The 2013 IRP was the first PacifiCorp IRP that included review of Bridger environmental retrofit investments. While there were improvements in how the Company examined Regional Haze investments, CUB did not believe that the Company made a serious effort to investigate alternatives to the Bridger SCRs.

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[42] LC 57 – CUB Opening Comments, page 17 *available at* https://edocs.puc.state.or.us/efdocs/HAC/lc57hac82941.pdf.
[43] LC 52 – CUB Reply Comments *available at* https://edocs.puc.state.or.us/efdocs/HAC/lc52hac15456.pdf.

Q. What was the Commission's decision related to the Bridger SCRs?

A. The Commission reached four conclusions:[44]

1. The Company had failed to demonstrate that the SCR was the least cost option:

> First, some of the modeled alternatives suggest that the installations of SCRs are not the lowest cost resource option. For example, as described on page 4 of Staff's Final Comments dated January 10, 2014, alternative D runs demonstrate that it is more economical to retire Bridger 3 and 4 than to install the SCR equipment. Based on the information we currently have, we cannot dismiss these results as unrealistic or unreasonable.

2. PacifiCorp's analysis was incomplete:

> Second, we concur with Staff that there are gaps in PacifiCorp's analyses. As Staff notes, PacifiCorp did not consider the potential tradeoffs between coal plants to identify the most cost effective compliance options from a state or fleet perspective. Additional analysis on these issues would have resulted in more information for us to make an informed decision on acknowledgement.

3. There was a lack of information necessary to render a decision:

> Third, Staff and other participants have raised several other specific issues related to the merit or lack of merit of installing SCRs at Bridger 3 and 4, such as the impact of retirement on reliability, inter-temporal and fleet trade-off analysis between units, or the impact of retirement on future transmission investments. However, we lack the necessary information in this proceeding to weigh these issues and they will be more thoroughly investigated in a future rate case proceeding.

4. PacifiCorp is already making the investment regardless of the Commission's decisions so acknowledgement is irrelevant:

> Finally, PacifiCorp is going ahead with the investments in installing SCRs regardless of our decision in this proceeding. We will undertake a thorough and fair review of the prudence of PacifiCorp's decision in a future rate case proceeding.

[44] OPUC Order No. 14-242, page 8-9

In this proceeding, PacifiCorp is pointing to its IRP analysis to support the prudency of the Bridger SCR investments, without addressing the concerns that the Commission raised in its 2013 IRP Order. Nowhere in the record does the Company address the conclusions the Commission reached. If the analysis was incomplete and failed to demonstrate that the SCR was the least cost at the time of the 2013 IRP, then that same analysis does not meet the burden of proof necessary to demonstrate that this is a prudent investment.

Q. What were CUB's concerns with the Jim Bridger SCRs in the 2013 IRP?

A. CUB was "encouraged that PacifiCorp has finally acknowledged that there is enough flexibility under the Regional Haze Rules to consider an early closure alternative."[45] However, this analysis was applied to a small number of coal units after hundreds of millions of dollars had been spent to retrofit other units. PacifiCorp's analysis was insufficient. CUB was concerned that it focused on the SCR instead of Regional Haze cost effectiveness, it did not choose the appropriate dates for retirement, and it was not engaged in discussion with environmental regulators about the level of flexibility that would be allowed. If it had, it likely would have been able to identify a least cost path that was lower cost than installing an SCR. Again, the Company sought piecemeal acknowledgement of its environmental retrofit investments rather than seeking stakeholder input and Commission approval on a sweeping Regional Haze compliance plan. PacifiCorp's planning was flawed.

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[45] LC 57 – CUB's Opening Comments at 13 *available at* https://edocs.puc.state.or.us/efdocs/HAC/lc57hac82941.pdf.

Q. Explain how the analysis focused on the SCR rather than Regional Haze Cost Effectiveness?

A. The Regional Haze Rules require the Best Available Retrofit Technology (BART) that can be installed and remove NO_x and SO_2 emissions on a cost-effective basis. In the EPA's view, BART is a set of both technologies and actions. A Selective Catalytic Reduction combined with Low NO_x burners and overfire air (SCR plus LNO and OFA) is considered BART in this and other cases. Because PacifiCorp went ahead and installed the LNO and OFA ahead of the SCR, its IRP review was only considering one element of BART. By going ahead and installing LNO and OFA before the SCR, PacifiCorp hoped to limit the Regional Haze review to just an SCR, which would not have been cost-effective on a stand-alone basis. However, this strategy obvious failed as the EPA continued to view an SCR with LNO and OFA as BART. The EPA evaluates pollution control on a dollar per ton of pollutants removed over the useful life of the control equipment. On this basis, a stand-alone SCR costs more than twice what an SCR with LNO and OFA costs. This led PacifiCorp to focus on cost-effectiveness limits that were well above the EPA's. For example, the EPA identified the cost of an SCR with LNO and OFA as $2393/ton of pollution removed.[46] PacifiCorp identified the cost of an SCR alone as $5869/ton, more than twice as much.[47]

Q. How did this affect PacifiCorp's analysis?

A. This approach made it difficult to establish the future closure date that should be modeled as an alternative to installing SCR in 2015 and 2016. Rather than

[46] LC 57 – CUB Opening Comments, page 14.
[47] LC 57 – CUB Opening Comments, page 14.

investing in environmental retrofits, an emitter can comply with BART by announcing early closure of the plant, as PGE did with Boardman. By doing so a plant operator can establish an emissions reduction plan that is superior to BART controls and it can ensure that the BART controls no longer meet the $ton/removed cost-effectiveness test. While EPA does not have a bright line that says that a cost of more than $3000/ton is no longer cost effective, PacifiCorp should have been following Regional Haze decisions around the country and should have had an idea where this threshold would be. PacifiCorp hindered its analysis because all its pollution control analysis was above the EPA's cost effectiveness threshold because the cost of the stand-alone SCR on a dollars/ton is so much higher than the cost of the BART (SCR with LNO and OFA). Again, this is because it had already invested in the LNO and OFA. The dates the Company chose to model the closure were not based on an analysis of what date represents the likely cut off between cost effective and non-cost-effective BART controls. Instead, it was an arbitrary date that was chosen because CUB and other parties had been demanding that the Company analyze a phase out as an alternative to pollution control. The analysis was flawed and insufficient.

Q. How did PacifiCorp choose the wrong years to model as the closure years?

A. CUB Exhibit 404 is CUB's Confidential Opening Comments in the 2013 IRP. These comments describe CUB's concerns with PacifiCorp's alternative closure date choice of 2020 for Bridger 3 and 2021 for Bridger 4. [redacted]

[redacted][48]

More importantly, because there is not a clear line that separates when the EPA will allow retirement instead of a retrofit, the Company should have engaged in discussions with EPA to identify what was reasonable. Modeling the flexibility that regulators may apply in a rulemaking without establishing their approach in applying that flexibility is an exercise in guesswork. In its Reply Testimony, the Company now cites December 2013 as the date that it made the final retrofit decision.[49] By this date, the Company was in discussions with EPA concerning how long it could operate Dave Johnston without pollution control.

Q. Please explain.

A. In January 2014, EPA issued its final Federal Implementation Plan (FIP) for Wyoming Regional Haze. The EPA offered PacifiCorp a choice that would allow it to avoid installing an SCR within five years if it committed to retiring the plant

[48] CUB Exhibit 404 CONF. CUB Exhibit 404 represents the confidential pages from its LC 57 Opening Comments. The remainder of the comments are publically available at https://edocs.puc.state.or.us/efdocs/HAC/lc57hac82941.pdf.

[49] UE 374 – PAC/2300/Link/5.

by December 31, 2027. The EPA met with PacifiCorp on October 31, 2013 to discuss this. EPA specifically asked if PacifiCorp was:

> asking for EPA to include an enforceable requirement in the FIP for Dave Johnston Unit 3 to shut down in 2027, and for EPA to make a BART determination based on that limited remaining useful life. PacifiCorp confirmed that it did want EPA to include an enforceable requirement in the FIP for PacifiCorp to shut down Dave Johnston Unit 3 by December 31, 2027 and to make a BART determination accordingly.[50]

This statement meant that while PacifiCorp may not have been considering retiring the plants to avoid SCR investments in May 2013 when it first made the Jim Bridger SCR commitment and did not consider future retirement as an alternative. By the time it reevaluated that commitment in December 2013, it had already begun to engage the EPA in discussions about retiring Dave Johnston Unit 3 as a way of avoiding an SCR investment. It is also important to note that the Dave Johnston decision aligns the closure date to the depreciation schedule. Because the SCR would be required five years after the EPA decision, January 2019, this means that the EPA was willing to allow the plant to operate eight years beyond its compliance date and then shut down. But in the case of the Bridger SCRs, the Company was modeling allowing the plant to operate five years beyond the compliance date associated with the Wyoming Long Term Strategy – though it belatedly added two years and also modeled retirements in 2022 and 2023.

[50] Approval, Disapproval and Promulgation of Implementation Plans; State of Wyoming; Regional Haze State Implementation Plan; Federal Implementation Plan for Regional Haze, EPA-R08-OAR-2012-0026, FRL9905-42-R08 at 45 and 46 (proposed January 10, 2014) (to be codified at 40 C.F.R. pts 52).

Q. After reviewing the 2013 IRP what is your conclusion?

A. The Company's analysis of the Bridger SCR investment was flawed. PacifiCorp claims that the analysis in the IRP was the basis for its December 2013 decision to go forward with the SCR. That analysis failed to consider a wider variety of dates for the closure to Bridger. The Company failed to engage the EPA to determine the optimal date for Bridger closure. The Company proposed closing Unit 3 first, when economic analysis suggests that it could have operated longer than Unit 4. This analysis was flawed and did not provide a reasonable basis for installing the SCRs in 2015 and 2016.

d. EPA BART Compliance Deadline

Q. Sierra Club testified that the installation of the SCRs was premature and that the Company would have had until 2019 to install them. Do you agree?

A. I agree that under Regional Haze Rules, an entity has five years after the EPA approves a State Implementation Plan (SIP) or issues its own FIP. With the EPA decision coming in 2014, this would normally provide a deadline of 2019. PacifiCorp, however, argues that it did not make this investment to comply with the EPA but it made the investment to comply with the State of Wyoming Long-Term Strategy (LTS).[51] Specifically, the Company claimed that "the requirements to install SCRs at Jim Bridger Units 3 and 4 are not 'BART' requirements; they are 'LTS' requirements[52]."

Q. Were you able to review Wyoming's LTS to confirm this?

[51] UE 374 – PAC/2500/Owens/4.
[52] UE 374 – PAC/2500/Owens/8.

A. No. CUB asked the Company to provide a copy of the Wyoming Long-Term Strategy (LTS) for regional haze compliance that created the 2015/2016 Jim Bridger Units 3 and 4 deadlines. The Company did not provide a document called a Long-Term Strategy, but did refer to two documents that reference the LTS. CUB Exhibit 405 shows that the Company responded by referring to two documents:

- Federal Register Volume 79 5013 (2014), and
- PacifiCorp Exhibit 2510.[53]

The first document is obviously not from the State of Wyoming. The Second document is a settlement of PacifiCorp's challenge of aspects of Wyoming's BART proposal. Both refer to the State of Wyoming's Long-Term Strategy, but neither provide the LTS itself or show how the LTS is binding.

The State BART settlement references LTS and would seem to be binding in its commitment to reduce emissions from Bridger Units 3 and 4, but is subject to modification if there are future changes in either:[54]

- Federal or state requirements or
- technology would materially alter the emissions controls and rates that otherwise are required hereunder**.**

The EPA did then adopt the BART settlement, but that settlement is subject to change if the federal requirements change.

Q. How should we interpret this?

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[53] CUB Exhibit 405 – PAC Response to CUB DR 12.
[54] UE 374 – PAC 2510/Owen/4.

A. Wyoming clearly had requirements for SCR installation by 2015 and 2016, but it was subject to change if the federal requirements changed. While the federal requirement normally would require the SCR in 2019, the EPA was willing to adopt the 2015 and 2016 dates. From the EPA's view, the Wyoming agreement was "better-than BART"[55] because it achieved the same 20-year reduction in pollution but it achieved it sooner. It is not surprising that the EPA would adopt it.

However, in this docket and in the IRP that considered the Bridger clean air investment, PacifiCorp claims to have seriously considered closing the plant in 2020 and 2021 as an alternative to installing SCRs. If the Wyoming LTS pollution limits on Bridger were enforceable in 2015 and 2016 then this would not have been possible. According to the Company, the LTS prevented the Company from running the plant without an SCR in to comply with the normal BART deadline of 2019, but this somehow did not prevent the Company from running the units until 2020 and 2021 and shutting them down.

This actually makes sense. The EPA was supportive of allowing Boardman, Dave Johnston, and Naughton 3 to operate without SCRs past their compliance date because it was part of a plan to close the plants. Closing a coal plant reduces

[55] In its guidance on how to comply with BART, the EPA also lists alternatives that it sees as "better-than BART" for various resource decision making issues. Achieving a result that is "better-than BART" can excuse states from complying with BART. For example, see: https://www.jdsupra.com/legalnews/csapr-is-better-than-bart-79842/

more emissions than retrofitting it. Closing a plant, therefore, is "better-than BART."

The EPA would likely have been supportive of an alternative compliance plan that retired the units. If EPA adopted such a plan, this would be cause for amending Wyoming settlement. However, installing the same SCR five years later was not "better than BART" so the EPA did not adopt this and, therefore, the Wyoming agreement was not amended.

Q. Does this mean that the later EPA deadline is irrelevant to this issue?

A. No. The fact that under Regional Haze Rules, BART required SCRs in 2019 is highly relevant. Because this means that retiring the plants in 2025 (five years beyond the compliance date like Boardman), or even 2028 (eight years beyond the compliance date like Dave Johnston) could have been "better than BART" and if this had been proposed the EPA likely would have chosen it which provided cause to amend the Wyoming settlement. The BART deadline of 2019 could have been used to evaluate retirement scenarios and this would likely have led to 2025 being a reasonable retirement scenario. If BART required an SCR in 2019, the EPA would have been evaluating two alternatives that were better: either installing SCRs early in 2015/2016 or retiring units in 2025. Since the goal of Regional Haze Rules is to return to normal background levels of regional haze by 2064, the decision to close a coal plant and eliminate all future emissions from the plant would likely have been the better alternative.

Q. What is your conclusion regarding the installation of the SCRs at Bridger Unit 3 and Unit 4?

A. The installation was imprudent. The Company rushed ahead and installed these without first analyzing alternatives that may have been lower cost. Further, the Company installed LNO and OFA prematurely in a manner that skewed the cost-effectiveness of the later SCR investment. Fundamentally, the Company failed to explore an alternative that was available to it by not engaging with the EPA to pursue a "better than BART" outcome that retired the plant as an alternative to installing the SCR. While the Company modeled a version of such an approach, it failed to engage EPA in discussions to find out what the possibilities were.

I firmly believe that there was a deal to be made. Because retiring the units was "better-than BART," the EPA was receptive and would likely have considered dates other than 2020 and 2021 – maybe as late as 2028. But the Company failed to pursue this option. While I cannot prove what the outcome of those discussions would have been – and it is possible that the outcome would not have led to retirement of Bridger 3 and 4 -- it was imprudent not to have engaged in the discussions.

e. Oregon Depreciable Life

Q. The Company says that its analysis would not have changed if it had used the Oregon depreciable life as the early closure date in its SCR analysis. Do you agree?

A. I do not agree. The Oregon depreciable life of the Jim Bridger units was 2025.[56] The Company states that "based on ratemaking treatment at the time of the analysis" the plant would not be removed from Oregon rates at the end of its useful life.[57] I agree with this, but by adding an SCR with a 20-year useful life, the Company assumes that the useful life of the Bridger units extends until at least 2035. I do not agree with this assumption. The Commission rejected extending the useful of the Bridger Units to 2037 and criticized the Company for assuming the plants will continue into the "foreseeable future" and that "any expenditures resulting from environmental regulations will be recoverable in rates." The Commission further cautioned that the continued operation of a coal plant could become uneconomic, leading to early retirement.[58]

The Company is ignoring the Commission's rejection of extending the life of Bridger, and is continuing to use the very assumptions that the Commission criticized in that rejection. An analysis based on Oregon's useful life would have examined these assumptions. It would have considered whether the plant would be economical until the mid-2030s. It would have considered whether any additional carbon regulation at the State or Federal level was likely before 2035 beyond the Clean Power Plan, which was already included in the modeling. It would have included consideration of the risks of future coal operation.

[56] OPUC Order No. 13-347.
[57] UE 374 – PAC/2300/31.
[58] OPUC Order No. 08-327

CUB agrees that when the Commission rejected extending the life of Bridger to 2037, it was not establishing a commitment to remove the plant from Oregon rates in 2025. It was, however, making clear that the Company was failing to adequately consider the risks associated with coal plants and consider that plants would close earlier than PacifiCorp was projecting – could close sometime between 2025 and 2035. The Company's analysis of Bridger was imprudent because the Company did not consider those risks in its analysis.

f. Summary of Imprudence Determination

Q. Can you summarize your arguments for why PacifiCorp's investment in the Bridger Units 3 and 4 SCRs was imprudent?

A. Yes. First, between 2011 and 2015 the Company was rushing to make more than $1 billion in clean air investment in its coal plants without an adequate review, even trying to avoid review in IRPs. Second, while the 2013 IRP review informs ratemaking in this case, the Company's 2013 analysis was inadequate, had poor assumptions, and did not consider the best alternatives to investing in the SCRs. Third, the Company failed to engage the EPA to find out what "better-than BART" alternatives were available. There is a very good chance that PacifiCorp could have gotten permission to operate these plants until 2025 without an SCR. But fundamentally, we are unable to establish what the best alternatives to an SCR were at the time, because the Company did not explore these alternatives. The Company knew, at the time, that various alternatives were available but it consciously chose not to pursue them. This is the very nature of an imprudent decision.

Once imprudence is found, the Commission must find a way to adjust rates to remove the imprudence. Often that is a difficult assignment, because it requires determining what would have happened if the investment was not put in place. While we do not know precisely what would have happened, PacifiCorp's imprudence was primarily focused on not seriously engaging in determining how long it could run the plant without the SCR if it committed to retiring the plant. We know that the Company could gain approval to run Dave Johnston for 9 years after the SCR would have been required. In this case, we are looking at ending our use of the coal plant 10 years after the SCR was required. We also know that the BART (as opposed to LTS) requirement for the SCR would have been 2019, which is just six years before the plant will be removed from Oregon rates. Therefore, CUB thinks the correct method to enact a prudence disallowance is to remove the SCR costs from the test year and continue this way through 2025. The only additional change that needs to be made is that Jim Bridger Units 3 and 4 should continue to be dispatched in the TAM as if no SCR was installed on them.

2. *Jim Bridger SCR Ratemaking.*

Q. Does CUB have any other concerns about PacifiCorp's proposal for cost recovery of the Jim Bridger SCR investment?

A. Yes. CUB is concerned that the Company, after failing to consider the risk associated with future carbon regulation at the state and federal level, is asking Oregon ratepayers to absorb this risk. While CUB believes that removing the imprudent investment is the best ratemaking treatment, the Commission could also allocate to the risk that the Company took to the Company. This can be done by allocating the cost of the SCR to Oregon customers based on how much of the investment is used and useful to Oregon customers.

In addition, CUB is concerned that the Company has incorrectly accounted for regulatory lag associated with the investment and is proposing ratemaking treatment that is not consistent with Oregon law and regulatory principles. Finally, CUB would like to respond to Staff's proposal for a management penalty.

a. Used and Useful

Q. Why do you believe that the Commission should consider allocating this cost based on how much of it is used and useful?

A. The Company is proposing cost recovery as if this is an investment that was needed, acknowledged in an IRP and is consistent with the useful life of the underlying coal unit. But this isn't the case. In rejecting PacifiCorp's proposal to extend the useful life of the Bridger plant, the Commission was clear that the Company was failing to consider the economic and environmental risks of coal plants. By asking Oregon customers to pay for this investment on an accelerated basis (necessary to pay for Oregon's share under SB 1547's commitment to get coal out of rates by 2030), the Company is asking customer to pay for the risk it refused to consider.

As an alternative, CUB believes that it is appropriate to allow recovery of these costs only to the extent that the SCR is used and useful to serve Oregon load.

This places the risks associated with the operation of the Bridger plant beyond its Oregon useful life of 2025 with the Company.

SCRs are capital investments that are evaluated as part of a BART determination based on the dollars/ton of pollutants removed during the operation of that equipment. An SCR is very much like a 20-year contract for coal. The coal contract is expected to provide a certain volume of coal each year over a 20-year contract life and an SCR is expected to provide a certain volume of pollution reduction each year over a 20-year SCR life. PacifiCorp is asking Oregon customers to pay "Oregon's share" of these costs based on an allocation of 20 years of pollution control rate base being added to a plant that is being removed from Oregon rates in the middle of that 20-year period. This means that customers are being asked to pay to remove pollution that has never even been generated. This would be like asking customers to pay for coal that has not yet been mined. If the Company had signed a 20-year coal contract in 2015, and Oregon was discontinuing using the plant but it was still in service, Oregon customers would not be asked to pay for the costs of coal that had not been mined. Instead, Oregon would be assigned its share of coal costs for the coal that fueled the plant while we took power from it. PacifiCorp might argue this is different because it is a capital investment, not a contract, but that argument is unpersuasive. If the Company had made a capital investment in 2015 that was part of the Bridger coal mine and was expected to support coal mining for the next 20 years, it would be treated in a manner like the 20-year contract. Oregon customers would be on the hook for the coal that was mined while we took power from the plant, not the coal that was mined later. Even if the coal is extracted with a capital investment. When pollution is extracted with a capital investment it should be treated the same way.

The Company will undoubtedly disagree with this approach and may claim that it violates the Multi State Process (MSP) 2020 Protocol. But MSP protocols concern themselves with allocating costs to states and do not "prejudge the prudence of the cost or *the extent to which any particular cost may be reflected in rates.*"[59] MSP protocols are not a barrier to the Commission finding that Oregon customer should only bear the cost of the SCR to the extent that it is used and useful.

Based on the EPA evaluation of a 20-year useful life of pollution removal, 25% of this investment is used and useful during the time-period between the rate effective date and the elimination of Bridger from Oregon rates. Using the current allocation factor of 26.023%, $[redacted] of the capital investment should be charged to Oregon over the next 5 years, or [redacted] per year.[60] In addition, Oregon should pay a return on the undepreciated portion of only the investment that will be used during the period Oregon is paying for it.

[59] 2020 Protocol, page 3.
[60] CUB Exhibit 406 CONF – CUB's used and useful calculation.

An even better method to determining the allocation based on used and usefulness is to connect recovery of costs to the tons of pollution removed. The starting point would be the May 2013 analysis in the Wyoming proceeding that led to the contract for installation of the SCR. That analysis was based on a dollars/ton of pollution removed over the 20-year useful life. To calculate this, PacifiCorp projected the output of the plant over 20 years and the amount of pollution that would be produced. PacifiCorp can divide that cost of the SCRs by the amount of MWh associated with the generation of that pollution in the SCR analysis and produce the value of SCR dollars per MWh of Bridger Units 3 and 4 generation. This could then be used to forecast the amount of the SCR that is used and useful each year based on the forecasted generation of the two coal units. Because how much pollution reduction is used is connected to the output of the plant, this could be added to the TAM as a variable cost of production. If the Commission decides to take this step, CUB recommends that it order the Company to hold a workshop with parties to discuss the methodology for this and include it in next year's TAM. In the meantime, for 2021, the Commission should allow the forecasted amount above: $[redacted][61] plus a return on the undepreciated portion of only the investment that will be used during the period Oregon is paying for it (2021-2025).

b. Depreciation and Regulatory Lag

Q. What are your concerns related to depreciation and regulatory lag?

[61] CUB Exhibit 406 CONF.

A. CUB is concerned that the Company assigned the incorrect depreciation rate on this investment when it came on line and therefore has inaccurately accounted for depreciation since that time. In addition, CUB is concerned that the rate treatment proposed is not consistent with the way Oregon treats rate base.

Q. How does a utility recover capital costs from ratepayers?

A. A utility recovers both the original costs of capital investment and its end-of-life net salvage value by claiming annual deprecation accruals. Depreciation expense allocates the costs of plant to ratepayers over its estimated useful life. All things equal, a longer useful life leads to a lower depreciation expense on a capital investment.

Q. Please elaborate on this.

A. The SCR on Bridger Unit 3 came online in December of 2015 and the SCR on Unit 4 came online in December of 2016. This was pollution control that was being added to a plant that had an Oregon useful life of 2025, so the capital investment should have adopted the same useful life. It does not make sense to have a longer useful life for pollution control on a plant than for the plant itself. In addition, by the time the first SCR came online, environmental groups had filed versions of a proposed ballot measure that would have phased out the use of coal plants to serve Oregon load before 2030. PacifiCorp, CUB and other stakeholder had engaged in discussions which became SB 1547, legislation that mandates that Oregon customers cannot pay for coal plants after 2030. By the time the second SCR was placed in service, that law had passed and it was unlawful to charge Oregon customers for coal investments after 2030.

When the SCR came on line, PacifiCorp assigned them a depreciation rate of [redacted] which would depreciate the investment over approximately 20 years.[62] This can be verified by taking the total rate base of the two plants and dividing by the approximate annual depreciation, which produces a [redacted] depreciation life:

Rate Base Unit 3[63]	[redacted]
Rate Base Unit 4[64]	[redacted]
Total	[redacted]
Annual Depreciation[65]	[redacted]
Depreciation length	[redacted]

But because underlying plant had an Oregon useful life of 2025, the pollution control added to it cannot have a useful life of 2035. The effect of using a longer useful life for the plant from 2015 through 2020 is to reduce the regulatory lag absorbed by the Company. The Company has not sought to add the Bridger SCRs into rates since the investments became useful in 2015 and 2016. The proper treatment of this period is to have the plants depreciate during this period with depreciation expense associated with the 2025 Oregon useful life.

Q. How should the plants be treated for depreciation and regulatory lag?

[62] CUB Exhibit 307 CONF, Staff DR 750.
[63] CUB Exhibit 308 CONF, DR 4 supplemental.
[64] CUB Exhibit 309 CONF, DR 5 supplemental.
[65] CUB Exhibit 307 CONF, Staff DR 750.

A. CUB Exhibit 410 shows that when the depreciation schedule is changed in order to have the plant depreciated by the end of 2025 to correspond to the useful life of the Bridger plant, the amount that is already depreciation and therefore subject to regulatory lag increases from [redacted]. This amount should be used for ratemaking purposes.

Q. How is PacifiCorp's ongoing treatment not consistent with Oregon ratemaking?

A. Under PacifiCorp's version of depreciation and regulatory lag there is approximately [redacted] left to recover from Oregon customers for the SCRs. PacifiCorp's is proposing that [redacted] be amortized in 2021. However, this means that it will require charging customers through 2029 to fully amortize this amount.[66] This will require customers to pay for the SCR after the Bridger plant is no longer serving Oregon customers. Because Oregon law and policy prohibit charging customers for rate base that is not presently used to serve customers,[67] it seems clear that PacifiCorp cannot change customers for the SCR after 2025. While there is an exception to this for property that is retired in the public interest, CUB does not believe that an operating coal plant which no longer serving Oregon meets the definition of retired plant.

Under CUB's calculation of regulatory lag, the remaining investment recoverable from Oregon customers is [redacted] To pay this off while the SCR is still used and useful would require a charge of [redacted] per year.

[66] CUB Exhibit 410 CONF.
[67] ORS 757.355.

CUB is not recommending this amount for recovery. It is larger than the amount the Company is requesting, though it is only for five years, not for ten years. It represents the amount that Oregon should pay to accelerate the SCR to fully pay off "Oregon's share" by 2025. It correctly treats regulatory lag and ends recovery when the investment is no longer presently use. But it is still flawed in that it is asking for Oregon customers to pay for a 20 years of SCR pollution reduction in 10 years.

3. *Staff Management Penalty*

Q. Did you review OPUC Staff's proposal to assign a management penalty to this investment?

A. Yes. Staff is proposing a 10% penalty,[68] which is similar to what the Commission decided in UE 246. CUB appreciates Staff's analysis of the Bridger SCR investments. However, CUB believes that full disallowance, rather than a partial disallowance is warranted in this case.

If the Commission declines a full disallowance of the SCR costs, then the Commission should first adjust for used and usefulness, proper depreciation, return on capital investment and regulatory lag before assessing any penalties. Only after these steps to determine what should properly be assigned to customers, should the Commission properly assess a penalty.

[68] UE 374 – Staff/700/19-20.

III. CONCLUSION

Q. What are CUB's recommendations in this proceeding?

A. CUB makes the following recommendations:

COVID-19. COVID-19 has had significant effects on Oregon's economy and many customers are suffering. PacifiCorp should recognize this hardship and eliminate or reduce proposed cost increases and policy changes that add to this burden. If PacifiCorp is unable to do so, the Commission should do so.

Cost of Capital. PacifiCorp's proposal to increase its return on equity should be rejected. Instead, authorized ROE should be set in the lower half of the reasonable range and should be no higher than 9.4%

Power Cost Adjustment Mechanism (PCAM). PacifiCorp's proposal eliminates the deadbands, sharing and earnings test associated with the current PCAM and should be rejected. The current PCAM is well-designed and creates proper incentives for utilities.

Wheeling Revenue. Wheeling revenue should be removed as an item in the General Rate Case and instead should be forecast in the annual power cost proceeding (TAM). This represents a change to the TAM Guidelines.

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Jim Bridger Unit 3 and Unit 4 SCRs.

1. The Commission should find the SCRs to be imprudent and deny the Company cost recovery of those investments. The Company's analysis before making the investment was flawed and incomplete, the Company failed to explore the flexibility that was available to it and the Company did not consider Oregon's limited useful life.

2. If the Commission does not agree to a full prudence disallowance, it should recognize Oregon's useful life and the risks that the Company was taking by investing in pollution control that exceeded that life. This can be done by allocating costs based on the amount of the investment that is used and useful.

3. If the Commission does decide to allocate rate base associated with the Bridger SCRs, it should first correct the depreciation and regulatory lag calculation and recognize that the useful life of the SCR cannot be longer than the Bridger units themselves.

Q. Does this conclude your testimony?

A. Yes.

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ISSUER COMMENT
17 July 2020

Rate this Research

RATINGS

Puget Sound Energy, Inc.

Domicile	Bellevue, Washington, United States
Long Term Rating	Baa1
Type	LT Issuer Rating - Dom Curr
Outlook	Stable

Puget Energy, Inc.

Domicile	Bellevue, Washington, United States
Long Term Rating	Baa3
Type	LT Issuer Rating - Dom Curr
Outlook	Stable

Source: Moody's Investors Service

Contacts

Nana Hamilton +1.212.553.9440
AVP-Analyst
nana.hamilton@moodys.com

Michael G. Haggarty +1.212.553.7172
Associate Managing Director
michael.haggarty@moodys.com

CLIENT SERVICES

Americas	1-212-553-1653
Asia Pacific	852-3551-3077
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Puget Sound Energy, Inc.

Puget Sound Energy's rate case outcome is credit negative

On 8 July 2020, Puget Sound Energy, Inc. (PSE) received a final order from the Washington Utilities and Transportation Commission (WUTC) on electric and gas general rate cases initially filed by the utility in June 2019. The WUTC authorized an electric revenue increase of \$29.5 million or 1.6% but extended the amortization of certain regulatory assets, effectively reducing the revenue increase to \$857,000 or 0.05%. With respect to gas operations, the commission also extended regulatory asset amortization, lowering its authorized revenue increase of \$36.5 million or 4% to \$1.3 million or 0.15%. PSE had requested rate increases of \$139.9 million or 6.9% and \$65.5 million or 7.9% for electric and gas operations respectively. The commission also authorized a below industry average return on equity of 9.4%, slightly lower than the utility's requested and previously allowed ROE of 9.5%, and an equity capitalization of 48.5%, equal to the utility's request and previously authorized equity capitalization.

The desire to limit customer rate increases in light of the uncertain economic environment caused by the coronavirus pandemic was an important driver of the WUTC's decisions. Nevertheless, the rate case outcome is credit negative for PSE and parent Puget Energy, Inc. (Puget) because it will constrain cash flow growth which, together with higher debt to help fund about \$2 billion of capital investments over the last two years, will pressure credit metrics.

Without any management actions to mitigate the negative cash flow impact of the rate case outcome, we estimate that PSE and Puget's credit metrics will remain on the weak end of our expected range for the credit, with operating cash flow before working capital changes (CFO pre-WC) to debt ratios in the high teens at PSE and around 11-12% at Puget over the next two years.

Both PSE and Puget have seen their debt coverage metrics deteriorate steadily since a favorable multi-year rate plan ended in 2017. The companies' credit metrics were particularly low in 2019 because of the adverse effects of an Enbridge Inc. (Baa2 positive) pipeline rupture and a colder than normal winter on purchased gas costs. These costs are being recovered over a three year period instead of the usual one year time frame to reduce the impact on customers. Still, even after adjusting for the purchased gas receivable, PSE's and Puget's 2019 credit metrics were lower than historical levels, with estimated CFO pre-WC to debt ratios of approximately 18% and 11%, respectively, compared with 20.3% and 12.9% in 2018 and 24% and 14.6% in 2017.

Although PSE's regulatory proceedings since 2017 have been characterized by some contention, we had expected Washington's Clean Energy Bill, passed in May 2019, to result in more credit supportive outcomes for the utility. The clean energy legislation includes the potential for enhanced cost recovery mechanisms that can improve utility financial performance and provides a legal and regulatory framework to reduce carbon exposure. The law acknowledges the WUTC's authority to implement performance and incentive based regulation, multiyear rate plans and other "flexible regulatory mechanisms" to achieve the state's public interest objectives. The bill's application by the WUTC will ultimately determine its benefits to utilities. However, given current economic conditions, the WUTC's focus was on mitigating the economic impact of the coronavirus pandemic on PSE's customers.

Other notable provisions of the rate case order include:

» Rejection of PSE's attrition adjustment proposal as not in the public interest at this time.

» To help mitigate regulatory lag, approval of an end of period rate base valuation and approval of certain pro-forma capital additions such Get to Zero investments to improve customer experience and advanced metering infrastructure (AMI) through the end of 2019.

» A requirement that PSE continue deferring the recovery of a return on AMI investments, though deemed prudent, until the completion of the project when the benefits to all customers would be evaluated.

» A requirement that PSE return unprotected excess deferred income taxes (EDIT) associated with tax reform over a three year amortization period and return 2019 and 2020 protected EDIT over a 12 month period.

» Disallowance of recovery of $7.2 million of costs to install SmartBurn controls at Colstrip units 3 and 4, citing a failure on PSE's part to maintain contemporaneous documentation of decision making.

The rate case order is still within the adjudicative process where PSE can file for reconsideration by the WUTC and petition a Washington Superior Court to review the order.

REPORT NUMBER 1237958

CLIENT SERVICES

Americas	1-212-553-1653
Asia Pacific	852-3551-3077
Japan	81-3-5408-4100
EMEA	44-20-7772-5454

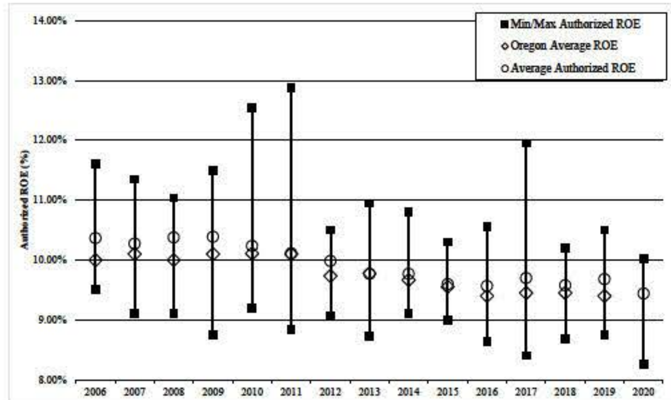
Moody's INVESTORS SERVICE

CHART

AUTHORIZED ROE - NATURAL GAS/ELECTRIC DISTRIBUTION UTILITIES

Line		National Authorized ROE			Oregon	National
No.	Date	Maximum	Minimum	Average	Average	Count
1	2006	11.60%	9.50%	10.37%	10.00%	40
2	2007	11.35%	9.10%	10.27%	10.10%	71
3	2008	11.04%	9.10%	10.38%	10.00%	67
4	2009	11.50%	8.75%	10.39%	10.10%	68
5	2010	12.55%	9.19%	10.23%	10.11%	97
6	2011	12.88%	8.83%	10.11%	10.10%	55
7	2012	10.50%	9.06%	9.98%	9.73%	85
8	2013	10.95%	8.72%	9.77%	9.78%	61
9	2014	10.80%	9.10%	9.77%	9.67%	58
10	2015	10.30%	9.00%	9.60%	9.55%	39
11	2016	10.55%	8.64%	9.57%	9.40%	57
12	2017	11.95%	8.40%	9.70%	9.45%	65
13	2018	10.20%	8.69%	9.58%	9.45%	77
14	2019	10.50%	8.75%	9.68%	9.40%	63
15	2020	10.02%	8.25%	9.44%		27

Min/Max Authorized ROE
Average Authorized ROE
Oregon Average ROE



CUB Exhibit 403 is confidential and will be provided to parties that have executed Protective Order No. 20-040.

CUB Exhibit 404 is confidential and will be provided to parties that have executed Protective Order No. 20-040.

UE 374/PacifiCorp
July 8, 2020
CUB Data Request 12

CUB Data Request 12

Please provide a copy of the Wyoming Long-Term Strategy (LTS) for regional haze compliance that created the 2015/16 Jim Bridger Units 3 and 4 SCR deadlines.

Response to CUB Data Request 12

Please refer to Federal Register Volume 79 5031(2014) and James Owen's Exhibit PAC/2510.

CUB Exhibit 406 is confidential and will be provided to parties that have executed Protective Order No. 20-040.

CUB Exhibit 407 is confidential and will be provided to parties that have executed Protective Order No. 20-040.

CUB Exhibit 408 is confidential and will be provided to parties that have executed Protective Order No. 20-040.

CUB Exhibit 409 is confidential and will be provided to parties that have executed Protective Order No. 20-040.

CUB Exhibit 410 is confidential and will be provided to parties that have executed Protective Order No. 20-040.